ENVIRONMENTAL LAW & POLICY CENTER
Protecting the Midwest's Environment and Natural Heritage

June 25, 2020

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P. O. Box 30221
Lansing, MI 48909

RE: MPSC Case No. U-20697

Dear Ms. Felice:

Ecology Center, Environmental Law & Policy Center, Great Lakes Renewable Energy Association, Solar Energy Industries Association and Vote Solar (collectively Joint Clean Energy Organizations or JCEO) submitted Direct Testimony in MPSC Case No. U-20697 on June 24, 2020. Separately and also on June 24, 2020, JCEO submitted Exhibits to their Direct Testimony.

Subsequent to submitting those filings, we noticed that the filed Direct Testimony pdf contained certain non-final draft testimony. In order to correct this oversight, we have attached for paperless electronic filing:

> Corrected PUBLIC Direct Testimony and Exhibits of William D. Kenworthy, Kevin Lucas, Claudine Y. Custodio, Dr. Gabriel Chan, Karl R. Rábago, and Ronny Sandoval on behalf of the Ecology Center, the Environmental Law & Policy Center, Great Lakes Renewable Energy Association, the Solar Energy Industries Association and Vote Solar (Joint Clean Energy Organizations or JCEO).
>
> Proof of Service

The attached document makes several minor non-substantive changes to the Direct Testimony of the JCEO filed on June 24, 2020. We have served the attached document on all parties.

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David C. Wilhelm, Chairperson • Howard A. Learner, Executive Director
Chicago, IL • Columbus, OH • Des Moines, IA • Duluth, MN • Grand Rapids, MI
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Sincerely,

Nikhil Vijaykar
Environmental Law & Policy Center
nvijaykar@elpc.org

cc: Service List, Case No. U-20697

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY for	)	
authority to increase its rates for the	)	Case No. U-20697
generation and distribution of electricity and	)	
for other relief.	)	

DIRECT TESTIMONY OF

WILLIAM D. KENWORTHY

ON BEHALF OF

THE ECOLOGY CENTER
THE ENVIRONMENTAL LAW & POLICY CENTER
THE GREAT LAKES RENEWABLE ENERGY ASSOCIATION
THE SOLAR ENERGY INDUSTRIES ASSOCIATION
AND VOTE SOLAR

June 24, 2020

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I. NAME AND QUALIFICATIONS

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

A: My name is William D. Kenworthy. My business address is 322 South Michigan Avenue, 9th Floor, Chicago, Illinois 60604.

Q: By whom are you employed and in what capacity?

A: I serve as Regulatory Director, Midwest for Vote Solar. I oversee policy development and implementation related to large scale and distributed solar generation in the region. I also review regulatory filings, perform technical analyses, and testify in commission proceedings on issues relating to solar generation.

Vote Solar is an independent 501(c)3 nonprofit working to repower the U.S. with clean energy by making solar power more accessible and affordable through effective policy advocacy. Vote Solar seeks to promote the development of solar at every scale, from distributed rooftop solar to large utility-scale plants. Vote Solar has over 90,000 members nationally, including over 2,700 members in Michigan. Vote Solar is not a trade organization nor does it have corporate members.

Q: On whose behalf are you submitting this direct testimony?

A: I appear here in my capacity as an expert witness on behalf of the Ecology Center, Environmental Law & Policy Center ("ELPC"), the Great Lakes Renewable Energy Association ("GLREA"), the Solar Energy Industries Association ("SEIA"), and Vote Solar (collectively, the "Joint Clean Energy Organizations" or "JCEO").

Q: Can you please summarize your qualifications, experience and education?

A: I have nearly 30 years of experience in the energy industry in both the public and private sectors working in the renewable energy business and in energy policy. Of that experience, I spent eight years in solar energy project development working primarily on commercial and industrial distributed solar projects in the Midwest.

Prior to Vote Solar, I was Managing Director – Midwest for Microgrid Energy, where I was responsible for leading Microgrid Energy's expansion of its solar project development capabilities into markets in the Midwest. As a solar project developer, I analyzed financial and economic aspects of projects. This involved understanding all aspects of project finance and economics for our customers, partners, and financiers. My project development experience includes project finance, rate analysis, economic modelling, risk assessment, regulatory compliance, sales, and customer relations.

During my tenure at Microgrid Energy, we completed the Solar Chicago program, a residential bulk purchase program, as well as a number of commercial projects ranging in size from 25 kW to 2 MW. Prior to that, I was a partner with Tipping Point Renewable Energy based in Dublin, Ohio, where we developed what was at the time the largest rooftop solar project in Ohio for the City of Columbus.

In addition, my tenure at Microgrid Energy was punctuated with a one-year hiatus during which time I served as President of Infer Energy, currently Root3 Technologies. Infer Energy provided energy optimization services to large commercial and industrial energy users. We used advanced data analytics and machine learning algorithms to optimize complex energy systems. Prior to joining the solar energy industry, I worked on energy policy at the federal and state level for over 20 years. As a consultant, I represented electric utilities and other industry participants before Congress, the Department of

Energy, the Nuclear Regulatory Commission, the Environmental Protection Agency, and the Office of Management and Budget. I began my career as a Professional Staff Member to the House Energy & Commerce Committee, where I represented Chairman John D. Dingell and other majority members of the Committee in negotiations and legislative drafting on nuclear regulatory matters, the Clean Air Act Amendments of 1990, and electric industry structure issues, among others.

I received a Master of Public & Private Management degree from the Yale University School of Management with a concentration in Regulation and Competitive Strategy. My research in graduate school focused on regulatory theory and practice. I also have a Bachelor of Science in Foreign Service from Georgetown University.

Q: Have you testified before the Michigan Public Service Commission Previously?

A: Yes. I provided testimony in Case No. U-20162 (DTE Rate Case), Case No. U-20471 (DTE IRP), Case No. U-20359 (I&M Rate Case), Case No. U-20561 (DTE Rate Case), and Case No. U-20649 (Consumers VGP Case).

Q: Have you testified or provided comments in similar state regulatory proceedings?

A: Yes. In addition to testimony noted above before the Michigan Public Service Commission, I have provided testimony in rate cases before the Iowa Utilities Board and the Wisconsin Public Service Commission. I have provided testimony on community solar services before the Illinois Commerce Commission. I also have provided comments in numerous proceedings before the Illinois Commerce Commission, the Illinois Power Agency, the Minnesota Public Utility Commission, and the Wisconsin Public Service

Commission. A list of testimony and comments that I have filed is included as Exhibit ELP-1 (WDK-1).

Q: Are you sponsoring any exhibits?

A: Yes, I am sponsoring the following exhibit:

- Exhibit CEO-1 (WDK-1): Testimony and Comments of William D. Kenworthy
- Exhibit CEO-2 (WDK-2): U20697-MEIBC-CE-198
- Exhibit CEO-3 (WDK-3): U20697-MEIBC-CE-199
- Exhibit CEO-4 (WDK-4): U20697-MEIBC-CE-200
- Exhibit CEO-5 (WDK-5): U20697-MEIBC-CE-202

II. PURPOSE AND SUMMARY

Q: What is the purpose of your Direct Testimony?

A: The purpose of my testimony is to discuss certain aspects of Consumers Energy Company's ("Consumers" or the "Company") proposal in its filing that impact distributed generation ("DG"). My testimony covers several subjects. First, in Section III of this testimony, I describe the history and scope of the proposals made by the Company related to distributed generation in this docket. In Section IV, I provide an analysis of the impacts of the Company's proposed DG Program on prospective DG customers. In Section V of my testimony, I introduce the witnesses who are testifying on behalf of the JCEO and provide a summary of the topics addressed in each testimony. Those witnesses are:

- Mr. Kevin Lucas: analysis of the cost to serve DG customers.

- Ms. Claudine Custodio: analysis of customer load data.
- Dr. Gabe Chan: discussion of Minnesota Value of Solar process.
- Mr. Karl Rábago: principles of ratemaking applied to DG.
- Mr. Ronny Sandoval: discussion of value of DG to the distribution grid.

In section VI, I describe the recommended changes to the Company's Distributed Generation Program as informed by the analyses conducted by the JCEO witnesses. In Section VI, I briefly discuss the statutory cap on distributed generation and recommend that the Company voluntarily extend the cap. In Section VII, I describe recommendations made for the Commission to initiate a proceeding to further standardize the treatment of distributed generation across all jurisdictional utilities.

Q: Please summarize your conclusions and recommendations.

A: The testimony of the JCEO witnesses illustrates that it is timely, feasible, just and reasonable for the Commission to require the Company to revise its DG Program to provide a cost-based outflow credit to customers that fully and fairly compensates DG owners for the value of their outflow within the context of the Company's existing Cost of Service Study (COSS). In addition, in light of the experience and data that the Commission and utilities in Michigan have accumulated in the past several years, especially since the deployment of advanced metering infrastructure and the visibility into the system provided by distribution and resource planning, we recommend that the Commission initiate a comprehensive statewide study into the Value of Solar.

III. HISTORY AND SCOPE OF DISTRIBUTED GENERATION PROGRAM

Q: What is the statutory background for this proceeding?

A: On December 21, 2016, Governor Rick Snyder signed 2016 PA 341 ("Act 341") into law. Section 6a(14) of Act 341 directs the Commission to "conduct a study on an appropriate tariff reflecting equitable cost of service for utility revenue requirements" and to "approve such a tariff" in a rate case filed after June 1, 2018.

Q: What action has the Commission taken to implement the requirements of Section 6a(14) of Act 341?

A: In response to Act 341, the Commission initiated a proceeding to study "an appropriate tariff reflecting equitable cost of service for utility revenue requirements." The Commission opened Case No. U-18383, *In the matter, on the Commission's own motion, to implement the provisions of sections 173 and 183(1) of 2016 PA 342, and section 6a(14) of 2016 PA 341*.

At the Commission's direction, the Commission Staff convened a Distributed Generation Workgroup ("DG Workgroup") that held a number of meetings between March and December 2017. As a result of these meetings, the Staff issued a report titled, *Report on the MPSC Staff Study to Develop a Cost of Service-Based Distributed Generation Program Tariff* ("Staff Report"), on February 21, 2018.[1] In that report, the Staff recommended a new approach to billing DG customers referred to as the Inflow/Outflow billing method ("Inflow/Outflow method").

Q: Please describe the Inflow/Outflow billing method.

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[1] Case No. U-18383, Report on the MPSC Staff Study to Develop a Cost of Service-Based Distributed Generation Program Tariff, Michigan Public Service Commission Staff (February 21, 2018).

A: The Inflow/Outflow method bills inflows and outflows of power to and from a customer separately, and would replace the former net metering method, which billed inflows and credited outflows at the same rates. The Staff provided a framework tariff that adhered to the Inflow/Outflow method.

In its April 18, 2018, decision in Case No. U-18383, the Commission ordered "that, in any rate case filed after June 1, 2018, the rate-regulated utility must file the Inflow/Outflow tariff, attached to this order as Exhibit A: The rate-regulated utility may also file its own distributed generation tariff, if desired."[2] Importantly, the Commission also found that, "As the DG program evolves and more data becomes available, the Commission will better be able to assess the cost and benefit impacts and conduct rate design consistent with COS principles."[3]

Q: Has any utility filed a Distributed Generation Program pursuant to requirements of Act 341?

A: Yes. DTE Electric Company was the first utility in Michigan to file a rate case after June 1, 2018. DTE filed its case on July 6, 2018 in Case No. U-20162, *In the matter of the application of DTE ELECTRIC COMPANY for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority*. As part of that case, DTE proposed a modified version of the Commission-recommended method that did not provide a credit for the capacity value of customers' outflows and proposed a monthly charge on distributed

[2] Commission Order, *In the matter, on the Commission's own motion, to implement the provisions of Sections 173 and 183(1) of 2016 PA 342 and Section 6a(14) of 2016 PA 341*, Case No. U-18383, April 18, 2018, Exhibit A "Distributed Generation Tariff," p. 4.

[3] April 18, 2018 Order in U-18383, pg 17.

generation customers, called a System Access Contribution charge. Subsequently, the Upper Peninsula Power Company (UPPCo) filed a rate case (U-20276) on September 21, 2018. A settlement agreement was entered into in this case and the Commission issued an order approving the settlement agreement on May 23, 2019.[4] Finally, on June, 24, 2019, the Indiana Michigan Power Company filed a rate case (U-20359) that included a DG Tariff. A settlement agreement was entered into in this case as well, and the Commission issued an order approving the settlement agreement on January 23, 2020.[5]

Q: Did the Commission approve the outflow credit that DTE proposed in case U-20162?

A: No. In its final order in the DTE case on May 2, 2019,[6] the Commission rejected several elements of DTE's proposed DG tariff, including the outflow credit. Instead, the Commission accepted the Staff's proposal to set the outflow credit using values from DTE's cost of service study:

> [T]he Commission finds the Staff's proposal to credit all outflows at power supply less transmission to be the most reasonable and prudent methodology based on the record in this case.[7]

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[4] Commission Order *In the matter of the application of Upper Peninsula Power Company for authority to increase electric rates in the State of Michigan.,* Case No. U-20276, May 23, 2019.
[5] Commission Order, *In the matter of the application of INDIANA MICHIGAN POWER COMPANY for authority to increase its rates for the sale of electric energy and for approval of depreciation rates and other related matters,* Case No. U-20359, January 23, 2020.
[6] Commission Order, , *In the matter of the application of DTE ELECTRIC COMPANY for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority,* Case No. U-20162, May 2, 2019.
[7] U-20162, Final Order, pg. 190.

The ”power supply component” of the rate schedule includes all power supply charges, which include energy, capacity, transmission and certain ancillary services charges. While the Staff recommended removing transmission charges for DG outflows from the power supply component in the DTE case,[8] the Staff explained that its recommendation represented only a “starting point” that should evolve over time as more methods become available to accurately measure the value of the services created by distributed generation.[9] This perspective is consistent with the Commission’s Order in Case No. U-18383, which stated that “as the DG program evolves and more data becomes available, the Commission will be better able to assess the cost and benefit impacts and conduct rate design consistent with COS principles.”[10]

In its Order in the U-20162, the Commission concluded:

> Based on the evidence in this case, the Commission agrees with the ALJ’s recommendation to adopt the Staff’s proposal to calculate the outflow credit based on power supply less transmission.[11]

However, having considered these arguments for a full DG valuation, the Commission continued to support the proposition that further refinement of DG value should be explored:

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[8] U-20162, 8 Tr. 3436.
[9] U-20162, 8 Tr. 3434.
[10] U-18383, Order of April 18, 2018, pg. 17.
[11] U-20162, Final Order, pg. 180.

> The Commission further finds that it would be premature to direct the company to undertake a power-outflow study at this time. Nevertheless, the Commission will continue to monitor implementation and adoption of DG tariffs in other upcoming electric rate cases as required by the April 18, 2018 order in Case No. U-18383 and MCL 460.6a(14), and may reconsider the necessity of a power-outflow study at a later date.[12]

Q: How did the Commission rule on DTE's proposed System Access Contribution?

A: The Commission rejected DTE's proposed additional monthly fee for DG customers, which DTE called a "System Access Contribution" (SAC) charge.

> The Commission agrees with the Staff, the Attorney General, the Joint Solar Advocates, GLREA, MEIBC/IEI, and the ALJ and adopts the ALJ's recommendation to reject DTE Electric's SAC charge in this case. As stated by the ALJ, the company's SAC charge is neither [cost-of-service] COS-based, as required by MCL 460.6a(14), nor equitable. PFD, pp. 285-286.[13]

Q: Can you provide another example of an outflow credit that the Commission has approved?

A: Yes. In the order approving the Settlement Agreement in the UPPCo rate case, Case No. U-20276, the Commission approved a DG Program rider that included an outflow credit equal to the full power supply component of the DG customer's rate schedule:

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[12] U-20162, Final Order, pg. 182.
[13] U-20162, Final Order, pg. 198.

> UPPCo's DG tariff rider also establishes, among other things, an outflow credit equal to the power supply component of a DG customer's rate schedule, for the metered quantity of the DG customer's generation not used on site and exported to the utility during the billing month or time-based pricing period, which shall be applied to the current billing month, with any excess credit carried forward to subsequent billing periods.[14]

In addition, the Commission approved a settlement in the Indiana Michigan Power Company's rate case (U-20359)[15] including a DG tariff that is structurally very similar to the DG program approved in the UPPCo case.

Thus, unlike DTE's current DG Tariff, the UPPCo DG Rider and the Indiana Michigan Power Company's DG Rider both include transmission in compensation for outflows, which is an element of the full power supply component of the rate.

Q: Has the Commission previously indicated that an comprehensive review of the value of distributed generation to the grid would be appropriate?

A: Yes. Once again, I would refer to the Commission Order in U-18383, in which the Commission found, "As the DG program evolves and more data becomes available, the Commission will better be able to assess the cost and benefit impacts and conduct rate design consistent with COS principles."[16] Likewise, the Commission subsequently

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[14] U-20276 Final Order, pp. 3-4.
[15] U-20359, *In the matter of the Application of INDIANA MICHIGAN POWERCOMPANY for authority to increase its rates for the sale of electric energy and for approval of depreciation rates and other related matters*
[16] April 18, 2018 Order in U-18383, pg 17.

reaffirmed this sentiment in its Order in U-20162, in which the Commission indicated that it "may reconsider the necessity of a power-outflow study at a later date."[17]

Q: Do you believe that it would be timely for the Commission to revisit the methodology for calculating the value of outflow from distributed generation?

A: Yes. In light of the testimony submitted by the JCEO in this case, as introduced in Section V of this testimony, I recommend that now is the time for the Commission to revisit this issue.

Q: What has changed since the Commission's ruling in U-20162 that demonstrates the timeliness of a review of cost-based valuation of distributed generation?

A: A number of important developments have occurred since the Commission's Order in DTE's rate case (U-20162) and the settlements in the UPPCo and Indiana Michigan Power Company cases (U-20276 and U-20359, respectively):

- Multiple years of inflow and outflow data are now available to conduct a data-informed, robust analysis. The two largest utilities in the state, including the Company that is the subject of this proceeding, have fully deployed Advanced Metering Infrastructure that provides granular data on individual customers' use of the system. In response to discovery in this case, the Company provided NEM customer data as far back as 2017. JCEO Witness Mr. Lucas provides two examples of methodologies for utilizing NEM data in the Company's existing

[17] U-20162, Final Order, pg. 182

cost of service studies to calculate the value of outflow at times during which NEM customers provide energy and services to the grid.

- Michigan has implemented a distribution system planning framework that has seen the initial distribution system plans from the three largest utilities. The plans produced in the first round of distribution system plans (DTE and Consumers in early 2018 and Indiana Michigan Power Company in early 2019) set in motion a robust process for providing transparency and visibility into the planning and operation of the distribution system. JCEO Witness Mr. Sandoval explains how the distribution system planning, grid modernization, and compensation for distributed energy resources (DERs) can and should inform each other.
- The integrated resource planning process provides insight into the resource value of distributed energy resources.
- All utilities in the state have seen an increase in adoption of distributed generation and have gained experience in operating their systems in the presence of distributed energy resources. While DG penetration remains far below the penetration of many other states, Michigan's jurisdictional utilities are approaching the statutory caps for penetration, reflecting thousands of DERs currently participating across the state.
- A number of states throughout the Midwest and across the country have conducted thorough analyses of the value of solar and can provide insight into effective processes and methodologies for full and fair valuation of distributed

energy resources. JCEO Witnesss Dr. Chan provides considerable insight into the calculation of the Value of Solar in Minnesota.

IV. BILL IMPACT ANALYSIS

Q: What is the purpose of this section of your testimony?

A: I describe a bill impact analysis I conducted in order to analyze the impacts of the Company's proposed DG Program on distributed generation customers. In order to understand the impact of the proposed program, I did two different analyses. The first analysis was a Typical Customer analysis using data from DOE datasets. The second analysis used existing net metering customer data provided in discovery to examine the impacts that the proposed DG Program could have across the population of existing systems.

Q: Please describe the data you used to conduct your Typical Customer analysis.

A: My bill impact analysis combines a "typical customer" load profile for a base-use electricity customer in the Company's service territory with a typical rooftop solar installation. For the solar production data, I modeled a 7 kW system located in Jackson, Michigan using default settings "normal" for an optimally situated residential array using NREL's System Advisor Model ("SAM").[18] Using those default settings, SAM calculated the array would generate 8,890 kWh in the first year.

I then selected a typical customer load profile using a data set available from the Department of Energy available within the SAM software. The DOE dataset Commercial

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[18] System Advisor Model, National Renewable Energy Laboratory, Version 2020.2.29.

and Residential Hourly Load Profiles for all TMY3 Locations in the United States includes representative energy use profiles for residential customers throughout the United States.[19] The "base" load profile for this location is a customer that uses 9,112 kWh per year.

Finally, to compare apples to apples in the analysis, I modeled the electricity rates that have been proposed in this case to compare the total bills, simple payback, and net present value of the difference between net energy metering and the Company's proposed DG Program to understand the impact of the change to the DG tariff.

SAM can model five different methods for compensating system owners for electricity generated by their system. For this analysis, I used the "net energy metering" and "net billing with carryover to next month" to approximate the difference between the Company's current NEM tariff and the proposed Distributed Generation Program. While the Distributed Generation Program differs slightly from the results generated by using the "net billing with carryover to next month" setting, the basic method of calculating inflow and outflow at different rates and using instantaneous netting of inflow and outflow is the same. As such, it provides a close enough approximation to illustrate the difference in this hypothetical example.

Q: What were the results of your Typical Customer analysis?

A: A comparison of the financial outlook of the customers in each example is shown in Table 1:

[19] Commercial and Residential Hourly Load Profiles for all TMY3 Locations in the United States, available here: https://openei.org/doe-opendata/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-states

Table 1: Comparison of Net Metering Program to Proposed DG Program

	Net Energy Metering (old program)	Proposed Distributed Generation Program	Difference
Annual Electricity Bill with No Solar	$1,640	$1,640	
Annual Bill with System (Year 1)	$139	$529	**$390**
Net Present Value of Investment	$1,903	-$2,789	**-$4,692**
Simple Payback	9.2 years	12.7 years	**Adds 3.5 years**

This analysis shows that a typical customer sizing a solar array to meet approximately 90% of their annual energy usage would pay $390 per year more on their electricity bill than if that same customer were receiving service under net energy metering. Put another way, over the life of the system, the net present value of the distributed energy system would go from $1,903 to -$2,789, or a loss in value of nearly $4,700 over the life of the system.

Q: Were you able to conduct a broad study of the impact of the proposed DG Program on existing NEM customers on the Company's system?

A: Yes, I conducted an analysis of the actual impact that the proposed DG Program would have had on all of Consumers Energy's existing net metering customers using 2018 meter data. I used the data provided by the company to calculate the average increase in the annual bill that actual residential solar customers would experience resulting from the change to the DG Program. Again, understanding that existing Net Metering customers taking service under the NEM tariff will continue to receive service for ten years from the original date of enrollment in the net metering program, this analysis simply seeks to show the distribution of impacts across the service territory using actual systems installed by Consumers' customers.

Q: Please describe the results of the bill impact analysis.

A: My analysis shows that on average current Net Energy Metering customers would pay on average $17/month more if they were moved to the DG Program. This represents a 62% increase in their annual bill resulting from a change in the crediting methodology.

V. <u>INTRODUCTION OF JOINT CLEAN ENERGY ORGANIZATION WITNESSES</u>

A. <u>Testimony of Kevin Lucas</u>

Q: What are the key findings and conclusions of JCEO Witness Kevin Lucas?

A: Mr. Lucas provides an analysis of the cost to serve distributed generation customers. This framework is particularly important in this case because of the statutory requirement that a distributed generation tariff successor to the Net Energy Metering program must be based on an "equitable cost of service."

Mr. Lucas rebuts the findings of the Brattle Report and explains a number of analytical and methodological problems with that Report. Mr. Lucas concludes that the findings of the Brattle Report should be dismissed.

Mr. Lucas then discusses the results of his own analysis of the proper treatment of outflow energy in the cost of service study. He demonstrates that residential NEM customers are less costly to serve than non-NEM customers. Mr. Lucas also finds that the Company's proposed outflow credit is not a substitute for the proper treatment of the outflow energy in the cost of service study. He explains why outflow energy should be included in the COSS as it legitimately reduces the load of the entire residential class during critical load hours. By failing to include NEM customer outflow in the load study, the Company penalizes all members of the rate class (both participants and non-participants) by overstating the class's contribution to peak loads used in rate design.

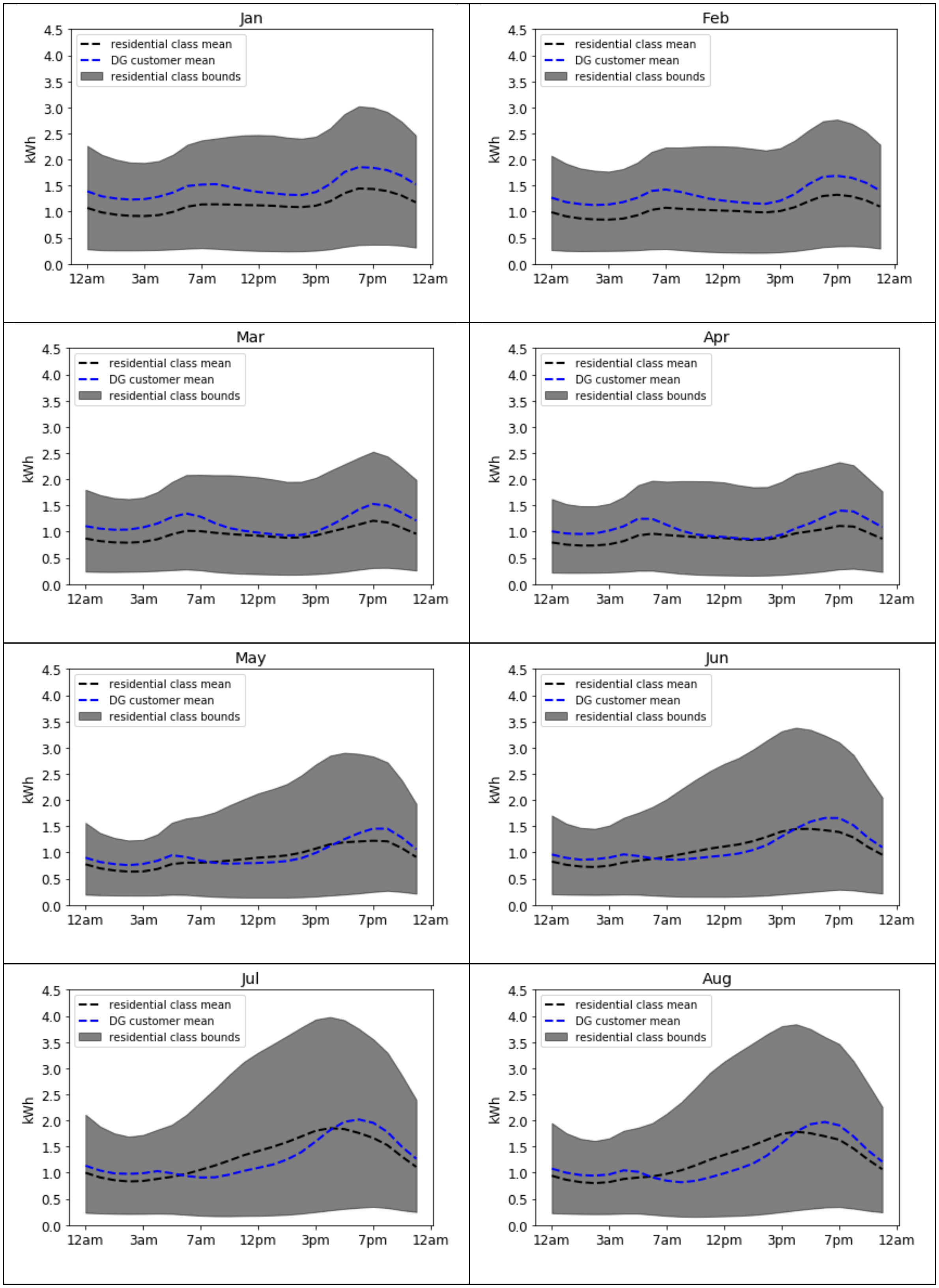
Mr. Lucas calculated an appropriate outflow credit rate that he recommends be applied as the outflow credit. He offered two methodologies for calculating an appropriate COSS based outflow credit that reflects the value of outflow from NEM customers based on the times that they are providing energy to the grid. The recommended outflow credit reflects the value of outflow in the cost of service study using data that has not heretofore been utilized by the Commission or the Company. Mr. Lucas calculates the appropriate credit rate of $0.23957/kWh, plus an adder for reduced cost of service, as recommended in his testimony.

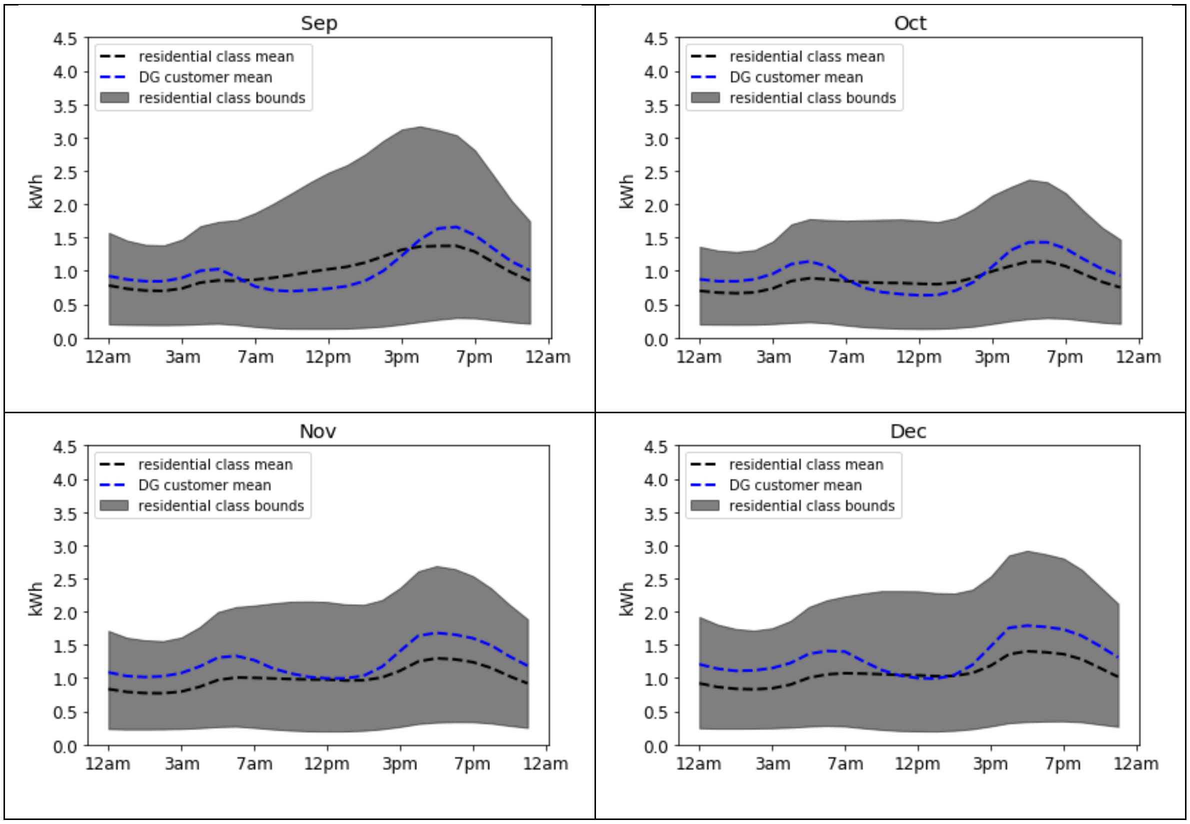
B. *<u>Testimony of Claudine Custodio</u>*

Q: Please describe the testimony of Ms. Custodio.

A: Ms. Custodio presents the results of analysis that she has performed of the residential customer load data and data on the inflow and outflow of existing net energy metering customers, both of which data sets were provided by the Company in response to data requests. Ms. Custodio performed analysis of these data sets to understand the types of customers within the general residential rate class and the impact of residential distributed generation customers on the rate class and within the rate class. Her analysis shows that within the residential rate class, there are several statistically identifiable clusters of load shapes (customer types). She also compared the DG customers to the rest of the residential customer class to understand how DG customers fit within the class. Her analysis showed several interesting findings. First, when compared to the other customer types within the class, residential distributed generation customers as a group fall well within the range of variability within the residential class. Figure 1 of Ms. Custodio's testimony (shown here also as Figure 1) shows that residential DG customers' monthly average load shapes are similar fall well within the residential class bounds (the middle 80^{th} percent) in every month.

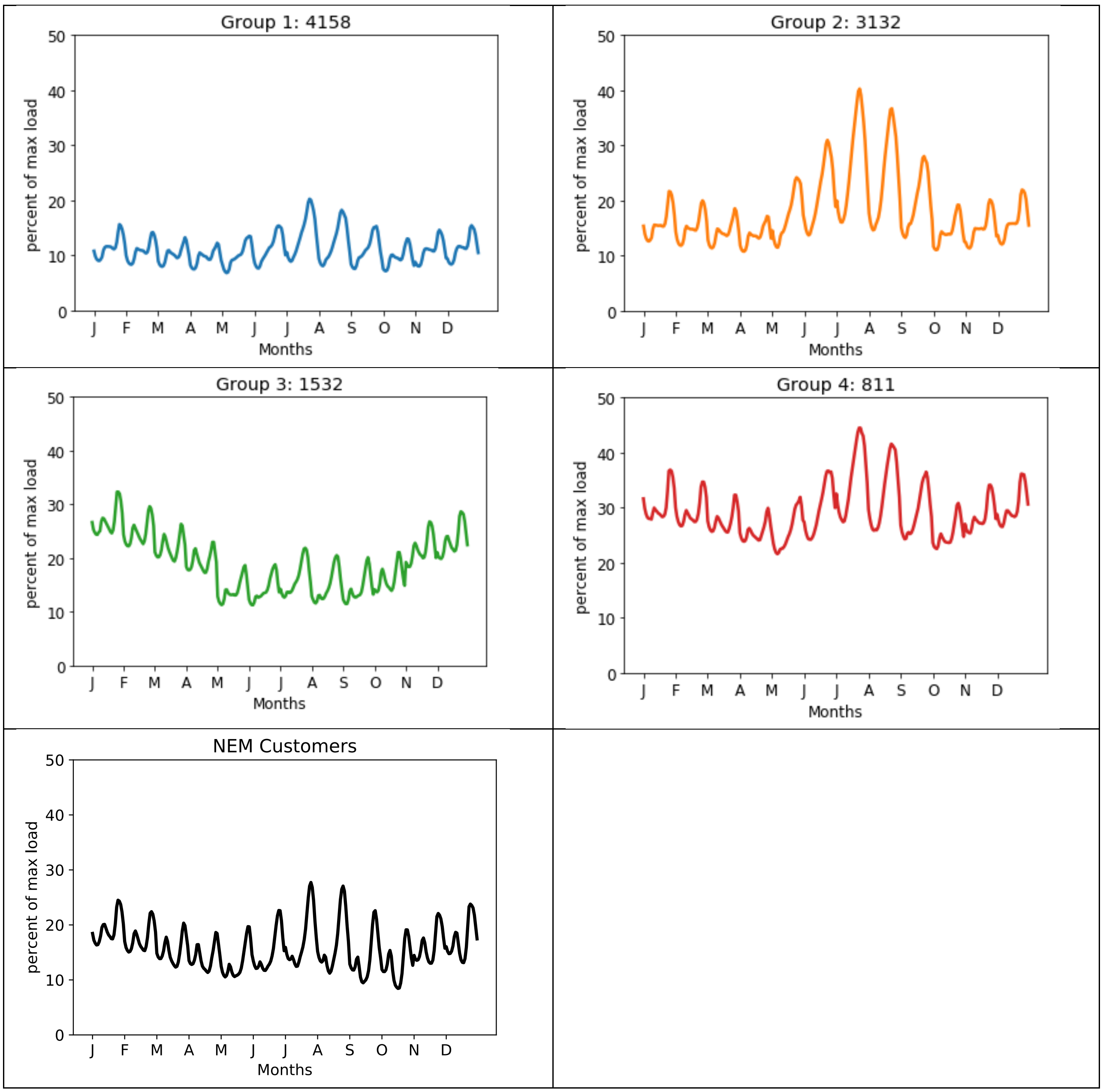
Figure 1 Electricity Use Profile of Residential Customer Class





Another important finding of Ms. Custodio's testimony shows that to the extent to which they do vary from the class, residential DG customers contribute diversity to the class. Ms. Custodio's analysis of the class load data showed four distinct clusters of types of customers in the residential load class. Figure 6 of Ms. Custodio's testimony (shown here as Figure 2) clearly illustrates these distinct monthly load shapes. For example, Group 1 shows a low monthly usage profile that is fairly consistent in each month. Group 2 is characterized by relatively flat load shapes during the winter, spring and fall, but very large average daily spikes in the summer, indicative of heavy summer air conditioning loads. On the other side of the spectrum is Group 3, which consists of winter peaking customers that likely heat their homes with electric heat. Group 4 are much higher use customers who also have considerably higher total use and also exhibit characteristics of air conditioner loading in the summer. Finally, the NEM population data has been shown in a similar normalized fashion here (although it is population data and not sample data) for illustrative purposes. In the context of the other clusters, this visualization illustrates again that NEM customers are within the range of variability within the class and contribute to diversity within the class.

Figure 2 Load Shapes Resulting from Cluster Analysis



Q: What do you conclude about the findings of Ms. Custodio's testimony?

A: The results and conclusions of Ms. Custodio's study demonstrate that considerable diversity exists within the residential class. There are several distinct groups of customers larger than the group of rooftop solar customers with highly varying load shapes that could have potential implications for cost recovery. By contributing to the diversity in the rate class, residential DG customers provide considerable value to the class above and beyond the value of their outflow (discussed elsewhere by other JCEO witnesses).

C. *Testimony of Dr. Gabe Chan*

Q: Please describe the testimony of Dr. Chan.

A: Dr. Chan brings two important perspectives to this proceeding. First, Dr. Chan has been participating in the development of the Value of Solar docket in Minnesota for a number of years. Second, Dr. Chan's research has been focused on the social costs of energy production.

Dr. Chan describes elements of the Minnesota Value of Solar proceedings and what elements of the process to develop the Value of Solar methodology in Minnesota could be relevant to a full and fair valuation of solar energy for Michigan ratepayers. He explains the methodology used to calculate the VOS and explains the evolution and implementation of the methodology.

Dr. Chan then explains the policy and economic underpinnings of the VOS policy. He explains, "A Value of Solar framework best approaches compensating DG customers based on their 'fair and equitable use of the grid." (Chan at 23) Dr. Chan also explains how a properly designed VOS mechanism prevents all net cross-subsidization. By ensuring that DG customers are fairly compensated, the Company and non-participants are paying the full and fair value for the distributed generation that is put onto the system by DG customers.

Dr. Chan discusses how unpriced externalities create cross-subsidies for the utility. This has been an issue in Michigan before, but the Commission should revisit the question in light of the finding in the DTE IRP that environmental costs can be considered in the context of compliance with the Michigan Environmental Protection Act. Dr. Chan also acknowledges the difficulties of conducting the calculations of the Value of Solar, but goes on to explain that ignoring value because it is hard to calculate is not just and reasonable. Ignoring values creates unpriced externalities that distort the system.

D. *<u>Testimony of Karl R. Rábago</u>*

Q: Please describe the testimony of Mr. Rábago.

A: Mr. Rábago describes the regulatory theory underpinning the compensation of distributed generation and compares it to the statutory and regulatory framework in Michigan.

He explains how the principles for public utility ratemaking articulated by James Bonbright apply to the distributed generation compensation. He then proceeds to relate Bonbright's principles to the full and fair valuation of distributed generation in Michigan.

Mr. Rábago reviews the statutory and procedural background of the Distributed Generation Tariff and supports the Commission's previous finding that it has broad authority to require a tariff that would fully and fairly value distributed generation. Based on a review of the implementation of the DG Program, Mr. Rábago recommends that the Commission should undertake a comprehensive value of solar study in view of the fact that the Commission, the utilities and stakeholders now have more data and experience with distributed generation and are well positioned to provide full and fair value for DG outflow.

Mr. Rábago also explains the negative impacts that an unreasonably low outflow rate would have not only on potential DG customers, but on non-participants by depriving them of the benefits of distributed generation as well.

Mr. Rábago also finds that the Company's assertions that DG customers avoid paying their fair share of system costs lack credible evidence and should be dismissed. The Company has failed to provide any evidence to support a just and reasonable quantification and treatment of any such cost shifts or to demonstrate in any meaningful way the potential cost shifts are sufficiently significant to justify adjustment through the DG Program.

Mr. Rábago also examines the environmental impairment that could be caused by the Company's proposed DG Program. If the Company's proposed tariff would disincentivize the optimal amount of distributed generation in the service territory, that would have an adverse impact on the environment. As such, Section 1705(1) of the Michigan Environmental Protection Act ("MEPA")[20] would apply.

Mr. Rábago explains why customers choosing to reduce their energy use through distributed energy resources do not "cause" costs. He further explains how the Company's assertion that DG customers should be forced to pay for costs that they do not create is based on a "false conflation" of sunk costs and fixed costs. "Charging (or decrementing the outflow credit) because DG customers use less energy than they would

[20] MCL 324.1705(1)

have without DG or less energy than an average customer in the class, in the absence of cost of service data based on actual costs and usage, is discriminatory, punitive, and economically inefficient."

Mr. Rábago summarizes a number of studies citing the benefits of distributed generation to the grid and showing that studies have shown that, if anything, distributed generation customers provide more value to the grid than they receive, even under full net metering regimes.

Mr. Rábago provides a critique of the Brattle Group report that explains the deficiencies in the methodologies and calculations that lead to the erroneous conclusion that DG customers cost more to serve than other customers. In fact, Mr. Rábago claims that "In all, the Brattle report, even though founded on flawed and estimated data, paints a compelling picture of system- and class-wide benefits accruing in the cost to serve DG customers." Mr. Rábago explains why the methodology of the Brattle report produces non-sensical results that cannot then be relied upon to inform any conclusions about the cost to serve DG customers.

Mr. Rábago explains the value of load diversity and how DG customers contribute to load diversity, thus reducing costs for the class.

Mr. Rábago then explains the deficiencies in the analysis that lead to the Company's proposed outflow credit. He finds that the Company offers no credible evidence demonstrating that either the inflow charge or the outflow credit is based on analysis of cost of service or value of exported energy.

Mr. Rábago cites to previous Commission determinations about the applicability of certain sections of governing statutes to show that the basis for the Company's exclusion of transmission and distribution costs is not supported by statute or Commission precedent, and therefore is unjust and unreasonable.

E. *Testimony of Ronny Sandoval*

Q: Please describe the testimony of Mr. Sandoval

A: Mr. Sandoval addresses the value of distributed generation to the distribution grid. He describes a number of value streams that DG provides to the distribution system. Despite this, Mr. Sandoval finds that it does not appear that the Company has evaluated the distribution system benefits of DG in any thorough or systematic manner. The failure to identify and quantify those benefits then informs the Company's proposal to offer no outflow credit to DG customers for their value to the distribution system.

Mr. Sandoval recommends that the Commission direct the Company to include, as a part of its compensation to DG customers, compensation for the value of distributed generation to the distribution grid. He also recommends that the Commission further investigate the value of DG to the distribution system as a part of the Value of Solar study that JCEO witnesses Rábago and Chan describe in more detail. Finally, Mr. Sandoval recommends that the Company leverage its distribution system planning process to inform its full and fair valuation of DG (and DER more generally) to the distribution system.

Mr. Sandoval also responds to testimony regarding the Company's distribution planning process and grid modernization strategy. He explains the interaction between the proposed Distributed Generation Program and other utility processes such as distribution planning and grid modernization. Finally, Mr. Sandoval addresses specific components of the Company's broader grid modernization strategy—its proposed battery storage pilots, and its proposed investment in conservation voltage reduction ("CVR").

Mr. Sandoval explains how the principles of Integrated Distribution Planning ("IDP") should be applied to ensure that customers benefit from the extensive distribution system investments proposed by the Company in this case.

Mr. Sandoval explains how DERs may be aggregated to work in concert as a "virtual power plant" ("VPP") and can be used to provide a number of energy and ancillary services.

Mr. Sandoval proposes a framework for valuing DER on the grid. Distribution system planning often involves a "Grid Needs Assessment" that identifies potential shortfalls in the planning horizon across required grid services. As these grid needs become more transparent through stakeholder processes or other forums, DER portfolios and other innovative offerings could be considered viable solutions to fill these requirements. These DER services could then be valued based on their ability to meet these needs.

Mr. Sandoval critiques the Company's proposal to deploy DERMS. Importantly, for example, he explained that in discovery response 20697-ELPC-CE-126, the Company provided a description on how DERMS investments would operate by indicating it would "use DERMS to control the voltage, power factor, real power, and reactive power settings of DERs." However, the Company did not provide specifics at this time on how it would compensate DER sites for these additional services to the grid they would provide.

Mr. Sandoval also addresses the Company's Conservation Voltage Reduction program. He finds the Company's CVR plan to be very promising but notes that it should further explore the opportunities to use tools developed in the CVR program to actively manage dynamic system conditions.

VI. DISTRIBUTED GENERATION PARTICIPATION MINIMUM LEVELS

Q: What minimum distributed generation program limits apply to the proposed Distributed Generation Program?

A: Section 173 of PA 342 requires utilities to allow at least 1 percent (1%) of the electric utility's average in-state peak load for the preceding five years to participate in distributed generation programs.[21] The 1% requirement includes three subgroups:

- 0.5% for customers with a distributed generation project of 20 kilowatts or less.
- 0.25% for customers with a distributed generation project of between 20 and 150 kilowatts.
- 0.25% for customers with a methane digester of 150 kilowatts or more.

While this is often characterized as a cap on participation in distributed generation, it is important to note that it is in fact a minimum participation level which the utility must allow. There is no limitation in the statute on the utilities' ability to extend participation beyond the minimum.

Q: How close is Consumers Energy to hitting the 1% DG minimum limits?

[21] MCL 460.1173.

A: According to responses to discovery by MEIBC, Consumers Energy is very close to reaching the limits for both Category 1 and Category 2. Rows 1-3 of the table below summarize information from U20697-MEIBC-CE-198, U20697-MEIBC-CE-199 and U20697-MEIBC-CE-200, provided as Exhibits CEO-2 (WDK-2) , CEO-3 (WDK-3), and CEO-4 (WDK-4). Row 4 of the table shows the average rate at which applications have been submitted to the Company over the 11-month period through February of this year.[22]

Table 2: Distributed Generation Program Minimum Capacity

Row Number	Item	Category 1	Category 2	Category 3
1	Currently Applicable Minimum	36,405 kW	18,203 kW	18,203 kW
2	Current Installed Capacity	25,433 kW	11,152 kW	190 kW
3	Capacity Remaining	10,972 kW	7,051 kW	18,013 kW
4	Average applications per month (through February 2020)	1,045 kW	538 kW	0 kW

This data illustrates that the Company is very close to reaching its voluntary minimum participation level for Category 1. In response to another question, the Company indicated that although the COVID-19 pandemic has complicated the forecast of when the required capacity under the existing limits would be reached, they estimate that the 0.5% capacity in Category 1 could be reached in October 2020 and by the end of 2021 for Category 2.[23]

[22] Although the Company provided data for April and March of 2020 in its discovery responses, they were excluded from this calculation because of COVID.
[23] U20697-MEIBC-CE-202 submitted as Exhibit CEO-5 (WDK-5)

Q: What will happen after the DG program minimum participation limit is reached?

A: According to the Company Witness Hubert Miller, "the Company is proposing to maintain the current caps on the amount of excess power it will purchase at above market prices."[24] Assuming that the Company does not choose to voluntarily extend the DG Program beyond the voluntary statutory limits, Miller explains that customers could participate in one of two ways:

> [A] customer with eligible generation will have the option to sell their excess power to the Company at the standard offer Public Utility Regulatory Policies Act of 1978 ("PURPA") rate. Qualifying customers who are not interested in the standard offer PURPA rate may also be eligible to sell their excess power to the Company at the market price of energy described in Rule C11 of the proposed tariffs in this case.[25]

Q: What is the Rule C11 that Mr. Miller references as an option?

A: The Company proposes a new Rule C11.1 Self-Generation in this case. According to the proposed new rule, the Self-Generation tariff would be open to customers who meet the Federal Energy Regulatory Commission's ("FERC") criteria for a Qualifying Facility, but elect not to participate in the Company's Standard Offer under Rule C18, Distributed Generation Program, or Net Metering Program. Under this program, the Company proposes the following energy purchase terms:

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[24] Direct Testimony of Hubert Miller, pg. 25.
[25] Miller, pg. 26.

> An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's, Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule). The Company may discontinue purchases during system emergencies, maintenance, and other operational circumstances.[26]

The proposed energy purchase price does not include any compensation beyond the market value of energy.

Q: Given the option to participate in the Company's Standard Offer Contract under PURPA, would you expect DG customers to elect to participate in this program?

A: No. While excessively burdensome for residential customers, they would receive a somewhat higher compensation by participating in the Standard Offer Contract. Under Rule C18, customer QFs at or below 150kWAC are eligible to receive a power purchase agreement based on the Company's full avoided cost rates, regardless of the Company's capacity need, for the maximum term provided for full avoided costs.[27]

Q: How would this be implemented for a residential customer?

A: Residential customer participation in the PURPA Standard Offer would require customers to sign power purchase agreements with the Company that were intended to be applicable to the interactions between the Company and developers of large qualifying facilities. In addition, because the full avoided cost rates are based on LMP for energy

[26] Company Exhibit No: A-16(RLB-2), Schedule F-5, Page 15 of 135.
[27] Company's current electric ratebook. Fourth Revised Sheet No. C-59.00.

and monthly payments for capacity based on the PRA, they lack transparency and predictability for residential customers.

On the Company side, the Company would be required to execute and administer qualifying facilities contracts with each individual customer independent of their existing customer relationship with the Company. The Company would be required to administer monthly invoicing and payments to customers under the existing Standard Offer contract.

Q: What options does the Company have to avoid this situation?

A: Based on this burdensome process, I conclude that it would be far preferable for the Company to voluntarily offer the DG Program (as amended to fairly compensate outflow pursuant to the recommendations of JCEO witnesses) to all customers. JCEO Witness Dr. Chan and others explain that if properly priced, there would be no cross-subsidization because the outflow would be valued at the Company's true, actual cost. Thus, if the Commission requires the Company to set outflow rates for the DG Program at the appropriate fair value of distributed generation, the Company should be truly indifferent to the level of distributed generation. As such, there should be no ratemaking issue associated with extending eligibility for DG Program participation.

VII. RECOMMENDED CHANGES TO THE DG PROGRAM

Q: What do you recommend with respect to the proposed tariffs implementing the Company's Rule C11 Self-Generation, Net Metering and Distributed Generation?

A: The JCEO make the following recommendations related to Rule C11: Self-Generation, Net Metering and Distributed Generation[28]:

- In *Rule C11.1 Self-Generation*, the Energy Purchase price should be the same rate as the Company's PURPA Standard Offer set in *Rule C18 – Standard Offer – Purchased Power*. However, this proposed new rate would not be needed at all if the Company offers the DG Program to customers beyond the 1% cap.
- In Rule C11.3.A, the reference should be corrected to refer to provisions in Public Act 342.
- Proposed Rule C11.3.B.7 regarding the program caps should be deleted. As discussed above and in the testimony of CEO Witnesses Rábago, Chan, and Lucas, a properly set outflow rate should alleviate concerns about impacts on the Company and non-participating customers. As such the Company should voluntarily agree to remove the caps on distributed generation. Changes to C11.3.C would also be required to effectuate this.
- Proposed *Rule C11.3.E.2 Customer Billing – Outflow Credit* should be revised to read:

> The customer will be credited on Outflow for the billing period or time-based pricing period. The credit shall be applied to the current billing month and shall be used to offset charges on that bill. Any excess credit not used will be carried forward to subsequent billing periods. Unused

[28] Proposed Tariff Sheets included in Exhibit No: A-16 (RLB-2), Schedule F-5, Pages 14-30.

Outflow Credit from previous months will be applied to charges in the current billing month, if applicable. Outflow credit is non-transferable.

- Proposed *Rule C11.3.E.a Full Service Customers Outflow Credits* should be revised to reflect the recommendations of JCEO Witness Lucas to reflect the full value of outflow as reflected in the cost of service study as described in Mr. Lucas' testimony.

Q: What do you recommend with respect to review and revision of the methodology for the Inflow/Outflow methodology?

A: Consistent with the testimony of JCEO witnesses Rábago, Chan, Sandoval, Lucas, and Custodio, the time has come for the Commission to conduct an analysis of the full and fair value of the outflow from distributed generation customers. Specifically, we recommend that the Commission direct Staff to lead stakeholders in the development of a framework for a comprehensive Value of Solar analysis for Michigan that clearly guides assessment of the "fair and equitable use of the electric grid" as inclusive of all benefits to ratepayers, the utility, and society—including environmental benefits. The understanding of fair and equitable use must include consideration of the full range of benefits that the customer-generated power provides to the grid and to non-participants.

VIII. SUMMARY AND CONCLUSIONS

Q: Please summarize your findings and recommendations?

A: Taken as a whole, the testimony of Joint Clean Energy Organizations witnesses provides a clear case that the Company's proposed Distributed Generation Tariff fails to provide a just and reasonable framework for distributed generation customers. In particular, the outflow credit rate is not just and reasonable, nor is it cost-based, in the sense that the credit is calculated based on a fair application of the Company's Cost of Service Study methodology.

The JCEO demonstrate that distributed generation provides significant uncompensated value that can be measured. Ever since the Commission's Order in U-18383, the Commission has indicated its intent to revisit the question of outflow credit when sufficient experience and information has accumulated. The JCEO have shown that the Commission, the Company and stakeholders now have sufficient information and experience to conduct such a study.

The JCEO recommend that the Commission require the Company to adopt an outflow credit based on COSS principles consistent with the methodology proposed by Mr. Lucas. In addition, the JCEO recommend that the Commission initiate a comprehensive Value of Solar proceeding with the goal of setting an outflow credit methodology that fully and fairly values outflow at the time at which it is provided to the system.

Q: Does this conclude your testimony?

A: Yes, it does.

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-20697
generation and distribution of electricity	)	
and for other relief.	)	

DIRECT TESTIMONY

OF

KEVIN LUCAS

ON BEHALF OF

THE ECOLOGY CENTER, ENVIRONMENTAL LAW & POLICY CENTER, GREAT LAKES RENEWABLE ENERGY ASSOCIATION, SOLAR ENERGY INDUSTRIES ASSOCIATION, AND VOTE SOLAR

JUNE 24, 2020

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I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is Kevin Lucas. I am the Director of Rate Design at the Solar Energy Industries Association (SEIA). My business address is 1425 K St. NW #1000, Washington, DC 20005.

Q. PLEASE SUMMARIZE YOUR BUSINESS AND EDUCATIONAL BACKGROUND.

A. I began my employment at SEIA in April 2017 as the Director of Rate Design. SEIA is leading the transformation to a clean energy economy, creating the framework for solar to achieve 20% of U.S. electricity generation by 2030. SEIA works with its 1,000 member companies and other strategic partners to fight for policies that create jobs in every community and shape fair market rules that promote competition and the growth of reliable, low-cost solar power. Founded in 1974, SEIA is a national trade association building a comprehensive vision for the Solar+Decade through research, education, and advocacy.

As Director of Rate Design, I work with other members of SEIA's State Affairs team to engage in various regulatory dockets. I have developed testimony in rate cases on rate design and cost allocation, in integrated resource plans on resource selection and portfolio analysis, worked on the New York Reforming the Energy Vision proceeding on rate design and distributed generation compensation mechanisms, and performed a variety of analyses for internal and external stakeholders.

Before I joined SEIA, I was Vice President of Research for the Alliance to Save Energy (Alliance) from 2016 to 2017, a DC-based nonprofit focused on promoting technology-neutral, bipartisan policy solutions for energy efficiency in the built environment. In my role at the Alliance, I co-led the Alliance's Rate Design Initiative, a working group that consisted of a broad array of utility companies and energy efficiency products and service providers that was seeking mutually beneficial rate design solutions. Additionally, I performed general analysis and research related to state and federal policies that impacted energy efficiency (such as building codes and appliance standards) and domestic and international forecasts of energy productivity.

Prior to my work with the Alliance, I was Division Director of Policy, Planning, and Analysis at the Maryland Energy Administration, the state energy office of Maryland, where I worked between 2010 and 2015. In that role, I oversaw policy development and implementation in areas such as renewable energy, energy efficiency, and greenhouse gas reductions. I developed and presented before the Maryland General Assembly bill analyses and testimony on energy and environmental matters, and developed and presented testimony before the Maryland Public Service Commission on numerous regulatory matters.

I received a Master's degree in Business Administration from the Kenan-Flagler Business School at the University Of North Carolina, Chapel Hill, with a concentration in Sustainable Enterprise and Entrepreneurship in 2009. I also received a Bachelor of Science in Mechanical Engineering, cum laude, from Princeton University in 1998.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION?

A. Yes. I have submitted multiple rounds of testimony in Cases U-18419 (DTE's 2017 CON proceeding),[1] U-20162 (DTE's rate case implementing the inflow/outflow DG PV methodology),[2] U-20165 (Consumers Energy's 2018 IRP proceeding),[3] and U-20471 (DTE's 2019 IRP proceeding).[4]

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE OTHER STATE UTILITY COMMISSIONS?

A. Yes. I have testified before the Maryland Public Service Commission in several rate cases and merger proceedings. Additionally, I have testified before the Maryland Public Service

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[1] *In the matter of the application of DTE Electric Company for approval of Certificates of Necessity pursuant to MCL 460.6s, as amended, in connection with the addition of a natural gas combined cycle generating facility to its generation fleet and for related accounting and ratemaking authorizations.*

[2] *In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.*

[3] *In the matter of the application of Consumers Energy Company for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief.*

[4] I*n the matter of the application of DTE Electric Company for approval of its integrated resource plan pursuant to MCL 460.6t, and for other relief.*

Commission in several rulemaking proceedings, technical conferences, and legislative-style panels, covering topics such as net metering, EmPOWER Maryland (Maryland's energy efficiency resource standard), and offshore wind regulation development.

I have also submitted testimony before the Public Utility Commission of Texas, the Public Utility Commission of Nevada, and the Colorado Public Utilities Commission. My complete CV is attached to my testimony.[5]

Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A. I am submitting testimony on behalf of the Ecology Center, the Environmental Law & Policy Center, the Great Lakes Renewable Energy Association, the Solar Energy Industries Association, and Vote Solar, collectively the Joint Clean Energy Organizations ("JCEO").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony focuses on the cost-of-service characteristics of residential net energy metered ("NEM") customers compared to non-NEM residential customers. I want to be clear that when I refer to NEM customers, I am not referring to the specific net metering rate design authorized under prior Michigan statutes. Rather, I am discussing a comparison between distributed generation customers and non-distributed generation customers, who are by necessity compared using data that is netted on an hourly basis. Any customer who self-generates energy I consider to be a NEM customer, regardless of the rate design under which that customer is treated. I begin by evaluating and critiquing the Brattle Group's study on these NEM customers and show that bad source data combined with errors and misleading presentations of the results justify setting aside the report's conclusions. I then discuss the proper treatment of outflow energy in the class cost of service study ("CCOSS") before presenting my own analysis of the cost to serve NEM customers using a much cleaner data set and properly adjusting the Company's CCOSS model. Finally, I calculate an alternative outflow rate credit derived from the CCOSS model.

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[5] Attachment CEO-6 (KL-1), Kevin M. Lucas CV.

Q. PLEASE SUMMARIZE YOUR FINDINGS.

A. The source and quality of data considered is very important. When evaluating proper data. NEM customers are actually less costly to serve than non-NEM customers. The Brattle study upon which the Company relies to show the cost of service of NEM customers should be disregarded. The Brattle study's source data (that the Company provided) was substantially incomplete and required much data processing. Even after cleaning, the data was starkly different than an updated version of the NEM customer data. Brattle improperly adjusted the Company's CCOSS model, and ultimately presented its results in a manner inconsistent with either the CCOSS or retail rate designs.

The Company cannot substitute the proper treatment of outflow energy in the CCOSS by proposing an arbitrary outflow credit. Outflow energy should be included in the CCOSS because it legitimately reduces the load of the entire residential class during critical load hours. The Company's failure to do so penalizes the residential class as a whole by overstating the residential class's load, and thus share of costs, which is derived from those critical load hours.

Using updated NEM customer data and a properly adjusted CCOSS, I used the Company's own CCOSS model to demonstrate the cost to serve the average NEM customer was roughly $0.03 / kWh to $0.035 / kWh *less* than for the average non-NEM customer. I also show that NEM customers are less expensive to serve than similarly-sized non-NEM customers, largely due to the meaningful reduction in load during the key hours that are used to allocate costs.

Finally, I calculated an updated outflow credit based on the CCOSS model using two methods. The first method models the outflow load profile in the CCOSS, while the second maps cost by allocator to energy TOU periods. I also posit that an adder that is conceptually similar to critical peak pricing that should be included in the outflow rate. Using the TOU period mapping method, I calculate an appropriate credit rate of $0.23957 / kWh, with an adder that ranges between $0.02739 / kWh and $0.05341 / kWh depending on the 4CP method and treatment of outflow energy in the CCOSS.

I recommend the Commission recognize the benefits that NEM customers bring to the entire residential class through proper treatment of outflow energy in the CCOSS, and encourage the establishment of a cost-based outflow credit that reflects the value this energy provides. This will send a more appropriate cost-based price signal to prospective NEM customers until a Value of Solar study is complete and the Commission establishes compensation based on such study.

II. THE COMMISSION SHOULD REJECT THE BRATTLE GROUP'S CONCLUSIONS ON NEM CUSTOMERS

Q. PLEASE PROVIDE AN OVERVIEW OF THIS SECTION OF YOUR TESTIMONY.

A. In this section, I discuss the study that The Brattle Group ("Brattle") performed for the Company related to the cost to provide service to residential,[6] commercial,[7] and standby customers.[8] I focus on the residential analysis, and discuss some of the challenges that Brattle had given the underlying quality of the data provided by the Company.

Q. WHAT ARE YOUR PRIMARY CONCLUSIONS?

A. The Commission should reject in its entirety Brattle's conclusions that the cost to serve "residential customers with DG ranges between 20% to 50% more than that of other customers".[9] As a primary matter, it is inappropriate to model NEM customers as their own class in a CCOSS model. This conclusion is supported by the findings of expert witness Claudine Custodio's testimony, at Brattle's statistical analysis on the distinction between NEM and non-NEM customers is undermined by the ease of producing "stronger" results between very similar groups of customers. Additionally, Brattle's study is plagued by data issues, and while it attempted to overcome these severe limitations, its results are simply not credible given the updated NEM data the Company has provided in discovery. Further, independent of the poor quality of the data on which it relied, Brattle made several questionable assumptions, and ultimately presented its results in a misleading manner that does not provide an accurate assessment of the costs of serving DG customers. In the latter section of my testimony, I use the Company's updated data to demonstrate that, contrary to Brattle's conclusions, NEM customers are in fact less expensive to serve than non-NEM customers.

Q. PLEASE PROVIDE AN OVERVIEW OF THE BRATTLE RESIDENTIAL NEM STUDY.

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6 CONFIDENTIAL attachment CEO-7 (KL-2), Brattle Res NEM U20697-ELPC-CE-110-Aponte_ATT_1.pdf ("Brattle Residential NEM Report.")
7 CONFIDENTIAL attachment CEO-8 (KL-3), Brattle Sec NEM U20697-ELPC-CE-110-Aponte_ATT_2.pdf
8 Exhibit No. A-21.
9 Miller Direct at 26-27.

A. Brattle's residential NEM study analyzed whether it was appropriate to model residential NEM customers as a separate cost of service class, and then used the Company's CCOSS model to calculate the cost of serving NEM customers as if they were a separate cost of service class. Brattle first calculated load metrics such as average per capita energy usage and demand and analyzed the differences between NEM and non-NEM customers. In an analysis limited to just these two customers groupings, it claimed that there were significant differences between the two groups and proceeded to model each group separately in the Company's CCOSS model.

Brattle began this stage of its analysis by taking hourly inflow data from NEM customers for 2018. After substantial data processing to account for missing data at both the customer and hour level, Brattle compared key load characteristics such as energy usage, non-coincident peak ("NCP") demand, coincident peak ("CP") demand, and load factor, and claimed that "residential NEM customer inflow patterns appear to be significantly different from non-NEM residential customer consumption patterns."[10] As I explain later, this conclusion was incorrect.

From that point, Brattle calculated the total cost allocated to residential NEM customers separately from residential non-NEM customers using the Company's CCOSS model. Based on the total costs allocated in the model, Brattle concluded that the unitized cost to serve residential NEM customers was higher than non-NEM customers. Table 1 below duplicates these results.[11]

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[10] Brattle Residential NEM Report at 12.
[11] Brattle Residential NEM Report at 15.

Cost Type	**Brattle Measure**	**Non-NEM**	**NEM**
Production			
Net Capacity Cost	$/kW CP	$150	$202
Capacity-Related Cost Offset	$/kW CP	$78	$162
Non-Capacity-Related Costs	$/kWh	$0.043	$0.042
Distribution			
Demand-Related Cost	$/kW NCP	$165	$181
Customer-Related Cost	$/Customer	$88	$88

Table 1 - Brattle Residential NEM Customer Costs

Q. DID THE BRATTLE STUDY CONSIDER OUTFLOW ENERGY?

A. No. The outflow energy, and all value that it represented, was out of scope. Brattle focused only on the inflow energy. While I discuss outflow energy later in my testimony, Brattle's decision to ignore outflow further limits the usefulness of the Brattle report. The Brattle Report only addresses one component of the analysis necessary to determine the value of a NEM customer – a value which other witnesses such as Gabriel Chan and Karl Rábago discuss in their testimony with respect to distributed generation customers.

Q. DID YOU ANALYZE BRATTLE'S STUDY ON COMMERCIAL NEM CUSTOMERS?

A. I did not analyze the commercial NEM study in the same level of detail, because I did not find it relevant to the DG Tariff. However, based on Brattle's presentation and workpapers, Brattle's commercial analysis followed a similar process for these customers as it did with the residential customers. It also appears that similar data issues, requiring modification of the underlying NEM load data, affected Brattle's commercial NEM study. Finally, Brattle points out that it is unclear what class commercial NEM customers should be placed in under the Company's CCOSS. Curiously, it does not present a conclusion regarding the relative cost to serve these customers.[12] For the remainder of my testimony, any references to the Brattle study apply to the residential analysis only, and not to the commercial analysis.

[12] Attachment CEO-8 (KL-3), Brattle Sec NEM U20697-ELPC-CE-110-Aponte_ATT_2.pdf

A. Brattle's Analysis of the Difference Between Residential NEM and Non-NEM Customers should be Disregarded

Q. PLEASE DESCRIBE THE ANALYSIS THAT BRATTLE PERFORMED TO DETERMINE HOW SIMILAR OR DISSIMILAR NEM AND NON-NEM CUSTOMERS WERE.

A. Brattle performed a very basic analysis on the monthly per capita average values of five metrics: energy, CP, NCP, average demand, and load factor. Two of these (average demand and load factor) are simply mathematical derivatives of the others and should not be considered unique metrics.[13] Taking the remaining three metrics, Brattle performed a "two-tailed paired sample t-test" to determine the likelihood that the average per capita monthly values for the NEM and non-NEM customers were the same across all months.[14] In its analysis, Brattle determined the t-test for energy and NCP demand were statistically significant and found the t-test for the CP was not statistically significant.[15] This means that any conclusions Brattle reached regarding energy and NCP demand were reasonably within the realm of possibility, whereas there was not sufficient statistical evidence to be able to rely upon conclusions regarding the CP.

Brattle also analyzed the timing of the monthly NCP demand, comparing the hours in which the system, residential class, and NEM customers peaked. It found "no obvious pattern" between these values.[16] Finally, it analyzed the hourly load shape for January and July during the day when the system reached its peak in those months, concluding that NEM customer inflow "dip[s] in the middle of the day and delays the NEM peak hour."[17] From these analyses, Brattle concludes that "residential NEM customer inflow patterns appear to be significantly different from non-NEM residential customers consumption patterns."[18]

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[13] Average demand is mathematically equivalent to monthly energy divided by number of hours in a month, and load factor is mathematically equivalent to energy divided by NCP divided by hours in a month. A statistical analysis on these two derived metrics provides no additional insight.
[14] Brattle Residential NEM Report at 8-9.
[15] The p-values for energy, NCP, and CP t-tests were 0.022180, 0.000001, and 0.945099, respectively. The first two are statistically significant at the 0.05 level.
[16] Brattle Residential NEM Report at 10.
[17] Brattle Residential NEM Report at 11.
[18] Brattle Residential NEM Report at 11.

Q. DO YOU AGREE WITH THESE RESULTS?

A. I do not disagree with the mathematical results of Brattle's t-test analysis. However, I do not believe these results produce a meaningful result that supports treatment of NEM customers as s separate class in the CCOSS model.

Q. WHY DON'T YOU THINK THE RESULTS CAN BE USED TO SUPPORT TREATMENT OF NEM CUSTOMERS AS A SEPARATE CLASS?

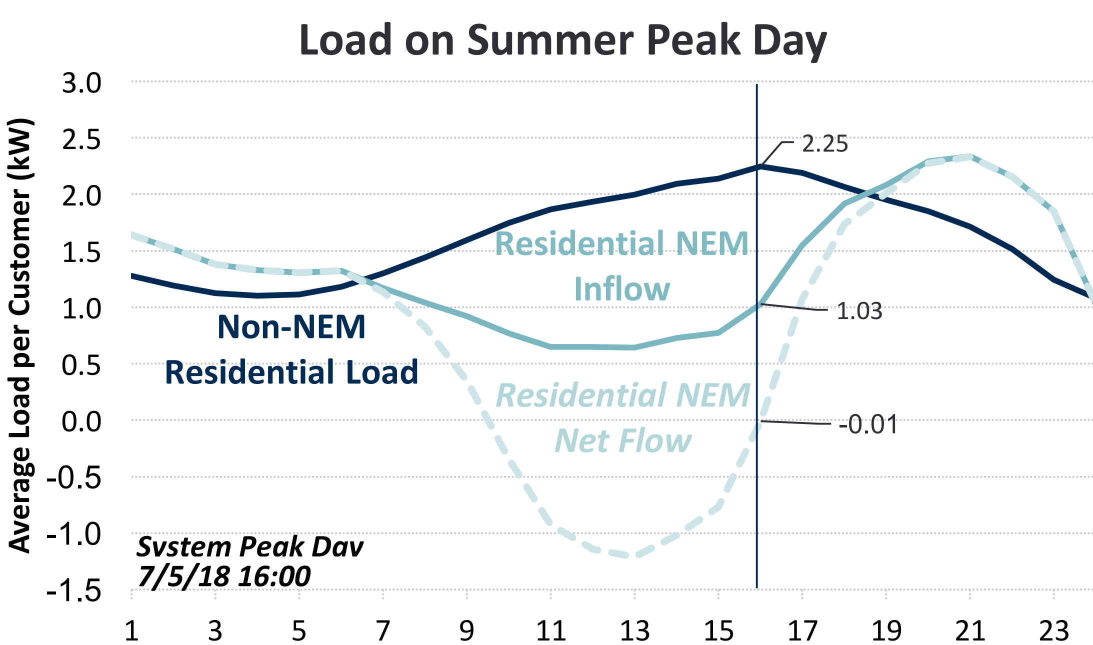
A. As a predicate, it is worth pointing out that in Brattle's analysis, NEM customers represent only 1,654 customers out of the Company's 1,606,159 total residential customers, a paltry 0.1%. NEM customer demand during the 2018 system peak hour was just 1.25 MW, only 0.035% of the residential class load of 3,601 MW.[19] Essentially, NEM customers are a rounding error when it comes to the residential class. In this proceeding, the Company is planning to increase the revenue collected from the residential class by $280,236,119 *per year,* equal to an astounding $14.41 per customer in higher bills each month. Meanwhile, if the entire NEM class was given free service (which I am not proposing), the impact to non-NEM customers would be only $0.10 per customer per year. If the Company is at all concerned about the impact to residential bills, it should first focus on the areas that increase bills by many orders of magnitude more than any purported cost shift from NEM customers could ever do.[20]

Even with these caveats, the last two of Brattle's analyses (the timing of NCP demand and hourly profile during the system peak day) can be dismissed in separate steps. Residential NEM customers and residential non-NEM customers share distribution infrastructure. Therefore, the fact that the NEM customers do not peak at the same time as the rest of the residential class or the system provides beneficial load diversity to the Company's distribution and generation assets. Expert witness Custodio evaluates data provided by the Company to demonstrate that the load characteristics of NEM customers do

[19] ELPC-CE-868, "Residential Load and Energy Summary.xlsx"
[20] Calculations from "ex0220-Miller-1-3 and WP-1-25" scaling the 2018 residential and NEM actual sales to the test year sales.

not demonstrate meaningful differences from other residential customers that would support different class treatment. Further, because the NEM customers are not peaking at the same time as the rest of the residential class, it necessarily follows that the NEM customers peak load occurs during an hour when the infrastructure of the residential class has spare capacity (otherwise, the peaks would occur in the same hour). Removing NEM customers that provide load diversity therefore makes the system *more expensive* for the rest of the residential class, not less expensive.

The hourly load profile on the peak day also shows the benefits that NEM customers provide to the residential class. Figure 1 below is reproduced from Brattle's workpapers.[21] As demonstrated using Brattle's data, NEM customers have a much lower inflow peak during the hour of system peak compared to the rest of the residential class peaking during the peak hour. Additionally, the net flow of the NEM customers during the hour of the system peak is actually *negative.* Not only did NEM customers not add load during the single highest load hour of the year, they actually reduced it.



[21] ELPC-CE-868, "Residential Load and Energy Summary.xlsx"

Figure 1 - Brattle Load on Summer Day

Q. THESE ARGUMENTS APPEAR TO SUPPORT THE NOTION THAT NEM CUSTOMERS WOULD BE BETTER OFF IF THEY WERE TREATED AS A SEPARATE CLASS AS THEY APPEAR LESS COSTLY TO SERVE. DO YOU ADVOCATE FOR THIS?

A. No, I do not. While I show later in my testimony that NEM customers are in fact less costly to serve, I do not believe that they should be treated as a separate class in the CCOSS. There is benefit in having customers add load diversity to the residential class. As JCEO witness Claudine Custodio discusses in her testimony, there are many groupings of residential customers that may have different costs to serve. In addition to the analysis Ms. Custodio presents, separating subgroups of customers in a CCOSS types out would be administratively burdensome and confusing for customers. Overall, I believe it is beneficial to the entire customer class that NEM customers are not separated out into a separate class.

Moreover, one must recognize that the CCOSS model is an abstraction of the Company's physical system. NEM customers live in the same neighborhoods as non-NEM customers and share the same distribution assets. The notion of there being a separate distribution system for NEM customers than for non-NEM customers is clearly incorrect. JCEO witness Karl Rábago provides an overview of the policy justification for keeping NEM customers (or any customer group that increases load diversity) in the residential class. Given Mr. Rábago's analysis, the bar to model residential customers separately in the CCOSS model should be high. The variation in the load characteristics of NEM customers is not significant enough to clear this bar.

Q. TURNING TO BRATTLE'S OTHER ANALYSIS ON THE STATISTICAL SIMILARITY OF THE NEM AND NON-NEM CUSTOMERS, WHAT DO YOU FIND?

A. While mathematically correct, Brattle's analysis does not produce meaningful results, and implementing Brattle's conclusions would result in perverse outcomes. If the fact that two of the three metrics for NEM customers produced statistically significant differences from non-NEM customers is sufficient justification for treatment as different CCOSS class, then it logically follows that any subset of customers that produce similar results also warrants treatment as a different rate CCOSS class. However, Brattle did not perform any tests of any other subset of residential customers to determine if the same analysis produced similar results. For instance, Brattle could have tested rural customers vs. urban customers, or detached houses vs. apartments, or those with electric heat and those without. These analyses would likely have similarly found that the load patterns of these customers are distinct from each other, but neither Brattle nor the Company proposes or treats these residential customers sub-classes as separate CCOSS classes. Should the Company choose to endorse Brattle's findings, and treat NEM customers as a separate class, the Company may find itself in a position to make distinctions between groups of customers that are neither warranted nor equitable.

Q. ARE YOU AWARE OF ANYONE HAVING PERFORMED SIMILAR ANALYSES OF CUSTOMER GROUPINGS IN THIS CASE?

A. Yes. JCEO witness Custodio performed a statistical cluster analysis of roughly 10,000 customers and found there were multiple distinct groupings of customers that had very different load characteristics. When generalized to the full residential class, these customer clusters contain far more individuals than do NEM customers.

Q. DID YOU PERFORM THE SAME ANALYSIS THAT BRATTLE DID ON DIFFERENT SUBSETS OF CUSTOMERS?

A. Yes. While I did not have data to perform the specific comparisons above, I did have data to perform a much simpler analysis: comparing the load of customers that use a certain amount of energy per year to the residential class absent these customers. As the results show, if two of three metrics is sufficient to break out NEM customers in the CCOSS model, then the Company must also break out many other customers groups. To be clear, I do not advocate that the Company *should* in fact break out those customer groups, but make this point only to illustrate that the Company does not appear to consistently apply the Brattle study's justification for breaking out NEM customers in the CCOSS model to any other residential customer groups.

Q. PLEASE DESCRIBE THE ANALYSIS YOU PERFORMED.

A. I began by taking extracts of non-NEM customers that had similar annual energy usage to the inflow of NEM customers (roughly 11,500 kWh per year) and the net inflow of NEM customers (roughly 10,000 kWh). I also pulled data for customers that used around 11,000 kWh per year.[22] Figures 2, 3, and 4 below contain the monthly values for the sales, CP, and NCP metrics, respectively. These charts are analogous to those on page 8-9 of the Brattle Residential NEM Report.[23]

Using the same process that Brattle used to extract the load of NEM customers from the rest of the residential class, I determined the monthly CP, NCP, and energy sales for each of these "classes" along with the data for NEM inflow, "NEM Net" (where hourly inflow and outflow are netted prior to being aggregated), and "NEM Net > 0" (where hourly inflow and outflow are netted prior to being aggregated, but where any net negative hours were set to 0). Once the key metrics were compiled, I performed the same two-tailed paired sample t-test that Brattle used on each combination. My findings are illustrated in the following charts:

[22] These extracts were performed by JCEO witness Will Kenworthy from the hourly load data provided by the company. The "11.5k" customers included those with annual usage of 11,000 – 12,000 kWh, the "11k" customers from 10,500 – 11,500 kWh, and the "10k" customers from 9,500 – 10.500 kWh per year. The total hourly load was compiled and plugged into a separate version of the Company's "Attachment 56&57" worksheet to produce the load metrics.

[23] The NEM customer values were calculated using the Company's updated data provided in ELPC-CE-111.

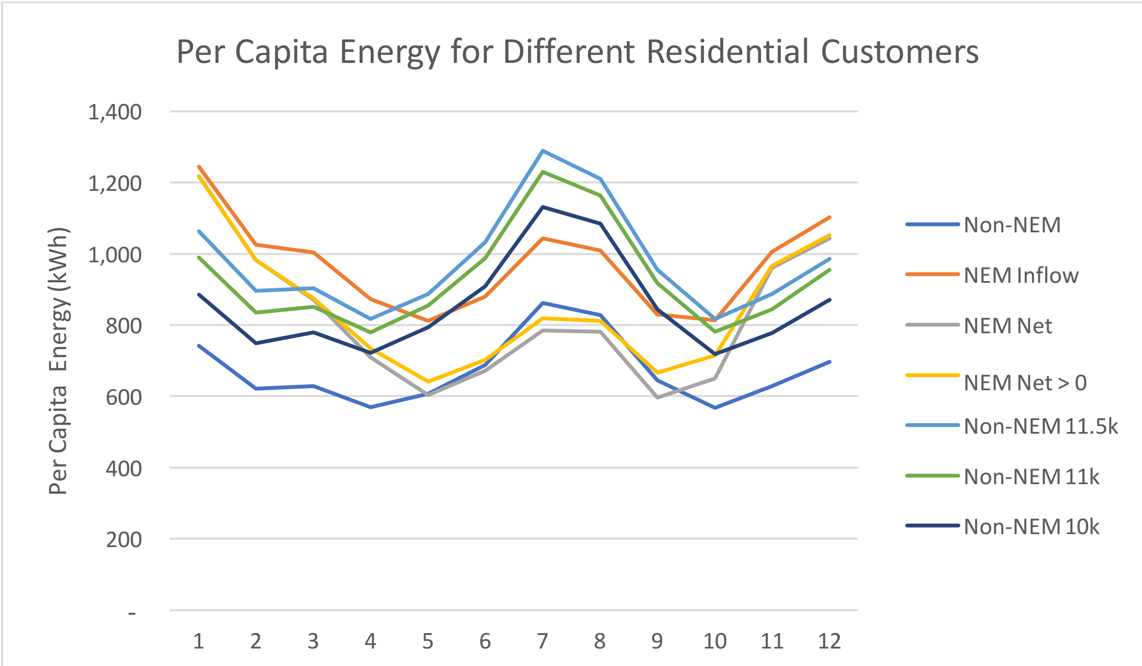


Figure 2 - Per Capita Sales for Different Residential Classes

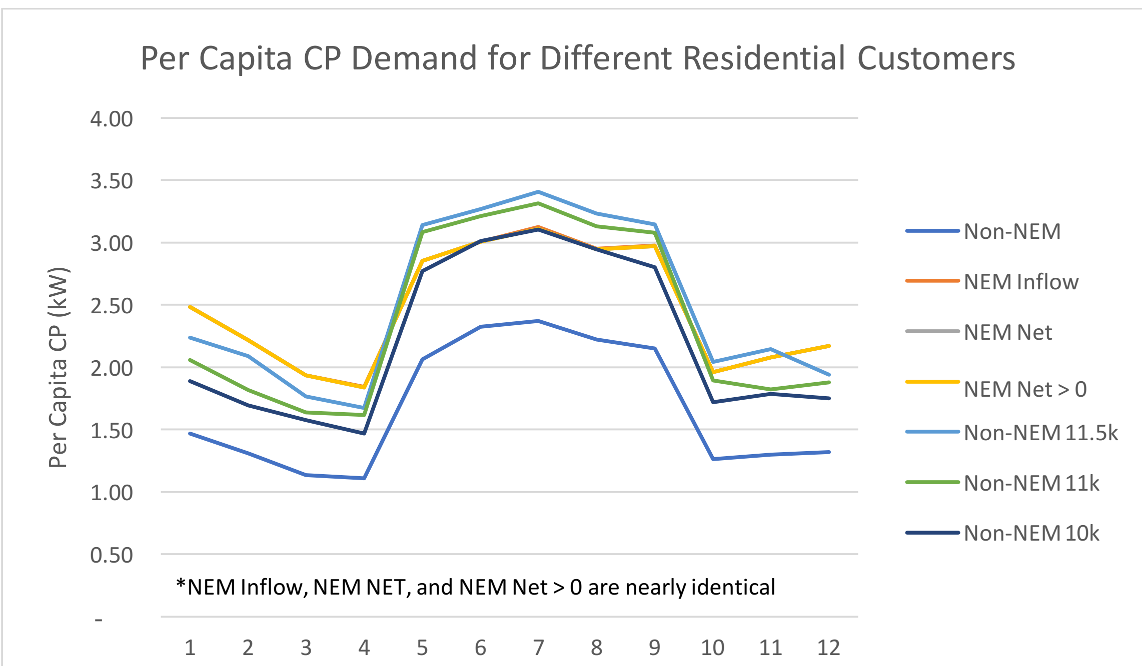


Figure 3 - Per Capita CP Demand for Different Residential Classes

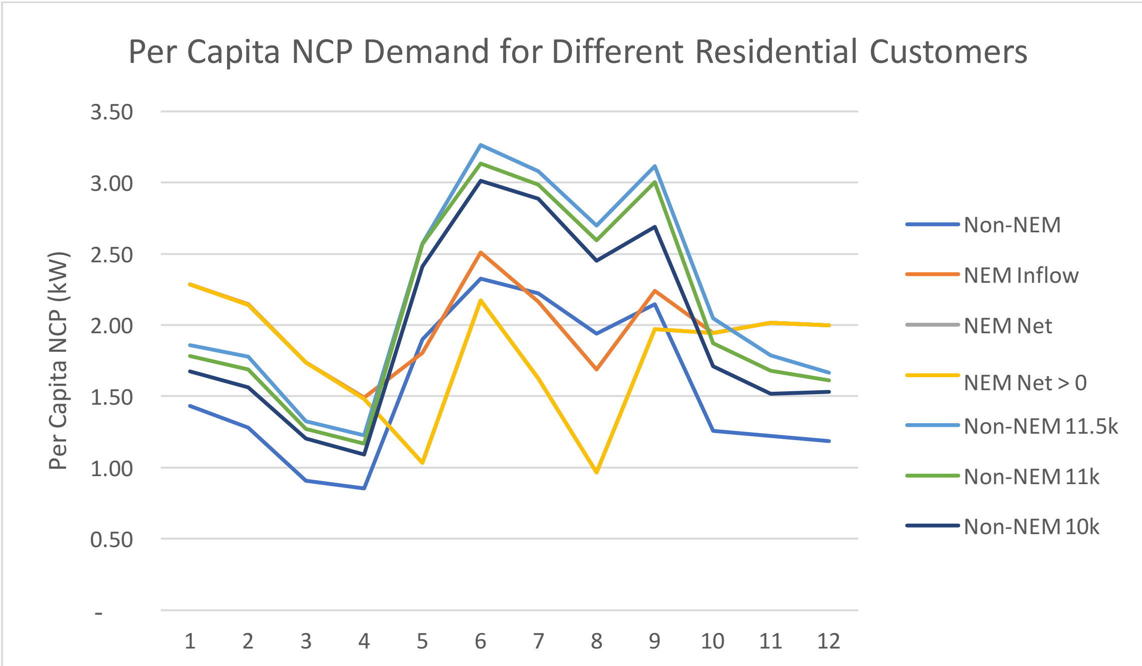


Figure 4 - Per Capita Sales for Different Residential Classes

Q. WHAT WERE THE RESULTS OF YOUR ANALYSIS?

A. It turns out to be very easy to find several subsets of customers that have statistically significant differences from the residential class for the load metrics that Brattle used. Table 2 below shows the p-values of the t-tests for each combination. Values in green underline represent pairings where there is a statistically significant ($p < 0.05$) difference between the average monthly per capita values of sales, CP, and NCP.

Energy	**Avg. Annual Energy**	**Rest of Res**	**NEM Inflow**	**NEM Net**	**NEM Net > 0**	**Non-NEM 11.5k**	**Non-NEM 11k**
Residential	8,084						
vs. NEM Inflow	11,639	0.00000					
vs. NEM Net	9,871	0.02263	0.00008				
vs. NEM Net > 0	10,182	0.00570	0.00007	0.00288			
vs. Non-NEM 11.5k	11,744	0.00000	0.83913	0.03643	0.05623		
vs. Non-NEM 11k	11,190	0.00000	0.40341	0.12653	0.20145	0.00000	
vs. Non-NEM 10k	10,260	0.00000	0.02291	0.63768	0.91825	0.00000	0.00000
CP		**Rest of Res**	**NEM Inflow**	**NEM Net**	**NEM Net > 0**	**Non-NEM 11.5k**	**Non-NEM 11k**
vs. NEM Inflow		0.00000					
vs. NEM Net		0.00000	0.07076				
vs. NEM Net > 0		0.00000	0.07076	-			
vs. Non-NEM 11.5k		0.00000	0.52801	0.50685	0.50685		
vs. Non-NEM 11k		0.00000	0.25598	0.27255	0.27255	0.00040	
vs. Non-NEM 10k		0.00000	0.00118	0.00136	0.00136	0.00000	0.00001
NCP		**Rest of Res**	**NEM Inflow**	**NEM Net**	**NEM Net > 0**	**Non-NEM 11.5k**	**Non-NEM 11k**
vs. NEM Inflow		0.00445					
vs. NEM Net		0.30675	0.02781				
vs. NEM Net > 0		0.30675	0.02781	0.00000			
vs. Non-NEM 11.5k		0.00000	0.28072	0.12838	0.12838		
vs. Non-NEM 11k		0.00000	0.53494	0.21916	0.21916	0.00002	
vs. Non-NEM 10k		0.00000	0.88775	0.44330	0.44330	0.00000	0.00002

Table 2 - p-values for T-Tests

Q. WHY DID YOU CONDUCT THIS ANALYSIS?

A. I performed this common statistical analysis to demonstrate that the comparisons Brattle attempts to make are out of line. When we have sufficient data, it is possible to run statistical models that look at whether groups we think of as "different" are really meaningfully "different" in a statistical sense. Brattle relies on these types of analyses in conducting its analysis, and I also rely on these analyses in demonstrating that Brattle missed the mark in several ways.

Q. WHICH OF THESE RESULTS DO YOU FIND PARTICULARLY USEFUL?

A. There are two types of instructive results in these figures. The first is when two seemingly similar customers groupings produce statistically significant differences in the metrics. The second is when seemingly different customer groupings do not produce statistically significant differences in the metrics.

To the first type of result, the data show that non-NEM residential customers using roughly an average of 11,500 kWh, 11,000 kWh, and 10,000 kWh produced meaningfully distinct results from the rest of the residential class in each of energy usage, CP demand, and NCP demand. An even more powerful results is that the groups of customers using roughly 11,500 kWh, 11,000 kWh, and 10,000 kWh all produced meaningfully different results from each other, despite the very small difference in average usage and similar CP and NCP charts (see Figures 2-4, above).

Regarding the second type of result, there is no statistically significant difference between "NEM inflow" customers and "Non-NEM 11.5k" customers in any of the metrics, between "NEM Net" and "Non-NEM 10k" customers in two of the three metrics, and between "NEM Net > 0" and "Non-NEM 10k" customers in two of the three metrics, despite these customers groups using very similar amounts of annual energy. Effectively, it is not appropriate to assume these customers have different load metrics.

Q. PUT TOGETHER, WHAT DO THE RESULTS OF YOUR ANALYSIS TELL YOU?

A. The results tell me that the Commission should disregard Brattle's analysis of the difference of NEM customers to non-NEM customers. NEM customers represent a *de minimus* share of the residential class in terms of customers, energy use, and demand. NEM and non-NEM customers are comingled in neighborhoods and share equipment. Brattle's statistical analysis methodology—that results in a stronger distinction between non-NEM customers using an average of 11,744 kWh per year and non-NEM customers using an average of 11,190 kWh per year than between NEM customer and non-NEM customers—simply does not demonstrate that NEM customers and non-NEM customers are meaningfully different for the purposes of a CCOSS. My conclusion is supported by the findings of witness Custodio, who demonstrates that the variation between NEM and non-NEM customers is not sufficiently significant to justify treatment as a separate rate class.

B. The Data that the Company Provided to Brattle was Severely Limited and is Inconsistent with More Recent Data

Q. WHAT WERE SOME OF THE DATA ISSUES IN THE DATA THE COMPANY PROVIDED TO BRATTLE?

A. There were two major problems with the data that the Company provided Brattle. The first involved customers that had hourly data but were missing data from certain hours or days. The second related to customers that were designated as NEM customers but for whom the Company had no hourly data. Brattle acknowledged these data issues and addressed them through different methods.[24]

For the missing hours, Brattle designed a regression analysis based on variables such as weather, season, and day of week. For any hour in which more than 40% of data was missing, Brattle replaced the observed inflow data with the regression results.[25] For the missing customers, Brattle simply scaled the observed data based on monthly ratio of customers for which it had data. For instance, in a month where Brattle had data for only 50% of the customers, it took the resulting hourly load data and doubled it.[26]

Q. DID BRATTLE PROVIDE ANY JUSTIFICATION FOR THE 40% CUTOFF FOR REPLACING OBSERVED DATA WITH REGRESSION RESULTS?

A. No, it did not.

Q. HOW MANY NEM CUSTOMERS WERE MISSING DATA ENTIRELY?

A. Based on the data provided, Brattle determined there were 767 residential NEM customers at the beginning of 2018, a figure which grew to 1,654 by the end of 2018. However, the Company only had data for a fraction of these customers. At the end of January, data was only available for 384 customers, or 50% of the data set. In December 2018, data was available for 1,249 customers, or 75% of the data set. [27]

[24] Brattle Residential NEM Report at 5.
[25] Brattle Residential NEM Report at 21.
[26] Brattle Residential NEM Report at 24.
[27] ELPC-CE-868, "Residential Load and Energy Summary.xlsx"

This sizable discrepancy is potentially problematic. By scaling each month up by the ratio of NEM customers with and without data, Brattle is implicitly assuming that the customers with data are statistically representative of the customers without data. However, Brattle performed no analysis to determine if this was the case. Rather, it simply scaled up the data it had to represent the NEM customers that were missing data.

Q. DOES THIS CREATE CONCERNS WITH RESPECT TO THE VALIDITY OF BRATTLE'S CONCLUSIONS BASED ON THE DATA THEY USED?

A. It is a potential issue because the CCOSS model uses data from just a handful of hours to allocate many costs. One hour each month contributes to the "12CP" allocator, which is used to allocate transmission costs. Only four hours in the summer are used to determine the "4CP" allocator, which is used in part to allocate production capacity costs.[28] Most critically, one single hour in the entire year is used for the "class peak" allocator, which is used to allocate nearly all non-customer distribution costs. Small movements in the data for these specific hours can have an outsized impact on the CCOSS results. Because of the impact this data can have on ultimate results, I have concerns that the Brattle conclusions are not sufficiently robust to support a conclusion about ratemaking.

Q. DID THE COMPANY PROVIDE ANY REASON WHY IT WAS MISSING DATA FROM SO MANY CUSTOMERS?

A. None that I could identify. In its response to a data request asking for updated NEM customer information, the Company stated:

> The Company used an updated process to gather the information requested than what was used for providing information to Brattle. Although the Company does not believe the results will differ much, it is possible that the individual account level data provided for 2018 in response to this discovery may not perfectly aggregate to what Brattle used for the DG analysis.[29]

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[28] The current cost allocation for production uses 75% weighting on 4CP demand and 25% weighting on total energy. The Company has proposed to increase the demand weighting to 89% and reduce the energy weighting to 11%. This would further exacerbate the impact of small changes between the data.

[29] Attachment CEO-9 (KL-5), ELPC-CE-111 (Revised).

Q. **HOW DIFFERENT WAS THE UPDATED DATA FROM THE DATA THAT WAS PROVIDED TO BRATTLE?**

A. It was substantially different. Table 3 below shows the difference in the customer counts between the original data and the updated data.[30]

	Brattle Total	Brattle with Data	Updated
January 2018	767	384	1,541
December 2018	1,654	1,249	1,620

Table 3 - NEM Customers Original and Updated

Q. **ASIDE FROM THE OBVIOUS DIFFERENCE IN THE CUSTOMER COUNTS IN THE TWO DATA SETS, DID THE UNDERLYING LOAD METRICS ALSO LOOK DIFFERENT?**

A. Yes. Using the Company's workpapers, I recreated the key CCOSS metrics (energy usage by period, class demand, 12CP demand, and 4CP demand) for the updated set on both a per capital and absolute basis. As I discuss later in my testimony, I excluded some of the customers in the updated data set that were missing data from more than a threshold number of hours. The values for "ELPC 111" below in Figure 5 represent the data set that I used in my analysis.

[30] ELPC-CE-868, "Residential Load and Energy Summary.xlsx"

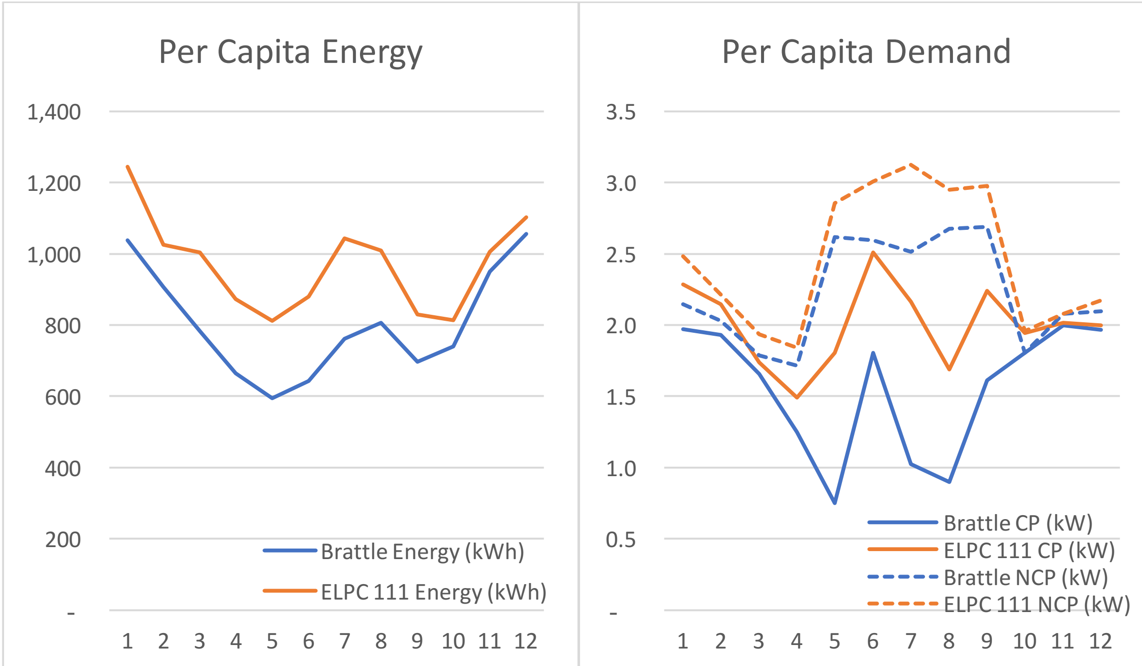

Figure 5 - NEM Customers Original and Updated Per Capita Energy and Demand

The missing information from the original Brattle data set, even after processing, produced values that were consistently lower on a per capita basis than the updated data set. However, data is not entered into the CCOSS on a per capita basis, but rather on an absolute basis. The large customer growth in the Brattle data skews these cost determinants in a complex way inside the CCOSS. Figure 6 below shows the absolute data used in the CCOSS. The growth in customers is particularly apparent in the energy and CP data.

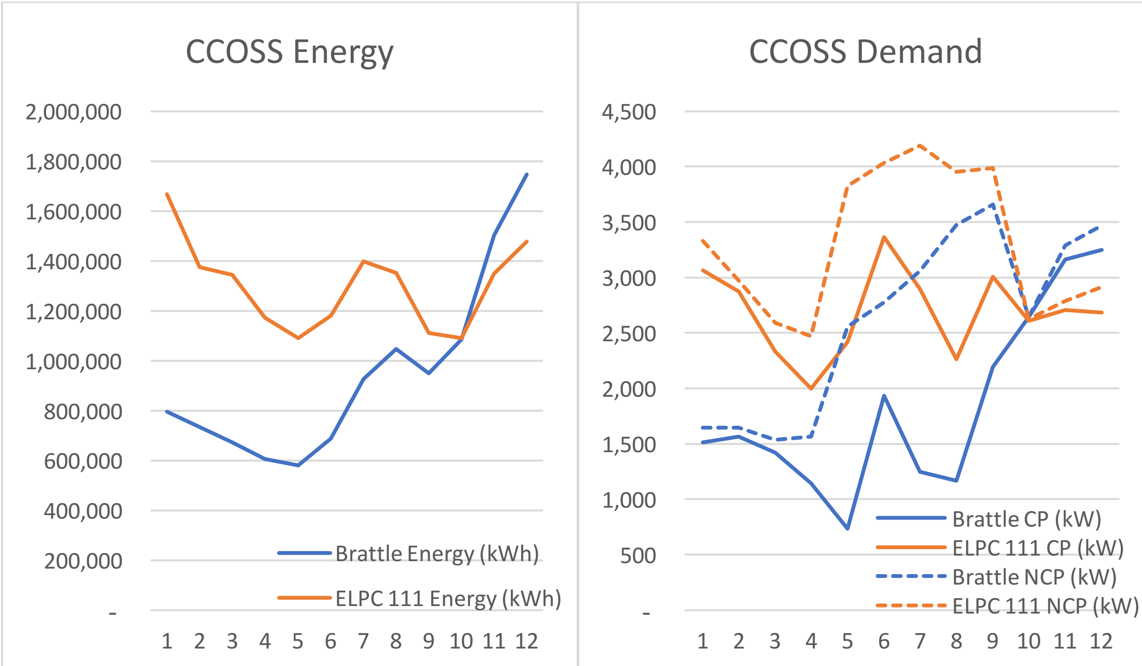

Figure 6 - NEM Customers Original and Updated Absolute Energy and Demand

Q. IF BRATTLE WAS UNDERCOUNTING THE ENERGY AND DEMAND OF NEM CUSTOMERS, DOES THAT ALLOCATE FEWER COSTS TO THE NEM CUSTOMERS IN THE CCOSS, ALL ELSE BEING EQUAL?

A. It does. Generally, costs are allocated based on a customer class's share of a particular allocator. For instance, production capacity costs are primarily allocated based on the 4CP allocator.[31] The CCOSS model calculates the share of the total 4CP from each class and distributes production capacity costs based on these shares. If the NEM customers have relatively lower 4CP values, they would be allocated fewer 4CP-based production capacity costs.

However, the other allocators such as energy (including subsets such as summer on-peak, summer off-peak, critical peak, etc.), 12CP demand, and customer counts also play a role in establishing the final costs that are allocated to the class. Further, the final rate design calculates the cost to be recovered per kWh. Even if fewer costs were allocated, if there are fewer kWh over which to recover the costs, the final rate may be the same or even higher.

[31] This is a simplification as the Company's CCOSS allocates production costs on a mix of 4CP and total energy.

C. Brattle Incorrectly Modified the Company's CCOSS Model and Inappropriately Presented its CCOSS Results

Q. AFTER BRATTLE ADJUSTED THE ORIGINAL DATA, WHAT DID IT DO NEXT?

A. Brattle modified a version of the Company's CCOSS that only considered 2018 data, instead of using a three-year average, and plugged in the load characteristics of the NEM customers and the remaining non-NEM customers. In doing so, it indicated that it "calculated costs allocated to Residential class and Residential NEM customers using the adjusted model such that load data for all classes are consistent."[32]

Q. WHAT ADJUSTMENTS DID BRATTLE MAKE TO THE MODEL?

A. Brattle bypassed some of the logic in the CCOSS model and directly plugged in the residential 2018 NEM and non-NEM load data. In doing so, it skipped a critical step in the model's inner workings: normalizing actual 2018 data for all classes based on the test year data.

In the Company's original model, a three-year average of 2016, 2017, and 2018 load characteristics such as sales and 12CP were used to rescale class allocators based on the 2018 test year sales data. For example, the ratio of January CP to total sales was calculated for each year and then averaged. The resulting value was then multiplied by the 2018 test year sales to reconstitute the test year January CP value.[33]

Because Brattle did not have 2016 or 2017 NEM data, it could not perform the same three-year averaging, instead relying only on 2018 data. While this is not necessarily an issue in and of itself, by skipping the step that normalized actual 2018 data to test year data for *the residential class only*, Brattle inadvertently pushed the entire model out of balance. Brattle ended up treating the residential class differently: all other classes' allocators are calculated based on the test year sales, but the residential class is skewed based on actual 2018 results.

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[32] Brattle Residential NEM Report at 13.

[33] ex0220-Aponte-1-3 and WP-1-81 - 4CP 75-0-25.xlsx

Q. WHY DOES IT MATTER THAT ONLY THE RESIDENTIAL CLASS IS BASED ON ACTUAL 2018 RESULTS?

A. The total residential sales that Brattle plugged into the model was 13,101,243 MWh. By contrast, the residential test year data in the version of the model that Brattle used was 12,226,200 MWh. Because all of the key load characteristics are scaled to the test year data, this mistake meant that the relative size of all residential class load data was roughly 7.2% higher than appropriate compared to other classes.

Q. IF THIS HAPPENED TO BOTH THE NEM AND NON-NEM CUSTOMERS, WHY DOES THIS MATTER?

A. It matters because the CCOSS works based on the relative size of a customer class's value compared to the total value of that allocator. For instance, in the original CCOSS model, the residential class represented 41.2% of energy usage, but 50.1% of 4CP demand. This means that 41.2% of the energy-related costs will be allocated to the residential class as a whole, but 50.1% of the 4CP-releated costs will be allocated to residential customers. Because the residential class's share of the total 4CP-related costs is already larger, scaling up the value by 7.2% allocates more incremental 4CP-related costs to the residential class than incremental energy-related costs to the residential class. Further, because the relative size of allocators between the NEM customers and non-NEM customers changes for the various allocators, this scaling can impact the customer groupings differently. Due to the complexity of the CCOSS model, it is very difficult to tell how this error percolates through the rest of the analysis.

Q. DESPITE THIS ERROR, WHAT DID THE BRATTLE CCOSS ANALYSIS SHOW?

A. While Brattle did not showcase this in its main results, Brattle's own report shows that NEM customers are slightly less expensive to serve than non-NEM customers. In the appendix to its report, Brattle shows that the total cost to serve NEM customers is approximately 7%

lower than other residential customers, equal to $0.153 / kWh for NEM customers compared to $0.164 / kWh for non-NEM customers.[34]

Q. DOES THIS CONTRADICT MR. MILLER'S DIRECT TESTIMONY SUGGESTING THAT NEM CUSTOMERS ARE MORE COSTLY TO SERVE THAN NON-NEM CUSTOMERS?

A. It does. Mr. Miller asserted that the cost to serve "residential customers with DG ranges between 20% to 50% more than that of other customers."[35] Unfortunately, Mr. Miller relies on a misleading presentation of the Brattle findings. Mr. Miller relied on a breakdown of costs that are neither reflective of rates nor the CCOSS model. Figure 7 below shows the results in the body of the Brattle presentation, which appear to be the basis for Mr. Miller's assertion. Further below, Figure 8 shows the results from the Brattle study's appendix, showing the lower total cost to serve NEM customers as compared to non-NEM customers. Comparison of Figure 7 and Figure 8 makes clear that Mr. Miller's assertion is off base.

Annual Cost Comparison for Non-NEM Residential Class and Residential NEM Customers

	Total Allocated Cost ($)		Unitized Allocated Costs		
Cost Type	**Non-NEM Residential**	**Residential NEM**	***Measure***	**Non-NEM Residential**	**Residential NEM**
Production					
Net Capacity Cost	$539,242,902	$252,051	*$/kW CP*	$150	$202
Capacity-Related Cost Offset	$279,809,565	$201,661	*$/kW CP*	$78	$162
Non-Capacity-Related Cost	$561,603,008	$472,444	*$/kWh Sales*	$0.043	$0.042
Total	**$1,380,655,475**	**$926,156**			
Distribution					
Demand-Related Cost	$633,234,152	$661,939	*$/kW NCP*	$165	$181
Customer-Related Cost	$140,735,282	$144,813	*$/Customer*	$88	$88
Total	**$773,969,434**	**$806,752**			

Figure 7 - Brattle Results - Main Report

[34] Brattle Residential NEM Report at 29.
[35] Miller Direct at 26-27.

Annual Cost Comparison for Non-NEM Residential and Residential NEM Customers

	Total Allocated Cost ($)		Allocated Cost per kWh Sales	
Cost Type	**Non-NEM Residential**	**Residential NEM**	**Non-NEM Residential**	**Residential NEM**
Production				
Net Capacity Cost	$539,242,902	$252,051	$0.041	$0.022
Capacity-Related Cost Offset	$279,809,565	$201,661	$0.021	$0.018
Non-Capacity-Related Cost	$561,603,008	$472,444	$0.043	$0.042
Total	**$1,380,655,475**	**$926,156**	**$0.105**	**$0.082**
Distribution				
Demand-Related Cost	$633,234,152	$661,939	$0.048	$0.058
Customer-Related Cost	$140,735,282	$144,813	$0.011	$0.013
Total	**$773,969,434**	**$806,752**	**$0.059**	**$0.071**

Figure 8 - Brattle Results – Appendix

Q. WHY ARE THE RESULTS FROM THE MAIN BODY OF THE REPORT (REPRESENTED IN FIGURE 7) MISLEADING?

A. Brattle's main report shows production net capacity cost and capacity-related cost offset in terms of $/kW CP and distribution demand-related costs in terms of $/kW NCP. This is misleading for three reasons.

First, the CCOSS does not allocate any costs based on the single CP hour.[36] This hour is combined with others to produce the 4CP value, which is then combined in part with total energy usage to produce the 4CP allocator. Similarly, the "capacity-related cost offset" is not an actual cost that is allocated in the CCOSS model. Rather, it is a plug-in value found after subtracting the production capacity costs and non-capacity-related costs from the total revenue requirement, which, by definition, includes any revenue deficiency the Company is modeling. In Brattle's modified CCOSS, the total production revenue requirement of $926,156 includes a revenue deficiency of $264,727, meaning nearly 30% of the production costs for NEM customers (and in fact more than the entire "capacity-related cost offset" value) is not based on the CCOSS allocators but based on the Company's target revenue. By contrast, the non-NEM customers in this model show a 13% revenue deficiency, meaning substantially fewer costs are allocated to these customers outside the CCOSS allocators. In

[36] Attachment CEO-10 (KL-6), ELPC-CE-1258

other words, the results that Brattle presented do not contain detailed enough data from the CCOSS to reflect the actual cost to serve NEM customers based on the their load characteristics. The best Brattle can do is use a circular stand in for how NEM customer costs should be allocated. But even that modeling fiction shows that NEM customers are lower cost to serve than non-NEM customers.

Secondly, presenting information in the way Brattle does suggests that lowering a class's CP would somehow increase costs to serve that class. This defies common sense. When I manually lowered the 1CP value (corresponding to class load during the July 2018 peak hour) for the NEM customers from 1,247 kW to 1,000 kW, the recalculated net capacity costs fell from $252,051 to $242,543. That outcome made sense:; lower demand during the peak hour of the year reduces the 4CP allocator, which reduces production costs allocated to that class. However, since net capacity costs are not determined solely from this value, the $/kW CP value that Brattle shows actually increased from $202 to $243. The total cost to serve NEM customers fell, but Brattle's presentation of the results (which were the exact ones relied on by Mr. Miller) suggests the costs increased. That outcome does not make sense.

Finally, residential customers are not charged based on 1CP or NCP demand. Residential customers are charged a fixed customer charge and a volumetric per kWh of inflow rate. As long as this is the case, it is appropriate to frame the cost to serve the customers in terms of the rates they are charged. While one could present CCOSS results in terms of $ / customer, this does not fully account for the fact that NEM customers tend to use more energy than the average non-NEM customer.[37] Denoting the costs per kWh of sales is preferable as it helps normalize the results between higher-use customers and lower-use customers.

[37] Although as we see below, their usage patterns produce lower per-customer costs than similarly sized non-NEM customers.

Q. WHAT IS YOUR OVERALL CONCLUSION REGARDING HOW THE COMMISSION SHOULD TREAT RESIDENTIAL NEM VERSUS NON-NEM CUSTOMERS IN THE CCOSS?

A. The Brattle Report should be disregarded in its entirety. Brattle tried to make use of poor data, but its source data was clearly inconsistent with updated values for the same customers. Brattle incorrectly modified the Company's CCOSS model, skewing the allocation of costs between the various classes. It presented information in a misleading manner. Despite all of these shortcomings, in its appendix, Brattle itself in fact determined that NEM customers had a lower cost per kWh to serve than non-NEM customers—a result that the Company appears to ignore in its testimony.

Q. DID THE COMPANY PRESENT ANY OTHER INFORMATION RELATED TO THE COST TO SERVE RESIDENTIAL NEM CUSTOMERS?

A. No. Mr. Miller relied exclusively on the Brattle report for the basis of his testimony that residential DG customers were more expensive to serve.[38] And as I explained above, Mr. Miller makes no reference to the determination that NEM customers have a lower cost per kWh to serve than non-NEM customers, contained in the appendix to the Brattle study. Based on this, I also recommend that the Commission assign no weight to Mr. Miller's assertion that residential DG customers are more expensive to serve.

[38] Attachment CEO-11 (KL-7), ELPC-CE-114.

III. THE COMPANY'S TREATMENT OF OUTFLOW ENERGY IS INCONSISTENT WITH ITS COST OF SERVICE MODEL

Q. PLEASE PROVIDE AN OVERVIEW OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I discuss the Company's proposal to use instantaneous metering to collect inflow and outflow for CCOSS and billing purposes. I also discuss some differences between the physical reality of the electric grid and the abstractions that are contained in the CCOSS model, and why one can carry constructs such as inflow and outflow too far.

Q. WHAT ARE YOUR PRIMARY CONCLUSIONS?

A. The Company's narrow view of inflow and outflow (from the perspective of an individual NEM customers) fails to account for how the power grid works in reality. As a result, the Company's use of instantaneous metering for inflow and outflow and failure to incorporate hourly netting in its load study are inconsistent with its CCOSS and do not produce a cost-based method for calculating the cost to serve residential customers. This forgoes $41.50 per year in value that each NEM customers provides to the residential class as a whole.

A. The CCOSS Model is an Abstraction, not a Physical Reality

Q. DOES THE CCOSS AND ITS RESULTS PERFECTLY REFLECT THE REALITY OF THE COMPANY'S PHYSICAL SYSTEM?

A. Not it does not, nor does anyone claim that it does. The CCOSS is complex model that attempts to reflect how various groups of customers use the system and produce equitable results for all classes. However, as evidenced by some of the other topics in this proceeding (such as whether to continue using the 4CP 75/0/25 allocator or switching to a different method), the CCOSS can produce dramatically different results depending on the settings used.

One clear example where the model diverges from reality is in the use of average line losses rather than marginal line losses. Marginal line losses are higher during times of peak demand. By contrast, the average line losses that the Company uses understate losses during high-load hours and overstate them during low-load hours. Because customer groups use the system differently during peak and off-peak hours, this decision necessarily favors one type of class (e.g. one that uses more load during high-use hours) over another (e.g. one that uses less load during high-use hours).

Another example is in how customers use the grid compared to how they are billed for their usage. Customers on demand rates such as GSD and PD are billed for demand based on the highest average demand during a 15-minute interval in a month. Momentary fluctuations such as those caused by starting appliances or machinery are smoothed out from a billing perspective, even though they are supplied by the grid. Further, 15-minute billing intervals are combined to produce hourly load profiles for use in the CCOSS. The Company also uses demand "ratchets" in many of its commercial rates that place a floor under the billing demand of a customers that is independent of their usage during a given month. However, the CCOSS does not use the billing demand.[39] To the extent that billing demand is elevated compared to the CCOSS demand due to the use of ratchets, the retail demand rates may over-collect demand revenue.

Q. WHAT ARE SOME OTHER WAYS THAT COSTS ARE INCURRED THAT MIGHT NOT MATCH HOW THEY ARE MODELED IN THE CCOSS?

A. The bulk of the distribution operation and maintenance ("O&M") costs come from maintaining the overhead lines. These costs are split among the classes based on an allocator (appropriately named "Overhead Distribution") that is itself based on class the share of total class peak. In effect, the Company assumes that distribution O&M expenses scale based on the independent peak of each class, and that the costs can be accurately allocated to classes based on their share of the sum of all class peaks. In reality, it is likely that expenses like tree trimming disproportionately fall on the residential and small commercial class, as those

[39] Attachment CEO-12 (KL-8), ELPC-CE-1264

customers are more likely to live in tree-lined areas than are large commercial and primary customers. However, by allocating these costs based only on the share of the total of class peaks, the CCOSS breaks from the actual way in which costs are incurred.

Q. DOES THIS MEAN THAT THE BRATTLE CCOSS IS NOT USEFUL?

A. No. The CCOSS is useful. But it attempts to do the impossible: track and allocate billions of dollars of expenses caused from maintaining a system with thousands of assets that serves millions of customers. This is, of course, part and parcel of a CCOSS. The fact that the CCOSS simplifies reality is a necessary step to obtain something approximating a model of the Company's system. However, there may be ways in which the Company can update its CCOSS to more accurately reflect how its customers use its system. Even the best CCOSS models deviate from a true physical representation of the system, but COSS models should still strive to be as accurate as possible. Of course, there are always deviations in how customers use the grid and how they are modeled.

Q. WHAT IS ONE WAY IN WHICH THERE IS A DEVIATION BETWEEN HOW NEM CUSTOMERS USE THE GRID IN REALITY AND HOW THEY ARE MODELED IN THE CCOSS?

A. NEM customers occasionally send power back to the grid, reversing the power flow through their meter. Given the extremely low density of residential NEM customers in Michigan (roughly 1 out of 1,000 customers), the overwhelming likelihood is the outflow will travel to the nearest line transformer where it will then flow to the NEM customer's neighbor to help meet their inflow needs. The Company does not generate or transmit this energy; at best, a tiny fraction of its local distribution assets are used to move the outflow from one neighbor to another. Despite this, the CCOSS treats the inflow to the NEM customer's neighbor as if it had been generated, transmitted, and distributed by the Company. This assumption is not an accurate representation of how the excess energy generated by NEM customers is used on the Company's system.

B. Using Instantaneous Inflow and Outflow Does Not Comport with the Cost of Service Model

Q. WHAT LOAD METRICS – I.E. CHARACTERISTICS OF LOAD - ARE USED IN THE CCOSS MODEL?

A. Several load metrics are used in the CCOSS to derive the cost allocators. Table 4 below shows the unique characteristics used for the residential class. The CCOSS also incorporates average line losses to calculate allocators at different voltage levels (e.g. premise, secondary distribution, sub-transmission, etc.) and accounts for customer groups that do and do not use certain assets (e.g. the Primary class does not use the secondary distribution system). The primary cost allocator for production capacity costs is derived from a mixture of the 4CP and total energy allocators.

Load Characteristic	Definition
12CP Data	Sum of monthly class load during monthly peak system hours
4CP Data	Sum of monthly class load during June – Sept peak system hours
Classpeak	Highest single hour for the class independent of system peak
Energy	Annual energy usage
Energy On-Peak	Energy usage non-holiday weekdays between 6 AM and 10 PM
Energy Off-Peak	Energy usage other than on-peak
Energy On-Peak Summer	On-peak usage from June – September
Energy Off-Peak Summer	Off-peak usage from June – September
Energy On-Peak Non-Summer	On-peak usage from October – May
Energy Off-Peak Non-Summer	Off-peak usage from October – May
Critical Peak Energy	Energy usage non-holiday weekdays from 2 PM to 6 PM

Table 4 - CCOSS Load Characteristics

Q. HOW ARE THESE LOAD METRICS USED TO ALLOCATE COSTS AND CALCULATE THE REVENUE REQUIREMENT?

A. The Company uses the class load data to calculate many different cost allocators. For instance, while distribution costs are almost all allocated based on the "classpeak" metric, some are allocated based on a class's share of the total class peak at secondary system level while others are based on the class's share of the total class peak at the sub-transmission level. Additionally, some cost allocators are based on other cost allocators. For instance, the Labor allocator is based on a mix of transmission, production, distribution, and customer allocators. Overlooking these nuances, Table 5 below maps the primary allocator used for both the production and distribution revenue requirement for the Company's total system using the currently approved "75/0/25" 4CP allocator.[40]

($000)	Allocated Cost Examples	Production	Distribution	Total	Share
Energy	Fuel, var. O&M, market sales	$680,073	-$20,984	$659,089	15.6%
4CP	Production capacity	$1,578,043	$62,826	$1,640,869	38.9%
12CP	Transmission expenses	$484,475	$10,904	$495,379	11.8%
Class	Distribution capacity, O&M	$72,570	$1,065,971	$1,138,541	27.0%
Customer	Meters, billing, back office	$16,632	$251,101	$267,733	6.4%
Misc.		$0	$12,454	$12,454	0.3%
Total		**$2,831,793**	**$1,382,271**	**$4,214,064**	**100.0%**

Table 5 - CCOSS Revenue Requirement by Primary Allocator

Q. WHAT ARE YOUR OBSERVATIONS ABOUT THE COMPANY'S SYSTEM-WIDE COSTS AND REVENUE REQUIREMENT?

A. On a system-wide level, almost exactly two-thirds (66.3%) of the total revenue requirement goes towards paying for assets and expenses associated with generating and transmitting energy, with roughly one-quarter more for paying for the distribution system to deliver this energy to customers' residences and businesses.

Q. ARE THESE RATIOS SIMILAR FOR THE RESIDENTIAL CLASS?

A. They are similar, as I will discuss later in my testimony. The residential class is allocated relatively more costs based on 4CP (production), classpeak (distribution), and customer related allocators, and relatively less costs based on energy-related allocators than the system as a whole.

Q. WHAT IS THE COMMON UNIT OF TIME IN THE CCOSS?

A. It is one hour. Regardless of how often customers load data is metered, it is aggregated at the hour level before calculating the metrics above.

[40] Totals do not perfectly tie to the top-line revenue requirement due to the handling of non-jurisdictional costs and miscellaneous charges. However, the totals here capture 98.6% of the revenue requirement. Further, the small costs for energy, 4CP, and 12CP in the distribution function and for class and customers in the production function are the result of mapping allocators that were in turn based on other allocators to these functions.

Q. PLEASE DISCUSS HOW LOAD STUDY DATA IS CONVERTED INTO A STRUCTURE TO BE USED BY THE CCOSS.

A. The Company begins with load study data to derive an hourly load profile by class for the test year. This data is normalized for weather and customer growth.[41] Once it has been adjusted, the Company uses a worksheet to produce the metrics listed in Table 4 above. These values are input into the CCOSS for each class for the past three years. A three-year average is calculated for each metric, which is then normalized to the test year sales for the class. These values are then used to calculate the myriad cost allocators which are used in the remainder of the model.[42]

Q. HOW DOES THE COMPANY PREPARE DATA FROM NEM CUSTOMERS FOR USE IN THE CCOSS?

A. The Company uses dual channel metering to integrate instantaneous readings for inflow and outflow energy. The inflow energy in metered separately from the outflow energy. As such, it is possible to have a single hour in which there is both inflow and outflow energy.

Q. HOW DOES THE COMPANY ACCOUNT FOR OUTFLOW FROM NEM CUSTOMERS IN THE CCOSS?

A. The Company does not include outflow energy in any of the underlying load metrics in the CCOSS and does not produce any independent evaluation of the value of outflow. Instead of incorporating the outflow energy as an offset to inflow energy in the COSS for NEM customers or the residential class, it instead uses an outflow bill credit that is equal to the power supply less transmission portion of the NEM customer's retail rate.[43] In doing so, it is implicitly assuming the value from NEM outflow is equal to the cost of residential inflow of these components. As I discuss below, that is not supported by data.

Q. IS THE COMPANY'S APPROACH TO OUTFLOW ENERGY CONSISTENT WITH HOW OTHER FORMS OF LOAD REDUCTION ARE TREATED IN THE CCOSS?

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[41] Attachment CEO-13 (KL-9), ELPC-CE-1255
[42] Attachment CEO-14 (KL-10), ELPC-CE-1252
[43] Attachment CEO-15 (KL-11), ELPC-CE-870.

A. No. Individual residential customer data is not input into the CCOSS; rather, aggregate load characteristics for the entire residential class are used. Despite this, the Company draws an arbitrary line at the customer's meter, separating the flow of energy from the grid to the customer into inflow and the flow of energy from the customer to the grid as outflow. Taking a small step up in scale, such as looking at the line transformer, feeder, or substation, shows why this distinction is arbitrary from the perspective of the CCOSS.

Energy usage in the CCOSS is based on the entire class of customers and is intended to capture the total flow of energy from the company to the set of customers. As discussed above, when a NEM customers is exporting energy to the grid, the energy will simply flow to the nearest load, where it will be consumed. The Company did not need to use fuel to generate electricity to serve this load; it was produced by the PV system.

Similarly, the demand on the production and transmission system during the 4 or 12 hours a year when the CCOSS metric is calculated is impacted by the failure to deduct outflow. A class's demand on the system is the sum of all the demand from all its customers. If a customer activates a demand response asset during the peak hour, the peak load on the system is reduced accordingly. If the NEM customers' PV systems are generating during the peak hour, the load on the Company's power plants will be corresponding lower (including line losses). The final system peak value is necessarily net of all of these factors – including net of outflow – but the Company's methodology ignores this fact when allocating costs based on load that does not include outflow energy from the NEM customers.

Q. SHOULD OUTFLOW FROM PV SYSTEMS BE GIVEN CAPACITY CREDIT IN THE OUTFLOW CREDIT OR THE COSS, EVEN THOUGH IT IS NOT DISPATCHABLE?

A. Yes. The question of how much capacity credit that PV provides is one for reliability planning. As the Company is well aware based on its plans to meet a substantial portion of its peak demand through solar, PV can and will be appropriately incorporated into system-wide capacity planning to ensure that sufficient capacity is available to serve load.

But the CCOSS is a backward-looking analysis that only considers the actual load during certain key hours of the year. Whatever the state of PV generation was at that time (whether it was producing 100% or 40% of its generating capacity) should be included in the CCOSS, just as whatever the load of a customer was at time on the system at that time should be included. Excluding outflow energy in the CCOSS necessarily shortchanges the reductions in load that PV produces during critical hours.

Q. DOES ALL PV GENERATION RESULT IN OUTFLOW ENERGY?

A. No. Only when PV generation exceeds onsite usage will energy be exported to the grid. The combination of inflow and outflow represents the combination of PV generation, self-consumption, and customer load. The generation that is "self-consumed" also reduces usage and demand during critical hours and is the basis for the lower cost of service result that I explore in the next section. By simply using the inflow and excluding the outflow, the Company is incorrectly misrepresenting the state of the DG customer in its load metrics, and thus its CCOSS.

Q. WHAT IS THE IMPLICATION OF EXCLUDING OUTFLOW ENERGY IN THE CCOSS?

A. When the NEM customers are properly treated as part of the whole residential class, the failure to include outflow energy results in load characteristics such as energy use, 4CP, and classpeak that are too high. This in turn means that the residential class as a whole is allocated more costs than it should be, increasing the revenue that needs to be collected through rates.

Q. WHAT IS THE IMPLICATION FOR STUDIES SUCH AS BRATTLE'S THAT SEEK TO QUANTIFY THE COST OF SERVING NEM CUSTOMER SEPARATELY FROM THE REST OF THE RESIDENTIAL CLASS?

A. With my previous caveat that I do not believe NEM customers should be treated as a separate customers class in the CCOSS, studies (such as the Brattle study) that seek to quantify the cost of serving NEM customers separately from the rest of the residential class exacerbate this impact. Instead of the outflow energy being allocated to the entire group of residential customers, it would have instead been allocated to a subset of NEM customers. This would have a larger impact on the resulting load characteristics and the corresponding cost allocators. I perform this analysis in the next section of my testimony.

Q. WHAT IS THE MAGNITUDE OF OUTFLOW ENERGY DURING KEY HOURS?

A. Outflow energy from NEM customers is produced during many of the critical hours that are counted towards the CCOSS load metrics. On average, the outflow from NEM customers during the 4CP hours was 22% of the inflow during those hours. Outflow during the summer on-peak energy was 37% of the inflow during these hours. Outflow during the hour of the residential class peak was equal to 19% of the NEM customer class peak. On a percentage basis of the NEM customers inflow, these are sizable changes to the load metrics.

Q. WHAT IS THE IMPACT ON THE RESIDENTIAL CLASS FROM EXCLUDING THIS OUTFLOW?

A. I used a modified version of the Company's CCOSS that included only 2018 data (as 2016 data for NEM customers was not available). In the version that only included inflow energy, the proposed rate design for the residential class was $ 2,343,213,306. I then produced alternative load metrics that netted the outflow energy from the subset of customers used in my NEM customer analysis.[44] This reduced the residential class's demand and energy values, which in turn produced a lower proposed rate design target of $2,343,157,657.

This value is lower by $55,649 and represents $41.50 of value that each of the 1,341 NEM customer's outflow is providing to the residential class that is not captured in the CCOSS. This is equal to $0.0235 per kwh of outflow in savings to the residential class. Importantly, this is not stipulating that the value of outflow energy is worth only $0.0235 / kWh, but rather that this is the result of the mathematical redistribution that occurs in the CCOSS when one nets outflow energy from the residential class. Although the total reduction is small compared to the proposed rate design revenue for the entire residential class, there is no justification for excluding it from the CCOSS.

[44] My analysis included 1,341 NEM customers, or about 80% of those for whom the Company had data.

IV. NET METERED CUSTOMERS ARE LESS COSTLY TO SERVE THAN NON-NET METERED CUSTOMERS

Q. PLEASE PROVIDE AN OVERVIEW OF THIS SECTION OF YOUR TESTIMONY.

A. In this section, I discuss my analysis of the cost to serve residential NEM customers based on updated data and proper modification of the Company's CCOSS. I begin by detailing the updated NEM customers data and the steps I took to prepare it for the CCOSS. I continue with the modifications to the CCOSS model itself, and conclude by presenting the results in a manner that is consistent with the Company's rate design.

Q. WHAT ARE YOUR PRIMARY CONCLUSIONS?

A. Although I do not advocate for NEM customers to be their own class, if they were treated as such, they would be less expensive to serve than non-NEM customers. Further, NEM customers are less expensive to serve than non-NEM customers of a similar size. Billing NEM customers at the average non-NEM rate under the Company's proposed CCOSS method would overcharge the average NEM customer by $378 per year.

A. JCEO's Analysis Benefits from More Recent, Cleaner Source Data Than Brattle's Analysis

Q. YOU PREVIOUSLY ILLUSTRATED HOW MUCH CLEANER THE UPDATED NEM CUSTOMER DATA WAS COMPARED TO THE SET THAT WAS PROVIDED TO BRATTLE. WHAT STEPS DID YOU PERFORM TO PREPARE THIS DATA FOR USE IN THE CCOSS?

A. Despite being more complete than the data that the Company provided to Brattle, there were still some steps that needed to be taken to prep the updated NEM data for use in the CCOSS. While Brattle used regressions to fill in missing hourly load information, and grossed up load data to account missing customer data, I used a simpler method to adjust for missing data and customer growth: limiting the analysis to NEM customers who met a minimum number of hours for which there was data. After selecting these customers, I made adjustments to three stretches of time during which it was clear that the underlying data was invalid.

Q. WHY DID YOU SELECT CUSTOMERS IN THIS WAY?

A. I was attempting to minimize the need for data processing in my analysis. One could account for customer growth within a test year by normalizing the data to the average number of customers. This would ensure that data from January's CP hour would not be skewed compared to data from December's CP hour. However, the growth in the NEM class was considerably higher than the overall number of residential customers in the residential class. Further, given how few NEM customers exist, adjusting the data to account for this customer growth could inadvertently skew the data.

Q. HOW DID THIS FIRST STEP AFFECT THE DATA SET?

A. There were 1,541 unique NEM customers that appeared in the January data set from the Company. This figure rose to 1,620 unique NEM customers in December. The 79 additional NEM customers that came online represented just over a 5% increase to the NEM group through the year. Rather than attempt to normalize the data to adjust for this load growth, I excluded customers that were added during the test year.

Q. WHAT LEVEL OF HOUR LOAD AVAILABILITY DID YOU SET FOR THE CUTOFF?

A. I chose to retain customers that had data for at least 8,577 hours, or roughly 98% of all hours. This cutoff was based on my analysis of hours with data for the full customer data set. Figure 9 below shows the number of hours for each customer in the data set. Those at the far right side of the chart represent customers that came on part way through the year or had an inordinately high amount of missing data.

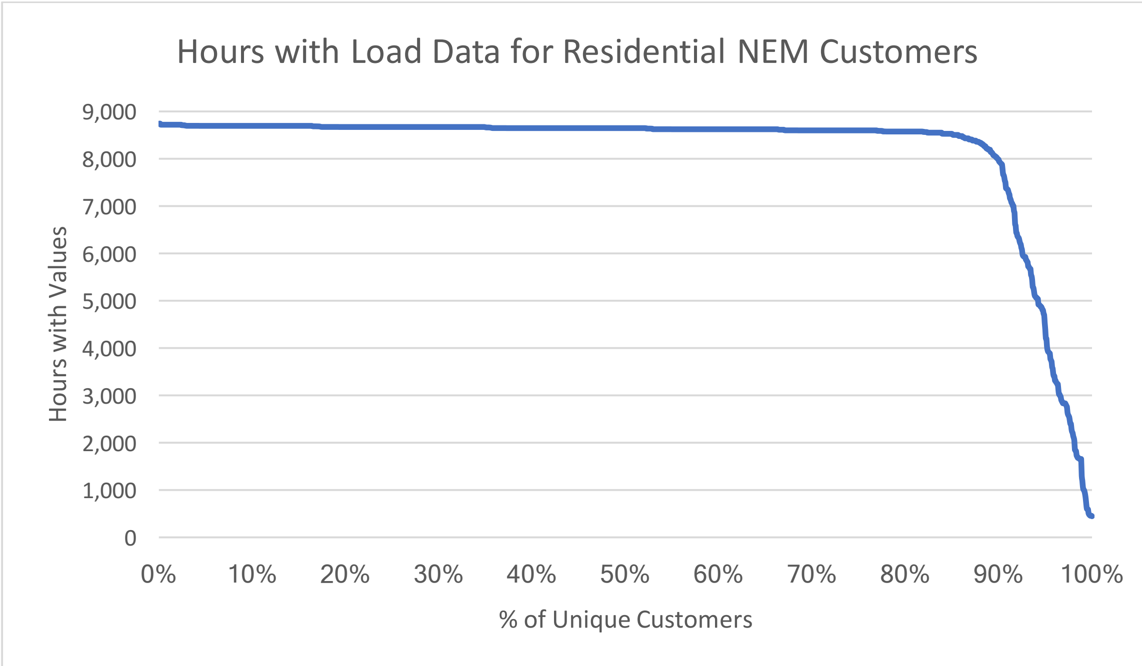

Figure 9 - Hours with Load Data for Residential NEM Customers

Figure 10 below shows the detail where the number of missing hours begins to change rapidly. Based on this information, I set the cutoff at 8,577 hours. This retained 1,341 customers, roughly 87% of those that were present in January 2018.

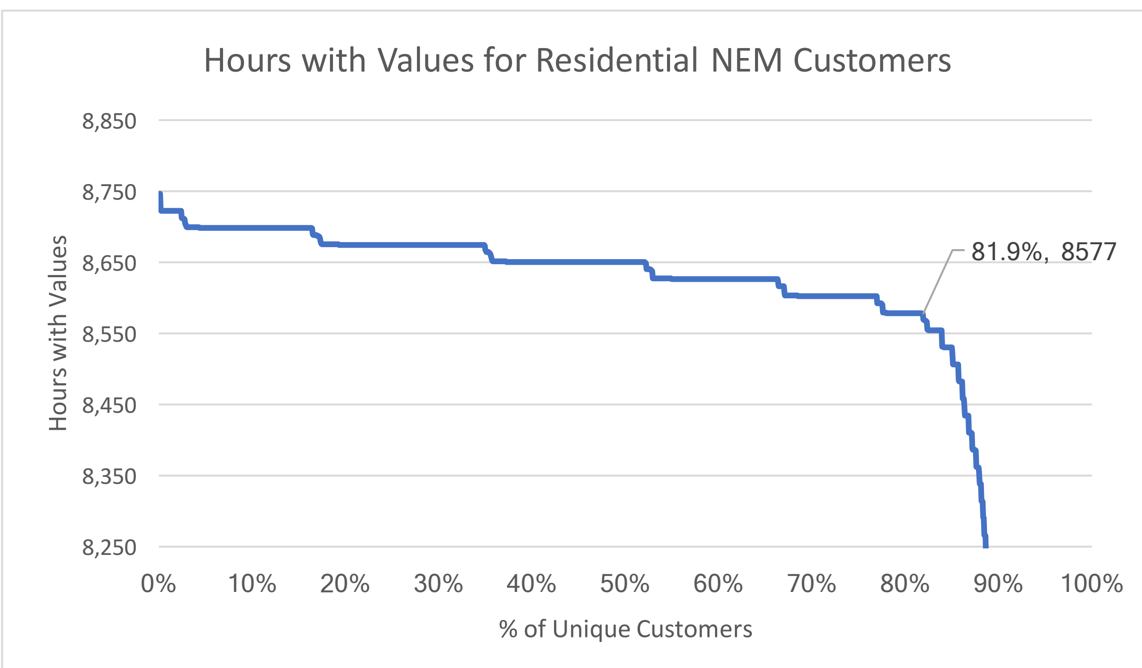

Figure 10 - Hours with Load Data for Residential NEM Customers - Detail

Q. DID YOU ANALYZE THE LOAD CHARACTERISTICS OF THE CUSTOMERS YOU EXCLUDED TO ENSURE THEY WERE SIMILAR TO THE CUSTOMERS THAT YOU INCLUDED?

A. Yes. I calculated the per capita load profile of the customers that were included and excluded and used this to calculate the main load characteristics used in the CCOSS. The per capita load characteristic values of the excluded customers were within 2-3% of the included customers, with some values higher and some values load. Based on this, I am confident that excluding these customers did not produce a material impact on my analysis.

Q. WHAT OTHER ADJUSTMENTS DID YOU MAKE TO THE LOAD DATA?

A. Once I had aggregated load data for this subset of NEM customers, I analyzed the hourly inflow and outflow data to see if there were any obvious discontinuities. In doing so, I found three periods (one in late January and two in mid-to-late August) in the year when the data clearly deviated from normal. Figure 11 shows these the original inflow and outflow data from three periods.

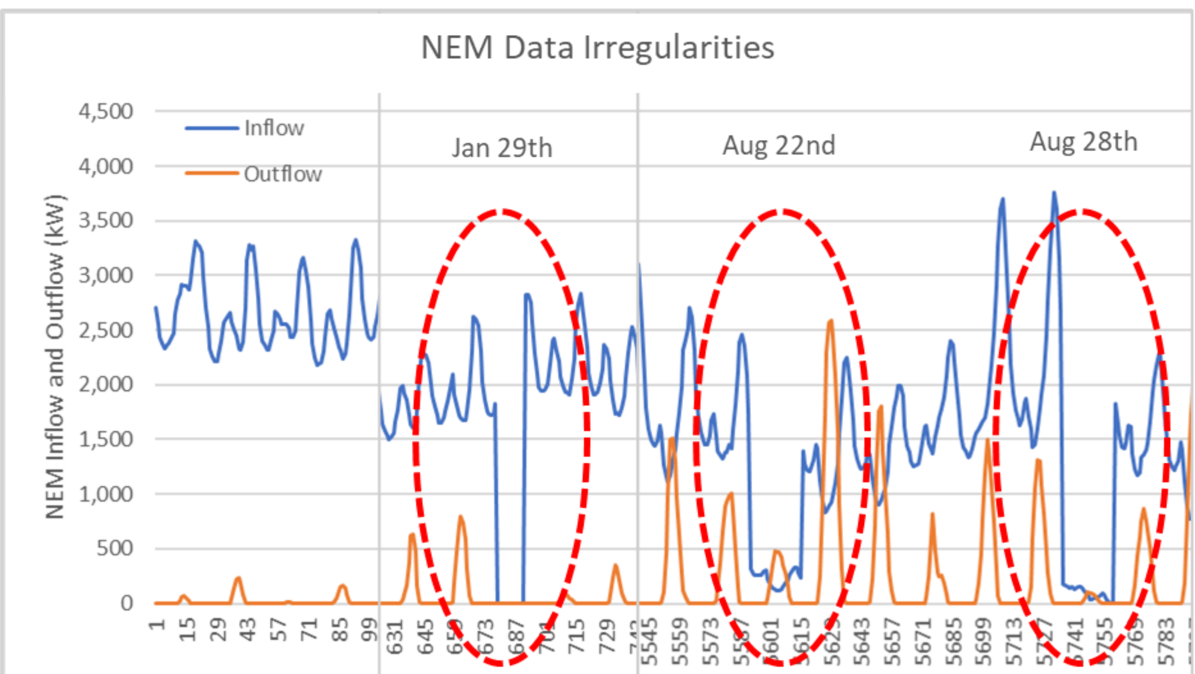

Figure 11 - NEM Data Irregularities

Q. **HOW DID YOU ADJUST THIS DATA?**

A. For the two August dates, I took the average of the hours on the days preceding and following the data irregularity. Because the January date was a Monday, I used an average of data from the following day and the previous Monday to as to avoid skewing the data with lower weekend usage.

Q. **DID ANY OF THESE DATA ISSUES FALL ON CRITICAL PEAK DAYS?**

A. No, they did not. As such, I view these adjustments as minor and primarily serve to adjust the energy usage of the NEM class.

Q. **AFTER YOU MADE THESE MODIFICATIONS, HOW DID YOU PROCEED?**

A. I used the baseline residential hourly data from the Company's load worksheets and developed several customers groupings listed below in Table 6. The CCOSS metrics for these groupings were produced by the worksheets in an identical manner.

Grouping	Avg. Usage (kWh)	Classpeak (kW)	Avg 4CP (kW)	Avg 12CP (kW)	Description
NEM Inflow	11,639	3.13	2.15	2.00	NEM customers inflow data only
11.5k	11,744	3.41	3.04	2.11	Non-NEM customers using between 11k and 12k kWh per year
NEM Net	9,871	3.11	1.68	1.78	NEM customers with hourly netting of inflow and outflow
NEM Net > 0	10,182	3.11	1.68	1.78	NEM customers with hourly netting of inflow and outflow. If net < 0, hourly data set to 0.
10k	10,260	3.10	2.76	1.98	Non-NEM customers using between 9.5k and 10.5k kWh per year
Residential	8,084	2.37	2.16	1.56	Average residential customers in 2018
NEM Outflow	1,768	2.31	0.47	0.22	NEM customers outflow data only

Table 6 - Customer Groupings

There are two logical groupings between these customers subsets. The first is between the NEM Inflow and 11.5k customers. Both groups used roughly the same amount of energy and had similar average 12CP demand. However, due to solar generation during peak hours, the NEM Inflow customers had meaningfully lower classpeak and average 4CP values. The second grouping is between the two NEM Net customer groups and the 10k customers. Again, the annual energy usage was similar, as was the classpeak demand.

However, the NEM Net customers had notably lower 4CP demand and somewhat lower 12CP demand.

Figure 12 below shows some of these values. It is evident from this chart how much lower average 4CP demand, a critical driver of overall costs, is for NEM customers compared to non-NEM customers of similar size. Likewise, average 12CP demand is lower for NEM customers than for similarly-sized non-NEM customers. Even classpeak, which drives distribution costs, is lower or equal to non-NEM customers of similar size.

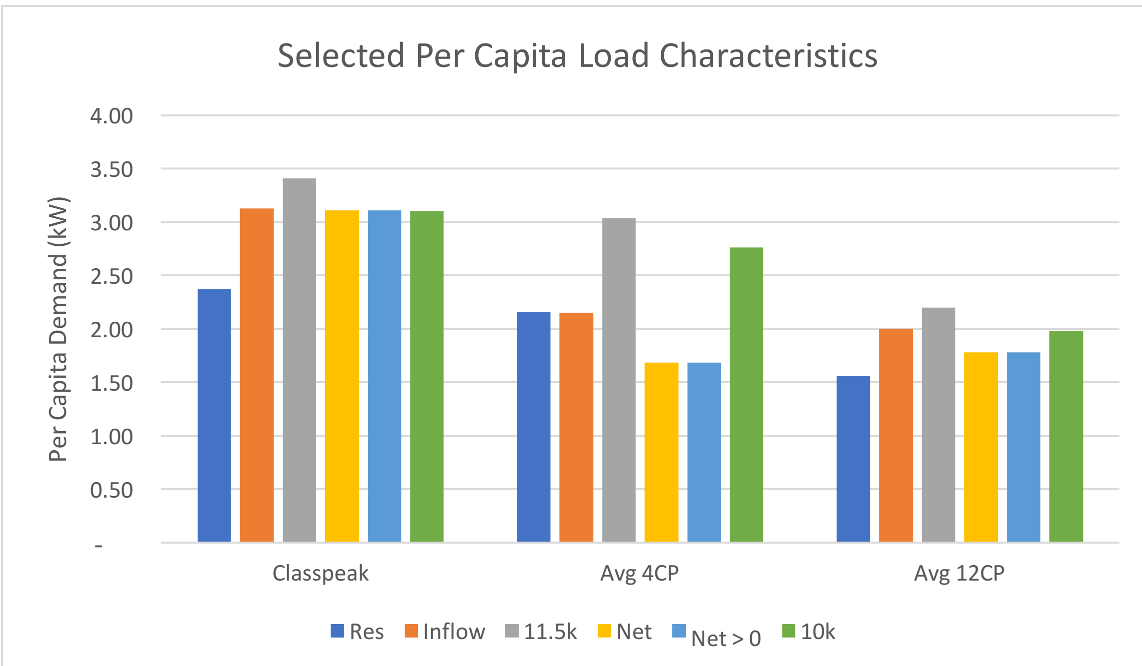

Figure 12 - Customer Grouping Selected Per Capita Load Characteristics

Q. HOW DO THESE CUSTOMER GROUPINGS COMPARE TO THE RESIDENTIAL CLASS AS A WHOLE?

A. Generally, the NEM Inflow customers have reasonably higher energy usage, class peak, and 12CP demand compared to the residential average, with similar average 4CP demand. The NEM Net customers have higher energy usage and class peak, somewhat higher average 12CP demand, and lower average 4CP demand.

Figures 13 and 14 below show the usage heat map for the NEM Net and non-NEM 10k customers with the same scale. The annual usage for these customer groups are within 4% of each other, but the timing of their usage is quite different. The NEM Net customers use much less energy during the various peak periods compared to the non-NEM 10k; the difference is largest during the CCOSS critical peak period and the retail rate on-peak period.

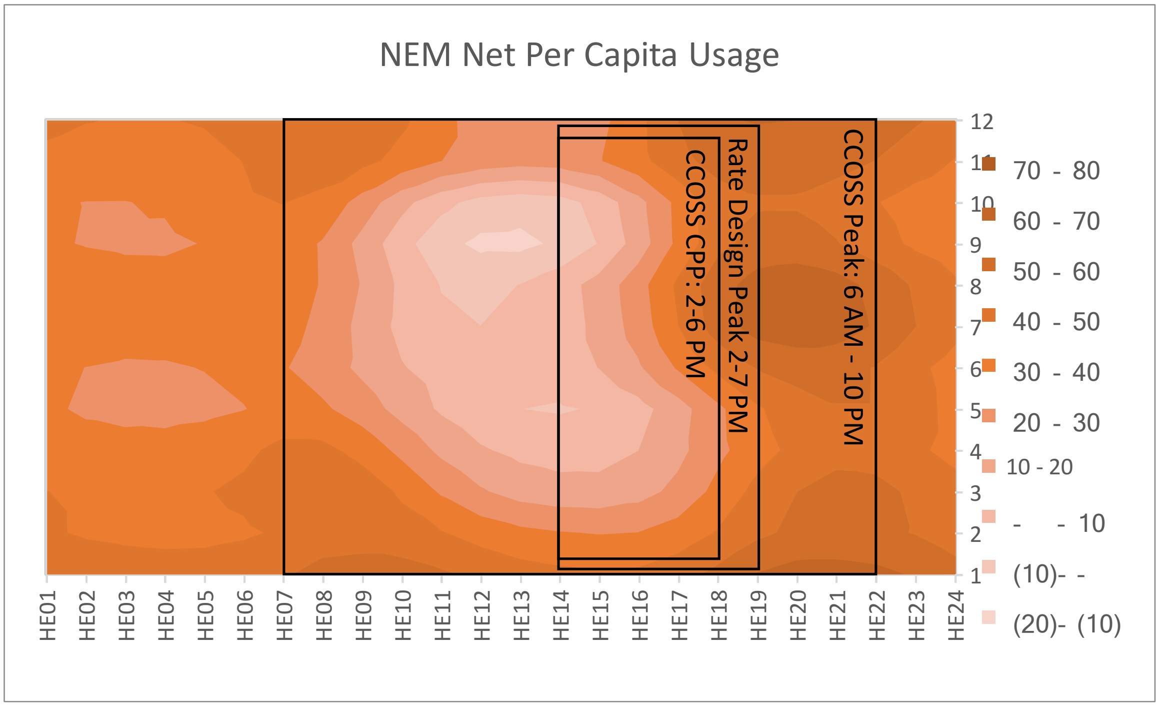

Figure 13 - NEM Net Per Capita Usage

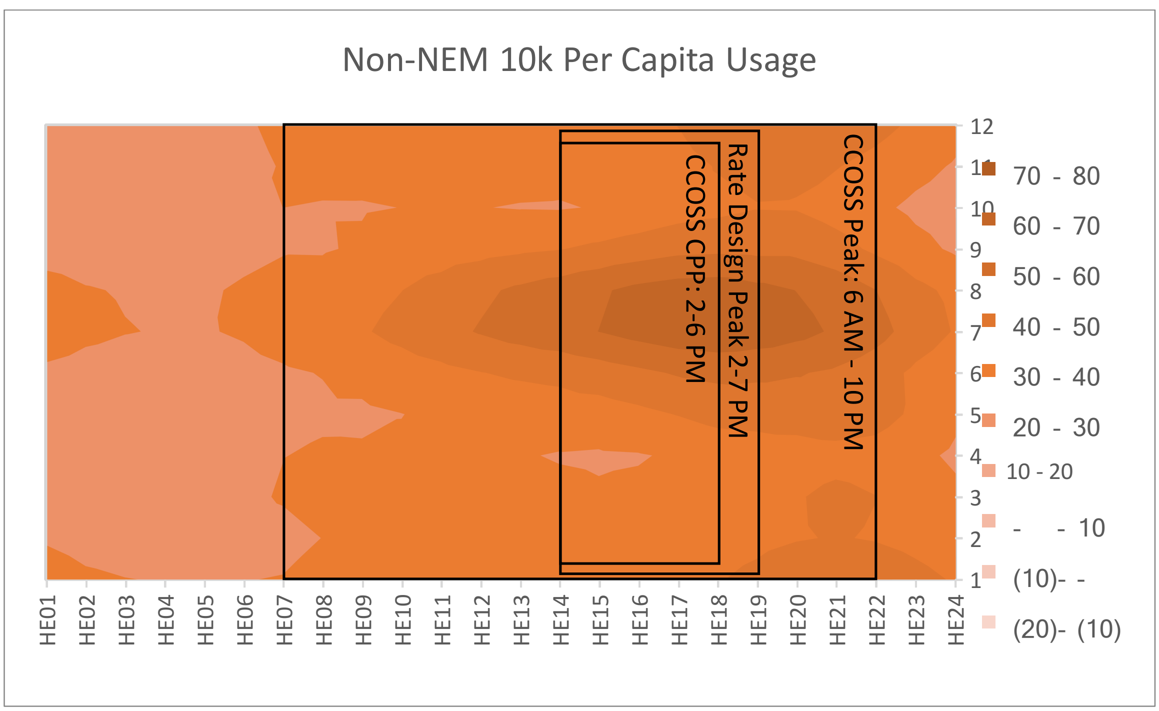

Figure 14 - Non-NEM 10k Per Capita Usage

Q. DOES THE FACT THAT NEM CUSTOMERS HAVE MORE ANNUAL INFLOW AND NET ENERGY THAN NON-NEM CUSTOMERS MATTER IN TERMS OF THE CCOSS?

A. No. As shown above, the cost to serve customers is not based solely on the total annual energy usage but is instead based on the mix of peak and off-peak energy usage and several different demand variables. Additionally, the CCOSS model internally accounts for the relative size of energy and demand allocators. It is entirely possible for a customer group with higher total annual usage to end up with a lower cost to serve compared to groups with lower annual usage.

B. Properly Adjusting the CCOSS Model Demonstrates the Lower Cost of Service for NEM Customers

Q. ONCE YOU DEFINED YOUR CUSTOMERS GROUPINGS, HOW DID YOU MODIFY THE COMPANY'S CCOSS TO INCORPORATE THESE NEW GROUPS?

A. I began with one of the Company's CCOSS worksheets from this docket that was already designed to separately cost the RT and the RS customer groups.[45] A few adjustments were needed to be made to remove hardcoded values and restore the disaggregation functionality for two residential classes.[46] I also retained only the 2018 load data for all classes, but unlike the Brattle analysis, retained the normalization of the residential sales to the test year sales to maintain consistency across all classes.

Q. DID USING ONLY 2018 DATA IMPACT THE RESULTS?

A. It did. Load data from 2018 appears to have been relatively higher for the residential class than the three-year average of 2016-2018. Using the three-year average, the residential class proposed rate design revenue results in a total revenue of $0.17786 / kWh. Using only 2018 data, this increases to $0.18824 / kWh. However, since I was only concerned with the

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[45] ex0220-Aponte-1-3 and WP-1-81 - 4CP 75-0-25. In this worksheet, the "RT" class was used for the customer subgroup being analyzed, while the "RS" class was used for the remainder of the residential customers.

[46] The Company had hardcoded the number of customers for the RT class to zero, and had overwritten formulas that calculated the value for "distribution revenue from elect sales" and "PSCR base revenue". Customer data was plugged in based on the load studies, and RT class revenue values were set proportional to the total sales of the RT and RS classes.

relative results of the customer subgroups and not establishing actual revenue requirements for each class, one can simply compare the results from the 2018 NEM, non-NEM customers, and full residential class to produce meaningful results between these customer groups.

Q. DID YOU USE THE PROPOSED RATE DESIGN REVENUE METRIC TO COMPARE THE COST TO SERVE THE VARIOUS GROUPS?

A. Yes. While I was able to trace the underlying costs through the CCOSS, several groups of customers were left with a sizable "revenue deficiency" indicating that that particular class was not earning the Company's proposed return. Rather than reallocate this additional cost, I left it categorized as "Rev Deficiency" in the figures below. Notably, the NEM Inflow customer group produces a revenue surplus, while the NEM Net and NEM Net > 0 group produces smaller deficiencies than non-NEM customers or the 11.5k and 10k customer groupings.

Q. WHAT DO YOU CONCLUDE FROM THE RESULTS OF YOUR ANALYSIS?

A. I find that NEM customers overall are substantially less costly to serve than are non-NEM customers overall, and that NEM customers are substantially less costly to serve than non-NEM customers of similar energy usage.[47] Figure 15 and 16 below contains the per kWh and per customer results of my analysis. The values in these charts show the "cost rate" that would collect the Company's proposed revenue from each customer grouping based on their total allocated costs and total energy usage from the grid. It is analogous to an "all-in" retail rate that would collect these costs were these customer groups assigned different retail rates.

[47] Because the customers groups were very small compared to the rest of the residential customers class, a single "Rest of Res" representing the non-NEM customers is used to represent the inverse customer group. The actual variation in the inverse "rest of res" customer group was *de minimus*.

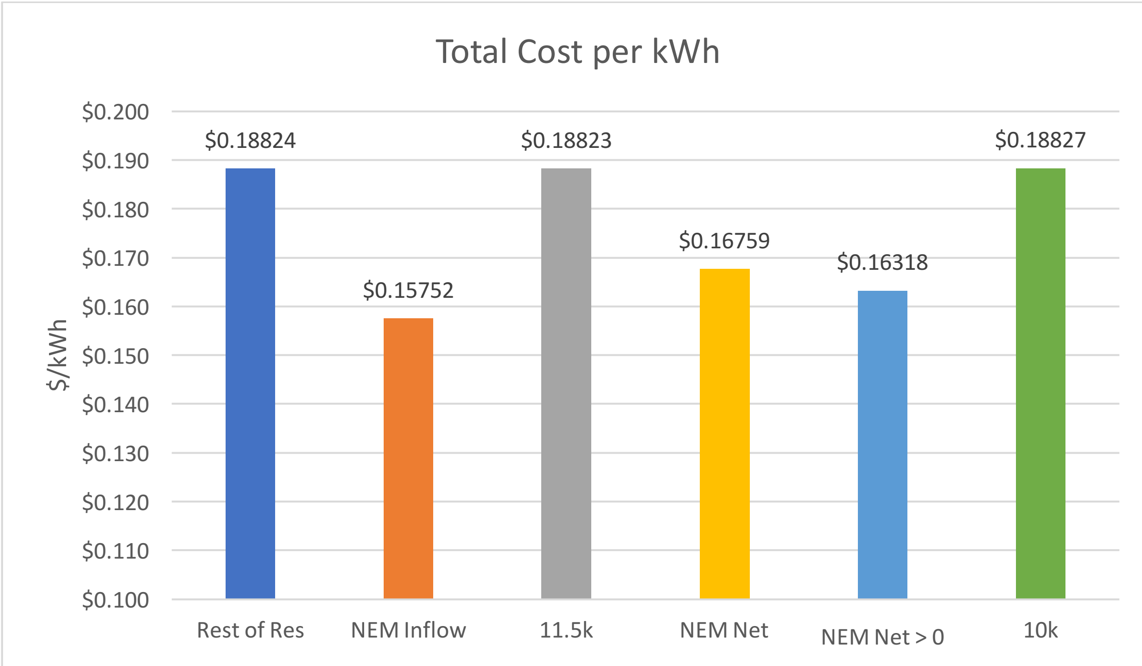

Figure 15 - CCOSS Total Cost per kWh

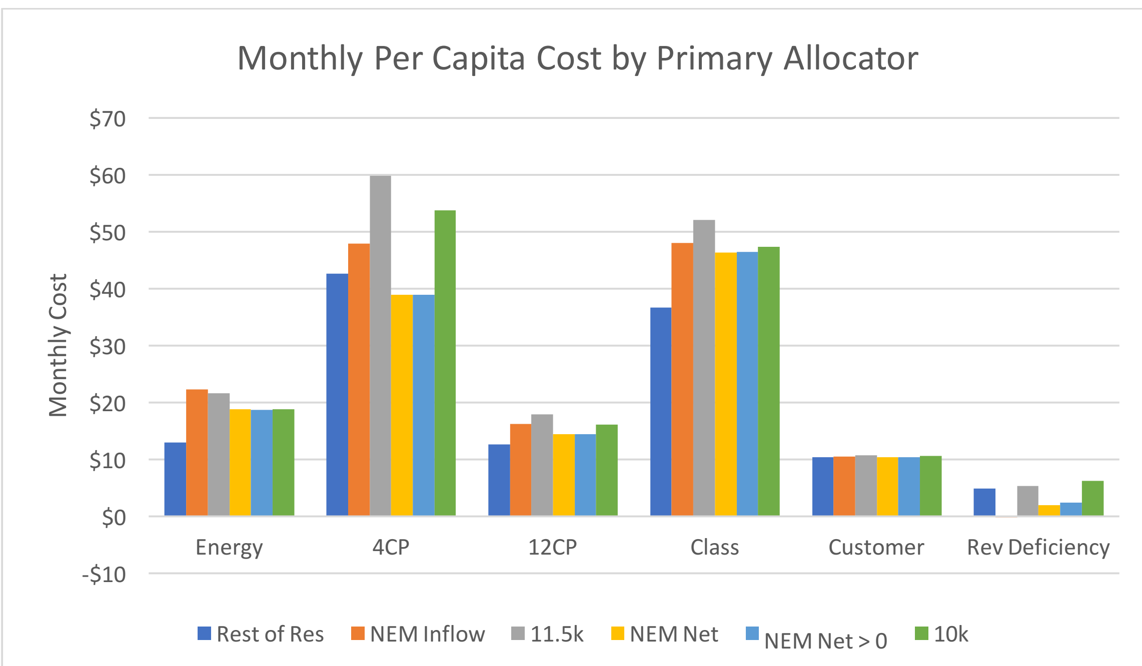

Figure 16 - CCOSS Total Cost per Customer

Q. WHAT DO YOU OBSERVE ABOUT THE RESULTS THAT FIGURES 15 AND 16 ILLUSTRATE?

A. On a per kWh basis, the NEM Inflow customer grouping is 16.3% less costly to serve than non-NEM customers.

Q. IS THAT RESULT MERELY CONSISTENT WITH THE GENERAL TREND THAT HIGH-USE CUSTOMERS ARE LESS EXPENSIVE TO SERVE ON A PER KWH BASIS THAN AVERAGE-USE CUSTOMERS?

A. No. The NEM Inflow result is also 16.3% lower than the cost for the non-NEM 11.5k customers *of similar size*. The reduction in cost between the NEM Inflow and 11.5k customers comes primarily from the reduction in the 4CP demand allocator, with a smaller contribution from the classpeak allocator, the 12CP allocator, and the revenue deficiency.

NEM Net and NEM Net > 0 have somewhat higher costs per kWh than the NEM Inflow grouping. While all the energy and demand allocators for the NEM Net customers did fall compared to the NEM Inflow customers, the reduction in annual energy usage (which sets the cost per kWh) was slightly larger than the reduction in allocated costs, resulting in a slightly higher per kWh cost. Regardless, the NEM Net results still show a 11.0% (NEM Net) and 13.3% (NEM Net > 0) reduction over the non-NEM customers.

The NEM Net customers are also much less costly to serve than the corresponding non-NEM 10k customers. The allocated costs for 4CP are much lower for the NEM Net customers with the rest of the allocators similar. The 10k customer group underearns by a larger margin as well; the 10k revenue deficiency is $6.27, compared to just $2.00 to $2.50 for the NEM Net customers.

Q. HOW DOES THE TOTAL COST PER CUSTOMER COMPARE?

A. Figure 17 below show the total cost per customer for each group. In this figure, the total cost allocated to each customer group is divided by the number of customers in that group. While Figure 15 above showed the results in terms of cost per kWh of energy served, Figure 17 shows the result in terms of cost per customer. This is an analogue to the total monthly bill of a customer independent of their usage.

When you look at all customer groupings, NEM Inflow customers are more costly to serve than non-NEM customers. However, NEM customers, who tend to be larger customers, are actually less expensive to serve than the similarly-sized 11.5k customers. The

NEM Net customer grouping is remarkably close to the non-NEM customers, and is considerably lower than the correspondingly-sized 10k customers.

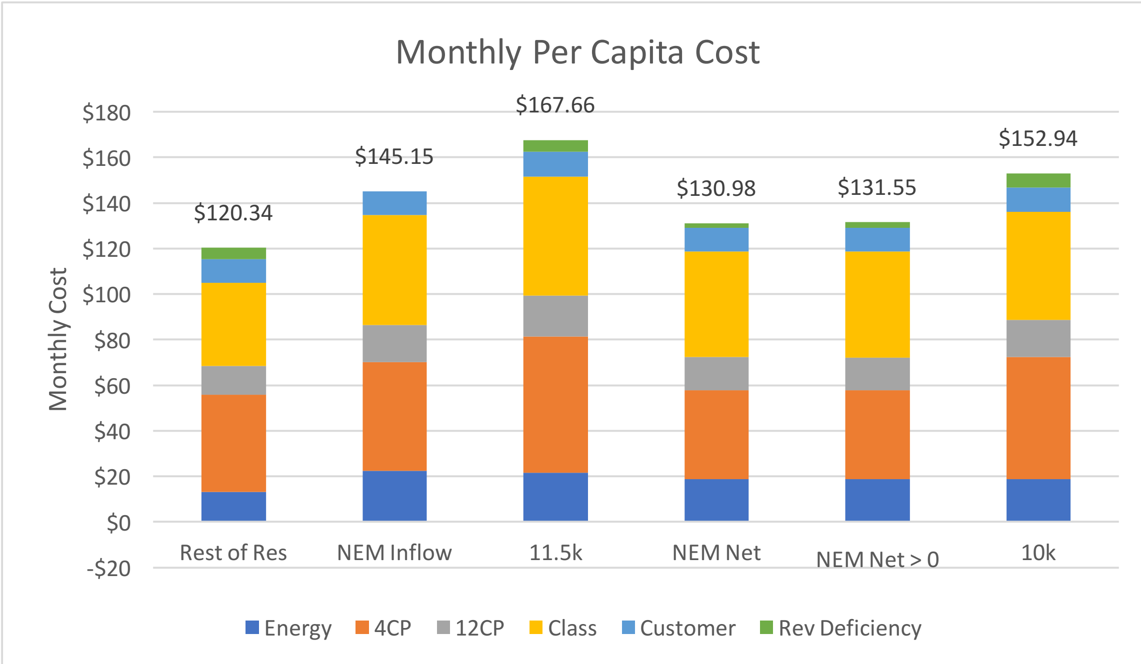

Figure 17 - Monthly Per Capita Cost

Q. DOES THE COST TO SERVE NEM CUSTOMERS SCALE WITH USAGE IN THE SAME WAY AS WITH THE OTHER CUSTOMER GROUPINGS?

A. No. Figure 18 below plots the combination of monthly per capita costs and monthly per capita CCOSS usage. There is a nearly linear relationship between the non-NEM Rest of Res, 10k, and 11.5k customer groups, which reflects the fact that most costs scale roughly linearly with usage (the exception being customer costs). This line increases roughly $0.165 per kWh of additional usage, which is (not coincidentally) very close to the proposed variable residential rate of $0.161 per kWh.

The NEM Net, NEM Net > 0, and NEM Inflow results are significantly below this line and again show a nearly linear relationship between monthly costs and usage. In this case, the line is lower and flatter, increasing at a rate of $0.107 per kWh. Notably, this value is substantially below the variable retail rate, suggesting that larger NEM customers are overcharged even more than smaller NEM customers.

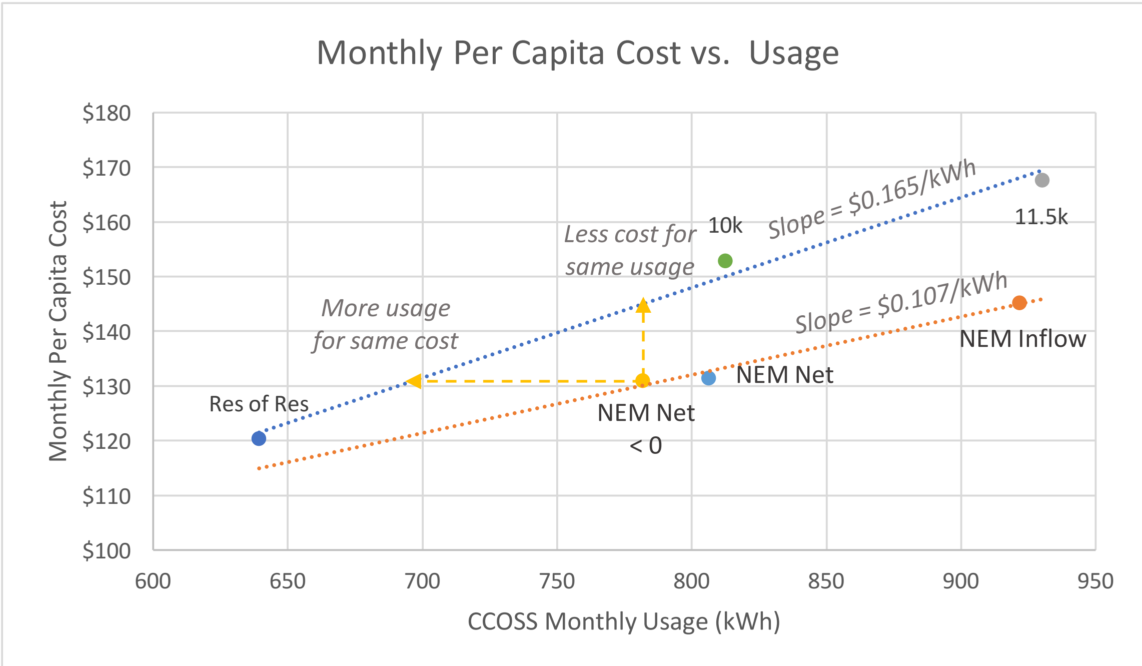

Figure 18 - Monthly Per Capita Cost vs. Usage

These results could be interpreted in two ways. The first is that for a given level of usage, NEM customers are less costly to serve than corresponding non-NEM customers (moving vertically to non-NEM line). The second is that NEM customers can use more energy than non-NEM customers without increasing the cost to serve them (moving horizontally to non-NEM line). At the same time, the incremental cost per kWh served is substantially lower for NEM customers than for non-NEM customers. The data suggests that, regardless of interpretation, NEM customers at any given level of consumption prove less costly to serve than non-NEM customers.

Q. DID YOU REPEAT THIS ANALYSIS USING THE COMPANY'S PROPOSED "89/0/11" 4CP ALLOCATOR?

A. Yes. As could be anticipated based on the underlying load characteristics, moving from the 75%/25% demand/total energy weighting to an 89%/11% demand/total energy weighting favors the NEM customer group even more as they have substantially lower 4CP demands than non-NEM customers. While non-NEM residential customers see an increase in their costs, the NEM customers see a decrease. NEM Inflow is now 17.9% less than the rest of the residential class, while the NEM Net results decrease further to a 12.9% (NEM Net) and 15.3% (NEM Net > 0) reduction over the non-NEM customers. Figures 19, 20, and 21 below duplicate previous charts using the Company's proposed 89/0/11 4CP allocator.

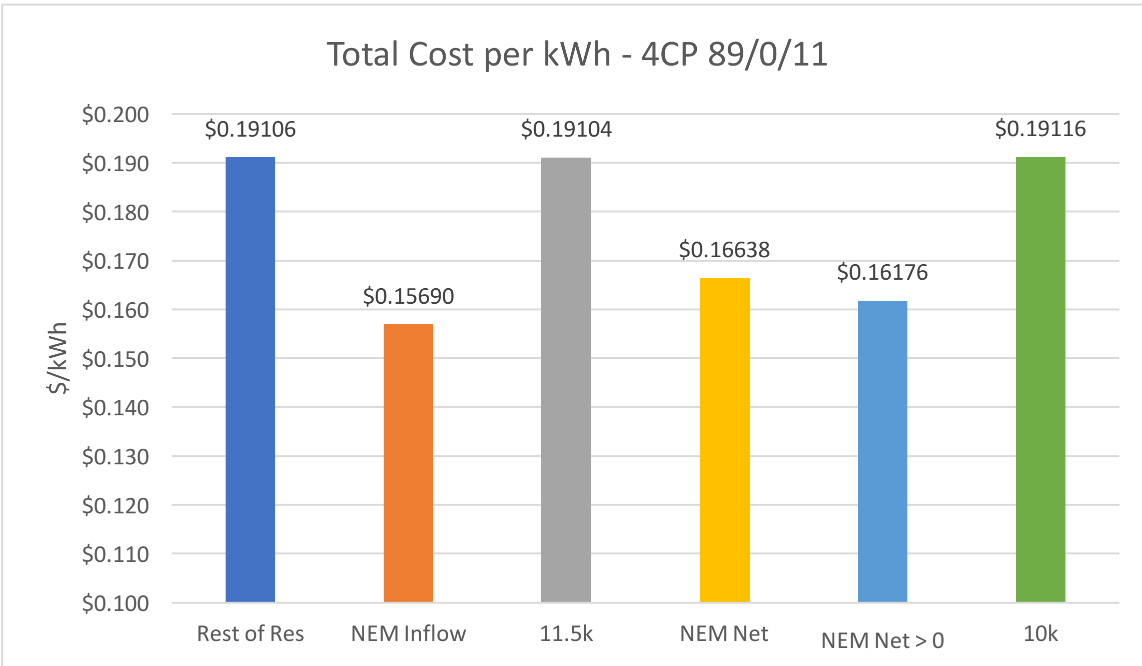

Figure 19 - CCOSS Total Cost per kWh – 4CP 89/0/11

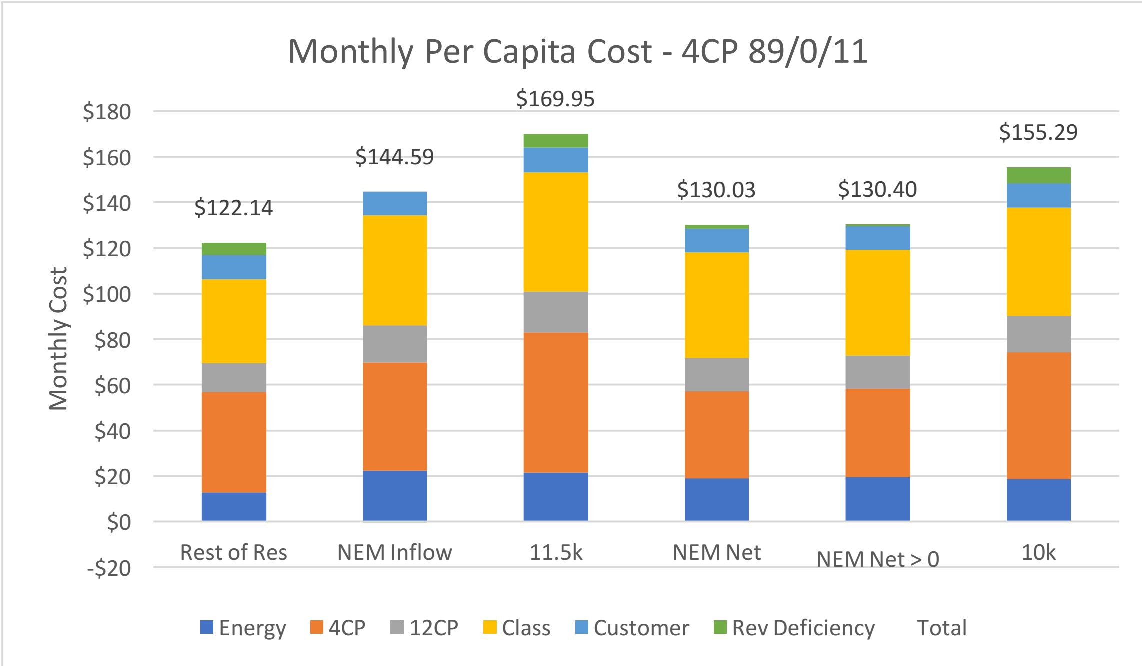

Figure 20 - Monthly Per Capita Cost – 4CP 89/0/11

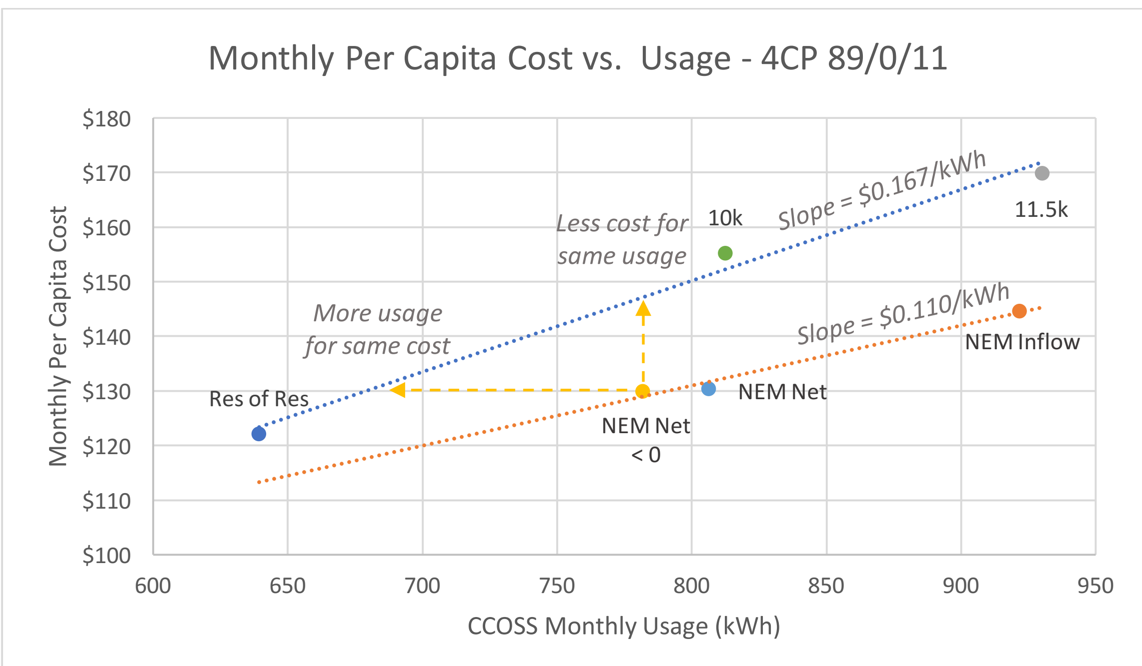

Figure 21 - Monthly Per Capita Cost vs. Usage – 4CP 89/0/11

Q. WHAT IS THE MAGNITUDE OF THE DIFFERENCE BETWEEN THE CCOSS RATES AND BILLS FOR THE CUSTOMER GROUPS?

A. The difference between the NEM Inflow customer cost per kWh and non-NEM customer cost per kWh is $0.03073 and $0.03415 under the 75/0/25 and 89/0/11 4CP allocator, respectively. One can calculate the impact on each customer grouping by taking the difference between their bill on their own cost rate and their bill on the non-NEM cost rate. Table 7 below shows these results for both 4CP demand allocators.

	Rest of Res	**NEM Inflow**	**11.5k**	**NEM Net**	**NEM Net > 0**	**10k**
2018 CCOSS usage (kWh)	7,671	11,058	11,158	9,378	9,674	9,749
75/0/25 CCOSS Rate	$0.18824	$0.15752	$0.18823	$0.16759	$0.16318	$0.18827
Bill at rate	$1,444	$1,742	$2,100	$1,572	$1,579	$1,835
Bill at “Rest of Res” rate	$1,444	$2,082	$2,100	$1,765	$1,821	$1,835
Delta	**$0**	**$340**	**$0**	**$194**	**$242**	**$0**
89/0/11 CCOSS Rate	$0.19106	$0.15690	$0.19104	$0.16638	$0.16176	$0.19116
Bill at Cust Group rate	$1,466	$1,735	$2,132	$1,560	$1,565	$1,863
Bill at “Rest of Res” rate	$1,466	$2,113	$2,132	$1,792	$1,848	$1,863
Delta[48]	**$0**	**$378**	**$0**	**$231**	**$283**	**-$1**

Table 7 - CCOSS Annual Bill Results

The result is stark. Under the Company’s current proposal (NEM Inflow in CCOSS at the 89/0/11 4CP allocator), the average NEM customer is charged $378 per year or $31.50 per month more than their cost-of-service-equivalent rate. Even if one were to maintain the 75/0/25 4CP allocator, shift to a NEM Net approach (which nets hourly inflow and outflow in the CCOSS), and use monthly net billing for the total monthly inflow and outflow – none of which is proposed by the Company in this case – the average NEM customer would still be overcharged by $194 per year or $16.17 per month. Contrast this to the non-NEM customers 11.5k and 10k customers groups, for whom the annual difference is effectively zero. Put another way, the bill that these customers pay is exactly in line with their cost-of-service-equivalent rate scaled by their usage.

[48] Delta may not match due to rounding.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE COST TO SERVE NEM CUSTOMERS AS COMPARED TO NON-NEM CUSTOMERS?

A. Using the Company's own CCOSS model, it is unequivocally true that NEM customers are less costly to serve than non-NEM customers. Whether comparing on a per kWh basis that mirrors the retail rate design, or comparing monthly per capita costs to per capita usage, NEM customers are less expensive to serve. This trend holds true under either the 75/0/25 or 89/0/11 4CP allocator methodologies. The reduction in cost is primarily due to the substantially lower 4CP demand that NEM customers place on the system, with smaller cost reduction contributions from lower 12CP demand.

Billing NEM customers under the Company's current proposal will overcharge the average NEM customer by $378 per year. Even with a more appropriate structure (netting inflow and outflow in both the CCOSS and in billing), the non-NEM rate overcharges NEM customers by $194 per year.

V. A COST-BASED OUTFLOW CREDIT SHOWS THE VALUE OF EXPORTED GENERATION

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I discuss two alternative methods of calculating a cost-based outflow credit. I also calculate an adder to account for the lower cost of service that NEM customers have compared to non-NEM customers that should be considered in addition to the outflow credit.

Q. WHAT ARE YOUR PRIMARY CONCLUSIONS?

A. The Company's proposed outflow credit of retail power supply less transmission, which generally falls between \$0.084 / kWh and \$0.125 / kWh, dramatically undervalues outflow energy. I calculated two cost-based outflow credits and found that the appropriate credit was substantially higher. Under the straight CCOSS method, the cost to serve of the "outflow class" (or, in other words, the equivalent of the cost-based outflow credit) was \$0.28125 / kWh. Under a mapping of allocators to energy periods, the outflow credit was \$0.23957 / kWh. These values are relatively close to each other, and both much higher than the Company's proposal. I also calculated an "adder" of between \$0.02739 / kWh and \$0.05341 / kWh to return a portion of the savings from the reduction in cost to serve NEM customers compared to non-NEM customers.

A. Outflow Energy is Different than Inflow Energy

Q. THE DISCUSSION ABOVE RELATED PRIMARILY TO COST OF PROVIDING INFLOW ENERGY FLOW FROM THE COMPANY TO NEM CUSTOMERS. WHAT IS THE COMPANY'S PROPOSAL FOR THE OUTFLOW CREDIT FROM THE NEM CUSTOMERS TO THE COMPANY?

A. The Company proposes to credit outflow energy at the power supply less transmission rate of the retail tariff that the customer is taking service. As with the underlying tariffs, the outflow credit is seasonally and temporally differentiated. The proposed credits are listed in Table 8 below.[49]

[49] ex0220-Miller-1-3 and WP-1-25.xlsx

	Summer			Winter		
Description	Peak	Off Peak	Super Off Peak	Peak	Off Peak	Super Off Peak
Summer On-peak RSP	$0.125355	$0.084319	$0.084319	$0.088869	$0.088869	$0.088869
Smart Hours RSH	$0.125355	$0.084319	$0.084319	$0.095128	$0.086523	$0.086523
Night Time Savers RPM	$0.125355	$0.097334	$0.062420	$0.095128	$0.094440	$0.070323

Table 8 - Proposed Outflow Credits

Q. IS THERE ANY REASON THE COMMISSION COULD APPROVE AN OUTFLOW CREDIT THAT IS NOT EQUAL TO THE POWER SUPPLY LESS TRANSMISSION?

A. Yes. As JCEO witness Karl Rábago explains, the Company is not limited to proposing an outflow credit equal to retail power supply less transmission and the Commission has approved other outflow credit methodologies. I will not relitigate these issues here, but based on Mr. Rábago's testimony, it is clear that the Company may propose, and the Commission may approve, alternative outflow credits.

Q. WHAT ARE THE LOAD CHARACTERISTICS OF OUTFLOW ENERGY?

A. Because outflow is a function of both generation and customer load, outflow energy will vary from customer to customer. However, taking the average of the NEM customers' data reveals that outflow is most likely to occur in the months and hours when a DG customer's load is relatively low and solar output is relatively high. In aggregate, outflow peaks during the early afternoon of summer days before sloping down in the late afternoon. Figure 22 below shows the aggregate NEM outflow energy with an overlay of various peak energy definitions. There is substantial outflow during the CCOSS critical peak (2 – 6 PM) and rate design on-peak (2 – 7 PM) hours, and nearly all outflow falls within the CCOSS on-peak hour definitions (6 AM – 10 PM).

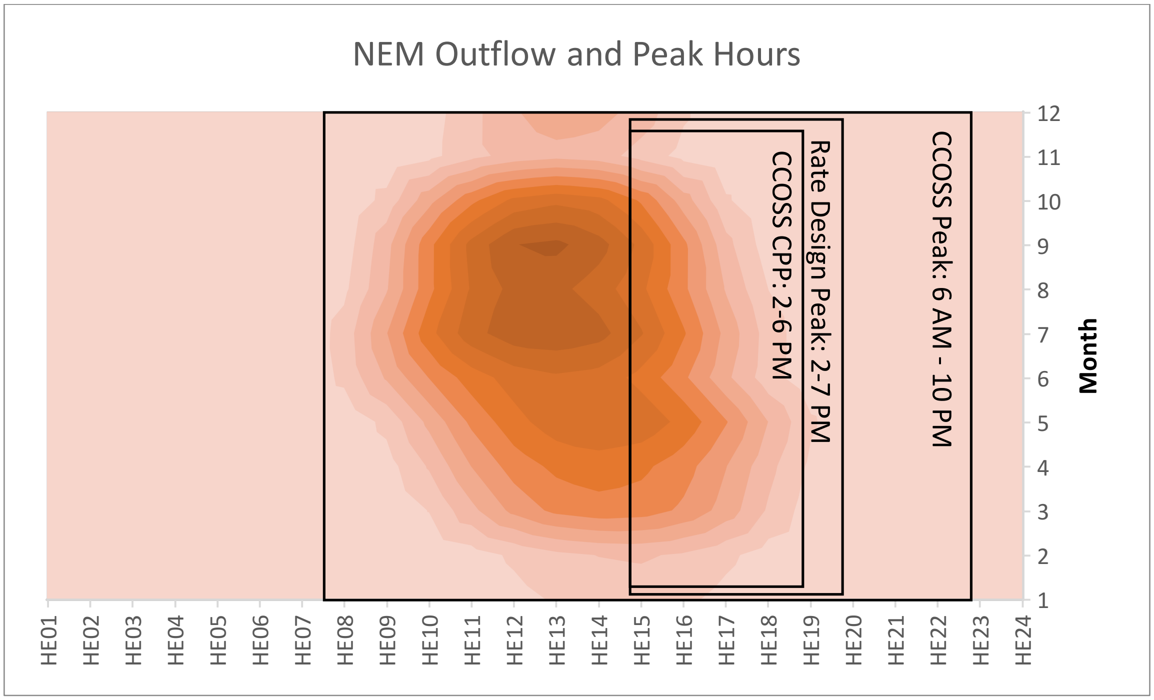

Figure 22 - NEM Outflow and Peak Hours

Figure 23 below compares the annual outflow energy by CCOSS category. Note that the CCOSS includes usage during weekdays in peak and CPP energy, so even though outflow is fully contained within the CCOSS on-peak hours, outflow during the weekend would be considered off-peak. Even so, the share of on-peak energy, summer on-peak energy, and critical peak energy is much higher for outflow energy than for either the residential class or the NEM inflow energy.

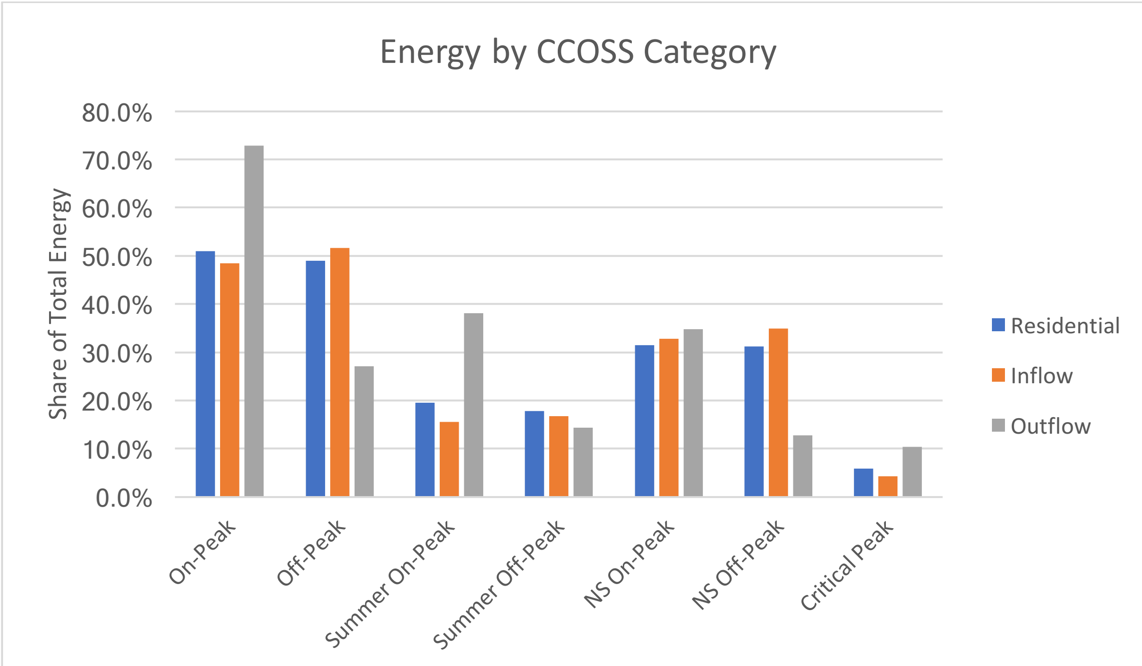

Figure 23 - Energy by CCOSS Category

Q. WHAT IS THE IMPLICATION OF THIS RESULT?

A. Outflow energy is more valuable than average energy. While the residential class (on which the retail rate design is based) is split roughly 50/50 between on-peak and off-peak energy, outflow energy is 73/27 towards on-peak outflow. Likewise, only 5.9% of residential energy occurs during the critical peak hours compared to 10.3% for outflow energy. Creating a credit for outflow energy that is based on the average retail value – even one with a peak period – is inappropriate.

Q. BUT IS IT NOT THE CASE THAT THE OUTFLOW TARIFF VARIES BASED ON THE RATE DESIGN PEAK PERIODS?

A. Yes, however the rate design periods are not designed to fully reflect the CCOSS model results. This is not a critique – it is almost never appropriate to translate CCOSS results into retail rate designs for inflow energy. However, to develop a cost-based outflow credit, one must look at the underlying costs from CCOSS model that correspond to the hours when outflow energy is produced.

Q. DID YOU CALCULATE AN ALTERNATIVE OUTFLOW CREDIT BASED ON THE CCOSS?

A. Yes. I produced two alternative outflow credit values based on the CCOSS. The first modeled a hypothetical customer class that had the load characteristics of the outflow energy from the NEM class and used the CCOSS result. The second was calculated by apportioning residential class costs from the various allocators (e.g. 4CP, classpeak) to different energy periods (e.g. critical peak, summer on-peak, all sales, etc.) and calculating the value that the outflow load shape produced. Both results demonstrate that the outflow energy from DG PV systems occurs during hours that produces a considerably higher-than-average value compared to the Company's proposal.

B. Outflow Credit based on Outflow Load Characteristics

Q. HOW DID YOU MODEL THE OUTFLOW ENERGY IN THE CCOSS?

A. Because the CCOSS was not structured to handle negative load, I modeled the outflow energy as a separate class as if the outflow energy were inflow energy. This will produce a cost to serve a hypothetical "customer group" that has the same load profile as the outflow energy. Using the same logic that the outflow credit rate should be the inverse of the cost rate, I propose the resulting CCOSS rate for all non-customer costs as the credit rate for outflow energy.

Q. ARE THE RETAIL RATES THAT THE COMPANY USES AS A BASE FOR THE OUTFLOW CREDIT RATE EQUIVALENT TO THE CCOSS COST RATE?

A. Not exactly. The Company used the CCOSS to produce a revenue requirement for the residential class, and subsequently derived rates that were designed to collect this revenue. However, the volumetric portion of the retail rate is necessarily similar to the CCOSS cost rate as they attempt to collect the same revenue from the same overall sales.

Q. DID YOU MAKE ANY ADJUSTMENTS TO THE OUTFLOW DATA?

A. Yes, I made one change from how I performed the analysis on the inflow customer groups. When modeling the various inflow customer groups above, I used the default "classpeak" calculation that found the maximum single hour of class load regardless of the rest of the classes or the system peak, as is consistent with modeling the rest of the CCOSS classes. For the outflow data, however, I set the classpeak value equal to the load during the same hour as the residential class peak. This better represents the contribution to cost reductions for distribution costs than using a separate outflow value.

Q. WHAT WAS THE IMPACT OF THIS ADJUSTMENT?

A. The independent classpeak of the outflow energy of 3,102 kW occurred on HE13 on October 18, 2018. By contrast, the outflow during the residential peak hour of HE16 on July 1, 2018 was much lower at 780 kW. By using the lower value, the CCOSS allocates less classpeak cost to the outflow "class", resulting in lower total costs and a lower cost per kWh. Since the credit is the inverse of the cost per kWh, this actually reduces the resulting outflow credit value.

Q. WHAT CREDIT VALUE DID YOU GET USING THIS METHOD?

A. The CCOSS allocated a total cost of $633,547 to the outflow energy "class". When spread across the 2,252,564 kWh of outflow energy, this results in a cost – and thus credit – rate of $0.28125 / kWh of outflow energy.

C. Outflow Credit Based on CCOSS Time Periods

Q. PLEASE DESCRIBE THE SECOND METHOD YOU USED TO CALCULATE AN OUTFLOW CREDIT.

A. Instead of modeling the outflow energy shape in the CCOSS, the second method reallocated the full residential class costs to energy periods by allocator. This mapping concentrates production and transmission capacity costs in the time of use ("TOU") hours most likely to contain the peaks that drive those costs, and maps distribution costs to a broader set of hours to represent the need to delivery power over the course of the year. Energy and revenue deficiency are allocated to total sales.

Q. HOW DID YOU DETERMINE THE SHARES OF EACH COST TO ALLOCATE TO EACH TOU PERIOD?

A. I reviewed the Company's load data from 2012 through 2018 and determine what hours contained the classpeak, 4CP, and 12CP values. Table 9 shows the 12CP results, indicating a concentration of peak events during the CPP and on-peak TOU periods, with only one 12CP peak event in the seven years of data occurring in the off-peak hours.[50]

TOU Period	Hours	Summer	Non-Summer	Grand Total
CPP	2 PM – 6PM Weekdays	25	6	31
On Peak	6 AM – 10 PM Weekdays	2	50	52
Off-Peak		1		1
Grand Total		**28**	**56**	**84**

Table 9 - 2012-2018 12CP Events by TOU Period

Based on the frequency of these hours, I created a map between the allocators and the TOU periods. For the 4CP allocator, I maintained the 75%/25% demand/total energy split. The 75% portion for demand was allocated to the CPP, summer on-peak, and summer off-peak periods consistent with frequency of 4CP hours in each of the TOU periods. The 12CP was similarly allocated primarily to the CPP, summer on-peak, and winter on-peak TOU periods, with a lone hour going towards the summer off-peak TOU period.

All of the classpeak hours fell in the summer months, with five occurring during critical peak period ("CPP") hours and two occurring during on-peak hours. Classpeak costs were divided 50%/50% demand/total energy to reflect the mixed function of the distribution system; while the distribution system is built to handle class peak demand, it is also utilized to deliver energy throughout the year. The demand portion was further divided based on the CPP and on-peak split. Finally, energy and revenue deficiency costs were spread over total sales. Table 10 below shows the summary of these steps.

[50] The 4CP hours are simply the summer 12CP hours.

Allocators	Energy	4CP	12CP	Classpeak	Rev Deficiency
CPP		67.0%	36.9%	35.7%	
Summer On-Peak		5.4%	2.4%	14.3%	
Summer Off-Peak		2.7%	1.2%		
Non-Summer On-Peak			59.5%		
Non-Summer Off-Peak					
Total Sales	100.0%	25.0%		50.0%	100.0%
Total by Allocator	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Table 10 - TOU Period / Allocator Cross Reference

Q. WHAT WAS THE NEXT STEP IN THE ANALYSIS?

A. Having determined how to map the CCOSS allocators to TOU periods, the next step was to map the CCOSS cost results and determine a corresponding cost rate for each TOU period. This was done by multiplying the total cost of each allocator by the TOU fractions and calculating the final weighted average cost per kWh for that TOU period. These values are non-cumulative, so generation during a CPP hour would receive credit for the total sales rate, the on-peak rate, and the CPP rate. Customer costs are not allocated based on this method as they are collected through a fixed charge. Table 11 shows the result of this calculation.

	kWh	Energy	4CP	12CP	Class	Rev Deficiency	Total	Weighted Avg Rate
CCOSS Costs ($000)		$253,991	$829,991	$246,465	$713,465	$96,025	$2,139,937	
CPP	728,834,875	$0	$555,797	$90,957	$254,809	$0	$901,564	$1.23699
Summer On-Peak	2,431,216,771	$0	$44,464	$5,868	$101,924	$0	$152,256	$0.06263
Summer Off-Peak	2,222,423,009	$0	$22,232	$2,934	$0	$0	$25,166	$0.01132
NS On-Peak	3,914,076,443	$0	$0	$146,705	$0	$0	$146,705	$0.03748
NS Off-Peak	3,877,699,324	$0	$0	$0	$0	$0	$0	$0.00000
Total Sales	12,445,415,548	$253,991	$207,498	$0	$356,733	$96,025	$914,247	$0.07346

Table 11 - CCOSS Allocator Mapping and Cost Rate

Q. WHAT IS THE FINAL STEP IN THE ANALYSIS?

A. Having established the cost rates for each TOU period, the last remaining step is to multiply the outflow energy by period by these rates. The total is calculated, and an overall weighted average outflow rate is established. This rate is equal to $0.23957 / kWh, as shown below in Table 12.

Outflow	kWh	Weighted Rate	Value
CPP	232,330	$1.23699	$287,391
Summer On-Peak	859,071	$0.06263	$53,800
Summer Off-Peak	322,163	$0.01132	$3,648
Non-Summer On-Peak	782,676	$0.03748	$29,336
Non-Summer Off-Peak	288,654	$0.00000	$0
Total Sales	2,252,564	$0.07346	$165,475
Total			$539,649
Total Credit Rate			$0.23957

Table 12 - Calculation of Outflow Credit Rate

Q. WHAT DO YOU OBSERVE ABOUT THIS RESULT?

A. As with the pure CCOSS approach, this value is well above the Company's proposed outflow credit and demonstrates the Company's failure to reflect underlying costs in its proposed credit. I also note that more than half of the value of the annual outflow is associated with exports during the CPP hours. These are the exact hours when reducing load is most important given the frequency of 4CP, 12CP, and classpeak hours that fall into this time band. Finally, this value is similar to the rate calculated by plugging the CCOSS outflow load characteristics into the CCOSS.

D. An Outflow Adder Based on a Share of the Cost Savings from NEM Customers is Appropriate

Q. EARLIER IN YOUR TESTIMONY, YOU CALCULATED THAT NEM CUSTOMERS WERE LESS COSTLY TO SERVE AND THAT CHARGING NEM CUSTOMERS THE "REST OF RESIDENTIAL" RATE WOULD OVERCHARGE THEM. HOW CAN THIS BE ADDRESSED OUTSIDE OF SEPARATING NEM CUSTOMERS INTO THEIR OWN CLASS?

A. As discussed previously, I do not believe it is appropriate to separate NEM customers into their own cost of service class. However, it is clear from the Company's CCOSS that NEM customers are being overcharged relative to their usage patterns. One way to account for this is to provide an outflow credit adder that transfers to NEM customers a share of the total savings created from DG PV systems while leaving the remainder in place to reduce costs for all residential customers.

Q. HOW WOULD ONE CALCULATE SUCH AN ADDER?

A. I calculated earlier than the average NEM customer was being overcharged by $378 per year using NEM Inflow load characteristics under the Company's proposed 4CP 89/0/11 allocator in the CCOSS. This falls to $194 per year using NEM Net load characteristics in the CCOSS under the 4CP 75/0/11 allocator. From these values, one can calculate an adder that adjusts based on the final approach the Commission approves.

I recommend calculating the adder based on the return of 25% of the value created by NEM customers spread over the average outflow energy. This adder would encourage more DG installations, which would in turn reduce the cost per kWh of the entire residential class. Table 13 calculates this adder based on the various CCOSS scenarios, which ranged between $0.0274 / kwh and $0.0534 / kWh.

	4CP 75/0/25 CCOSS		**4CP 89/0/11 CCOSS**	
NEM CCOSS Treatment	Inflow	Net	Inflow	Net
Overcharge	$339.79	$193.72	$377.68	$231.41
25% Credit	$84.95	$48.43	$94.42	$57.85
Outflow kWh	1,768	1,768	1,768	1,768
Adder / kWh	**$0.04805**	**$0.02739**	**$0.05341**	**$0.03272**

Table 13 - NEM CCOSS Reduction Outflow Adder

Q. IS THERE PRECEDENT FOR THIS TYPE OF ADDER?

A. Yes. Many utilities implement a form of critical peak pricing. These rate designs either charge a very high rate during critical peak hours in exchange for a discounted rate during other hours, or provide a very high rebate per kWh based on a reduction in energy usage during peak hours.

Q. DOES THE COMPANY HAVE SUCH A PROGRAM?

A. Yes. It offers a Critical Peak Pricing rate for residential customers.[51] Customers on this rate will receive a 33% reduction in their summer off-peak rate (7 PM to 2 PM weekdays and all hours on weekends and holidays). In exchange, customers will be charged $0.95 / kWh for usage from 2 PM to 6 PM during days that the Company calls a CPP event.

[51] https://peakpowersavers.com/cpp

Q. PLEASE PROVIDE AN EXAMPLE OF OTHER UTILITIES THAT RUN A SIMILAR CRITICAL PEAK PRICING PROGRAM.

A. Baltimore Gas and Electric ("BGE") runs a critical peak rebate program called Smart Energy Rewards.[52] In this program, customers pay the same base rate, but receive a credit equal to $1.25 / kWh for energy reduction during CPP events from their baseline usage.

Both of these programs share a common goal: incenting customers to reduce their usage during key hours. The discount that one earns during off-peak hours on the Company's program and the credit that one receives on BGE's program represent a reward for such behavior. The costs for the discounts and credits do not exceed the total savings of the actions, so the rest of the residential class still benefits even if they do not take individual action to reduce their load.

This structure mirrors my proposed NEM CCOSS reduction outflow adder. The choice that a customer makes to install a DG PV system reduces the cost to serve entire residential class. Under the adder, part of this savings is returned to the NEM customer, just as a rebate or discount is provided to customers participating in the critical peak pricing programs.

Q. WHAT DO YOU RECOMMEND AS THE MOST APPROPRIATE OUTFLOW CREDIT RATE?

A. While I think the CCOSS outflow "class" and allocator / TOU mapping method both produce valid cost-based credit rates, I believe the allocator / TOU mapping method produces a more robust result and is consistent with keeping NEM and non-NEM customers in the same CCOSS class. By mapping costs driven by 4CP, 12CP, and classpeak demands to the TOU periods in which they tend to fall, the resulting cost rate properly blends the disparate portions of the CCOSS into one comprehensive set of rates. Applying these rates to the outflow energy patterns produces a weighted-average credit that appropriately values outflow energy contributions to reducing demands.

[52] https://www.bge.com/SmartEnergy/ProgramsServices/Pages/SmartEnergyRewards.aspx

I also recommend that an adder be applied to the outflow credit based on the specific CCOSS method that is approved. This adder represents one-quarter of the benefit that NEM customers bring to the entire residential class and has policy precedent from the Company's critical peak pricing program. Table 14 below presents my final recommendations based on the CCOSS method.

	4CP 75/0/25 CCOSS		**4CP 89/0/11 CCOSS**	
NEM CCOSS Treatment	Inflow	Net	Inflow	Net
CCOSS Allocator / TOU Mapping Rate	$0.23957	$0.23957	$0.23957	$0.23957
CCOSS Reduction Adder	$0.04805	$0.02739	$0.05341	$0.03272
Total Outflow Credit Rate	**$0.28762**	**$0.26696**	**$0.29298**	**$0.27229**

Table 14 - Final Outflow Credit Rate Recommendation

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A. My overall conclusion is that residential NEM customers are less costly to serve than non-NEM customers. I recommend that:

(1) The Commission should disregard the Brattle study upon which the Company relies to show the cost of service of residential NEM customers. The source data underlying the Brattle study was substantially incomplete and required much data processing. Even after cleaning, the data was starkly different than an updated version of the NEM customer data. Brattle improperly adjusted the Company's CCOSS model, and ultimately presented its results in a manner inconsistent with either the CCOSS or retail rate designs.

(2) As part of an interim DG Tariff, the Commission should adopt the residential outflow credit rate of **$0.23957 / kWh**,

(3) As part of an interim DG Tariff, the Commission should recognize an adder that ranges between **$0.02739 / kWh and $0.05341 / kWh** depending on the 4CP method and treatment of outflow energy in the CCOSS.

(4) The Commission should direct Consumers to undertake a Value of Solar study to quantify the appropriate outflow credit going forward.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-20697

DIRECT TESTIMONY

OF

CLAUDINE Y. CUSTODIO

ON BEHALF OF

THE ECOLOGY CENTER, ENVIRONMENTAL LAW & POLICY CENTER, GREAT LAKES RENEWABLE ENERGY ASSOCIATION, SOLAR ENERGY INDUSTRIES ASSOCIATION, AND VOTE SOLAR

June 24, 2020

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<u>List of Figures</u>

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Claudine Y. Custodio. My business address is 360 22nd Street, Suite 730, Oakland, CA 94612.

Q. On whose behalf are you submitting this direct testimony?

A. This direct testimony is on behalf of the Ecology Center, Environmental Law & Policy Center, Great Lakes Renewable Energy Association, Solar Energy Industries Association and Vote Solar (collectively, Joint Clean Energy Organizations or JCEO).

Q. By whom are you employed and in what capacity?

A. I serve as the Regulatory Research Manager at Vote Solar. In this role, I review regulatory filings, perform technical analyses, and draft testimony in public utility commission proceedings relating to distributed solar generation.

Q. What is Vote Solar?

A. Vote Solar is an independent 501(c)(3) non-profit working to repower the U.S. with clean energy by making solar power more accessible and affordable through effective policy advocacy. Vote Solar seeks to promote the development of solar at every scale, from distributed rooftop solar to large utility-scale plants. Vote Solar is not a trade group, nor does it have corporate members.

Q. Please describe your education and experience.

A. I have a Bachelor of Science in Environmental Resources Engineering from Humboldt State University and a Master of Science in Civil and Environmental Engineering from University of California at Berkeley. I also hold an Engineer-in-

Training certification from National Council of Examiners for Engineering and Surveying. I was a Senior Research Associate at Lawrence Berkeley National Laboratory (LBNL) from 2012 to 2015. While at LBNL, I worked on commercial and residential building databases and writing software to analyze building energy use for the OpenEIS project. I attended Michigan State University Institute of Public Utilities Accounting and Ratemaking Course in 2019. I am currently a Regulatory Research Manager at Vote Solar, where I conduct data analysis to support testimony in regulatory filings. A summary of my background and qualifications is included as Exhibit CEO-16 (CC-1).

II. PURPOSE OF TESTIMONY AND SUMMARY OF FINDINGS

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

A. My testimony presents my analysis of the residential class loads from Consumers Energy Company. Specifically, my analysis compares the electricity use of customers with distributed generation ("DG customers") against other residential customers' electricity use.

Q. Please summarize your findings.

A. I reach two main findings. First, I find that the DG customers' electricity use is within the range of variability in the residential class. Second, using cluster analysis, I find several customer types within the residential customer class where DG customers are grouped together with customers without DG. Based on these findings, I conclude that DG customers provide diversity in the residential class, and should not be classified as a group separate from other residential customers.

III. DISTRIBUTED GENERATION CUSTOMERS PROVIDE DIVERSITY WITHIN THE RESIDENTIAL CUSTOMER CLASS

Q. What will you cover in this section of your testimony?

A. In this section of my testimony, I will describe my analysis of Consumers' residential class loads, and explain my findings regarding DG customers' loads as compared to the load profiles of other customers in the residential class.

Q. What data did you use for your analysis?

A. I used the residential class load data and net metering delivered data that the Company provided in responses to data requests. The data consisted of 10,442 residential customers with hourly delivered load from January 1, 2018 to December 31, 2018 and 1,638 net metering customers. Prior to the analysis, I removed duplicate records from customers that appear in both datasets. I narrowed down the number of customers included in the analysis to reduce the influence of outliers and missing records. A count of records showed that none of the customers have a complete record for 2018. I limited the analysis to customers with records for 95% of the year or 8,322 hours of data. I also limited the analysis to customers with an annual total delivered load between 2,049 - 21,801 kWh, (therefore excluding the bottom 5% and top 5% for the residential class). Overall, I included 9,633 customers in total in the analysis, which includes 1,347 DG customers, or 14% of the analysis population.

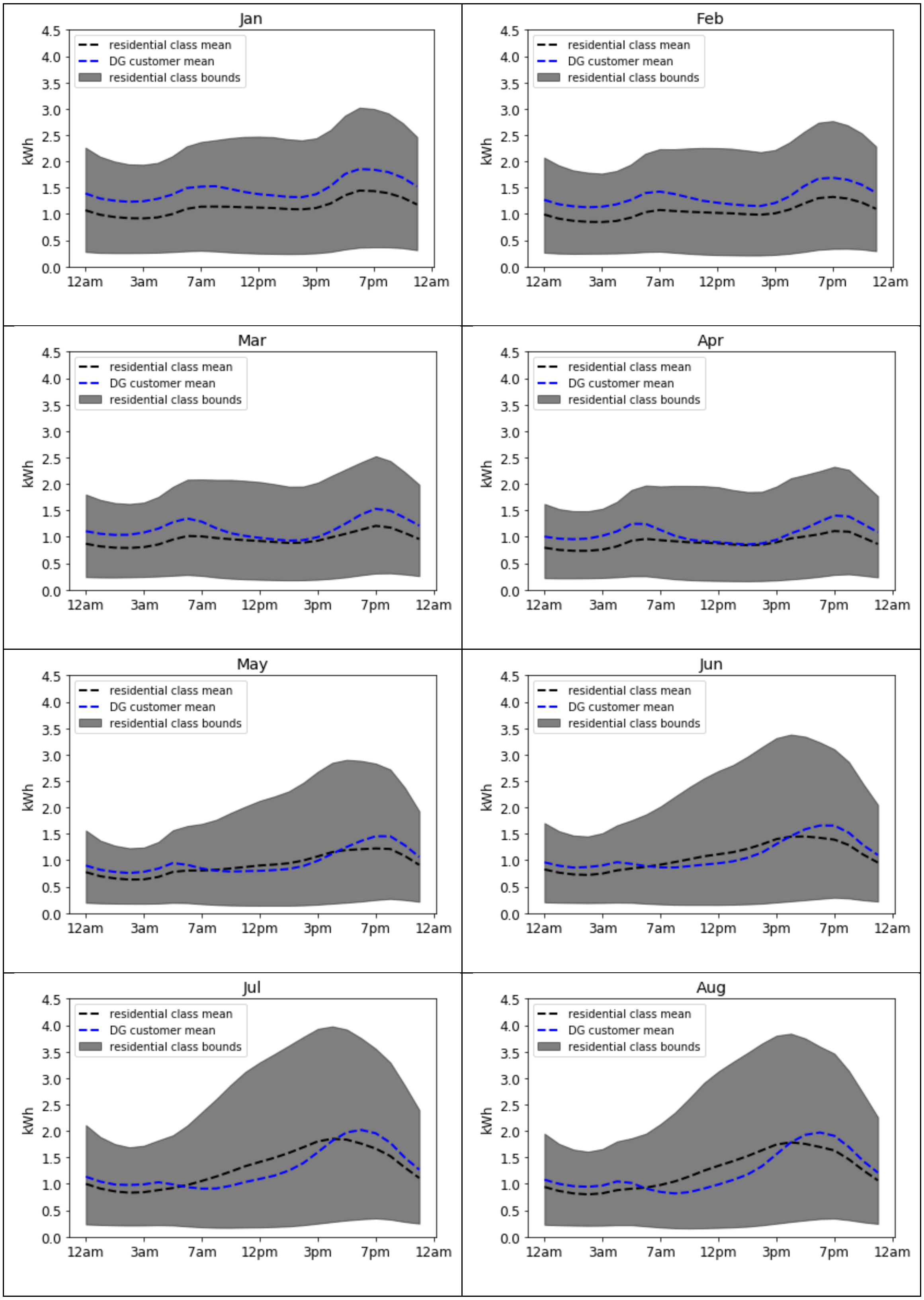
Q. How would you describe the average customer profile of the residential class?

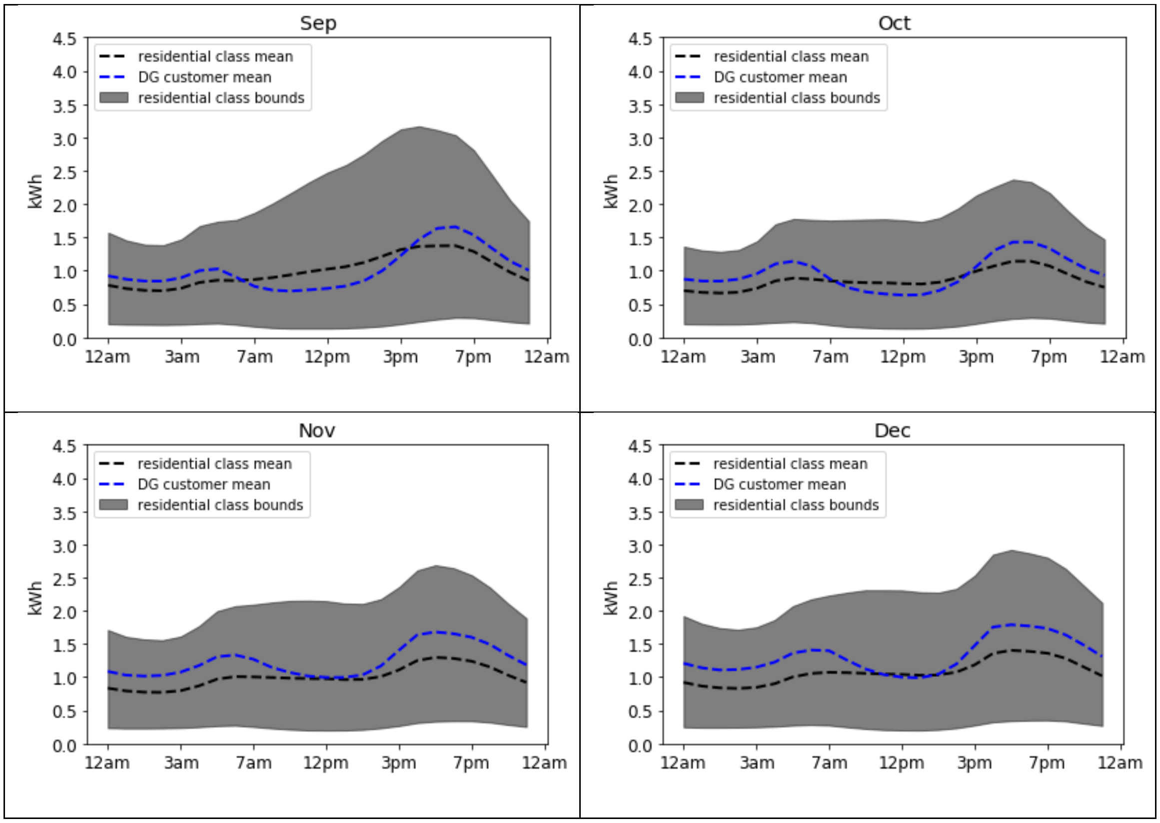
A. The residential customer class had two distinct load shapes that vary seasonally. The first load shape had two peaks, a peak early in the morning around 6 am that persists throughout the day and another peak in the evening around 7 pm . This load shape is observed 7 months out of the year. The second load shape has a single peak around 5pm. This load shape is observed from May until September. I provide a graph of the residential class mean, black dash line, and the 10% and 90% of the load values as a gray area in Figure 1. The range of customer loads is between 0.13 kWh to 4 kWh.

Q. How would you describe the electricity load of DG customers?

A. I calculated the hourly average for DG customers and plotted the result with the residential class data. The graphs in Figure 1 show the average for DG customers, blue dash line, is slightly above the average of the residential class, but still below 90th percentile of energy use. In the months of May to June, the mean load of DG customers tracks closely with the mean of the residential class. DG customer load shape is characterized by two peaks, one at 7 am and one between 6 - 7 pm , and a trough midday. The midday trough is at or below the residential class mean for most of the year except for January and February.

Figure 1: Electricity Use Profile of Residential Customer Class





Q. What conclusions can you draw from comparing load profiles of customers with and without DG?

A. I can conclude that there is a wide range of load profiles in the residential class. The DG customer load is within the range of variability of the residential class. In addition, the average load for DG customers is close to the average load of the residential class during certain months of the year. This shows that DG customers provide diversity within the residential customer class.

IV. <u>CLUSTER ANALYSIS SHOWS A VARIETY OF LOAD SHAPES WITHIN THE RESIDENTIAL CUSTOMER CLASS</u>

Q. What will you cover in this section of your testimony?

A. In this section, I will discuss cluster analysis, and what it reveals about DG customers relative to the overall residential customer class.

Q. Are there statistical methods to find organic load shapes within a residential class dataset?

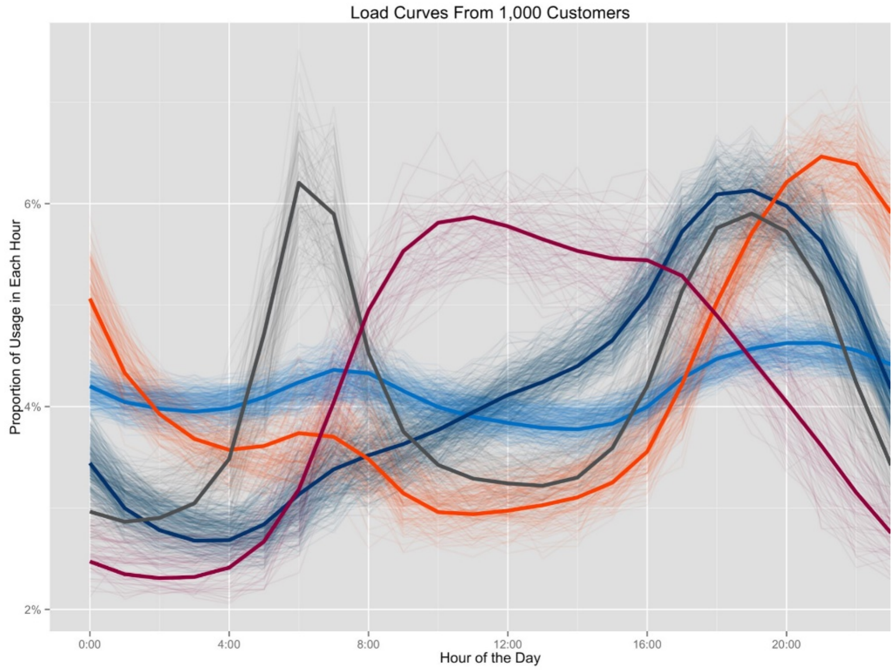
A. Yes, there are machine-learning algorithms that can statistically group samples based on shared characteristics.

Q. What other studies use analytical methods to find organic load shapes within the residential class?

A. I am aware of three studies that are relevant to my testimony.

The first study done by Opower in 2014 analyzed 812,000 utility customers from three major US cities. The results defined five weekday load profiles with peaks during different times of the day. The figure below shows the five “load archetypes” with the gray curve showing a morning and evening peak (“the coffee makers”), the “late afternoon peakers” shown in dark blue contrast with the late evening peakers in orange. There is also the relatively flat profile in bright blue and in magenta a group of customers that have a long peak period starting in the late morning until the afternoon.

Figure 2: Residential Load Curves identified by Opower Study[1]

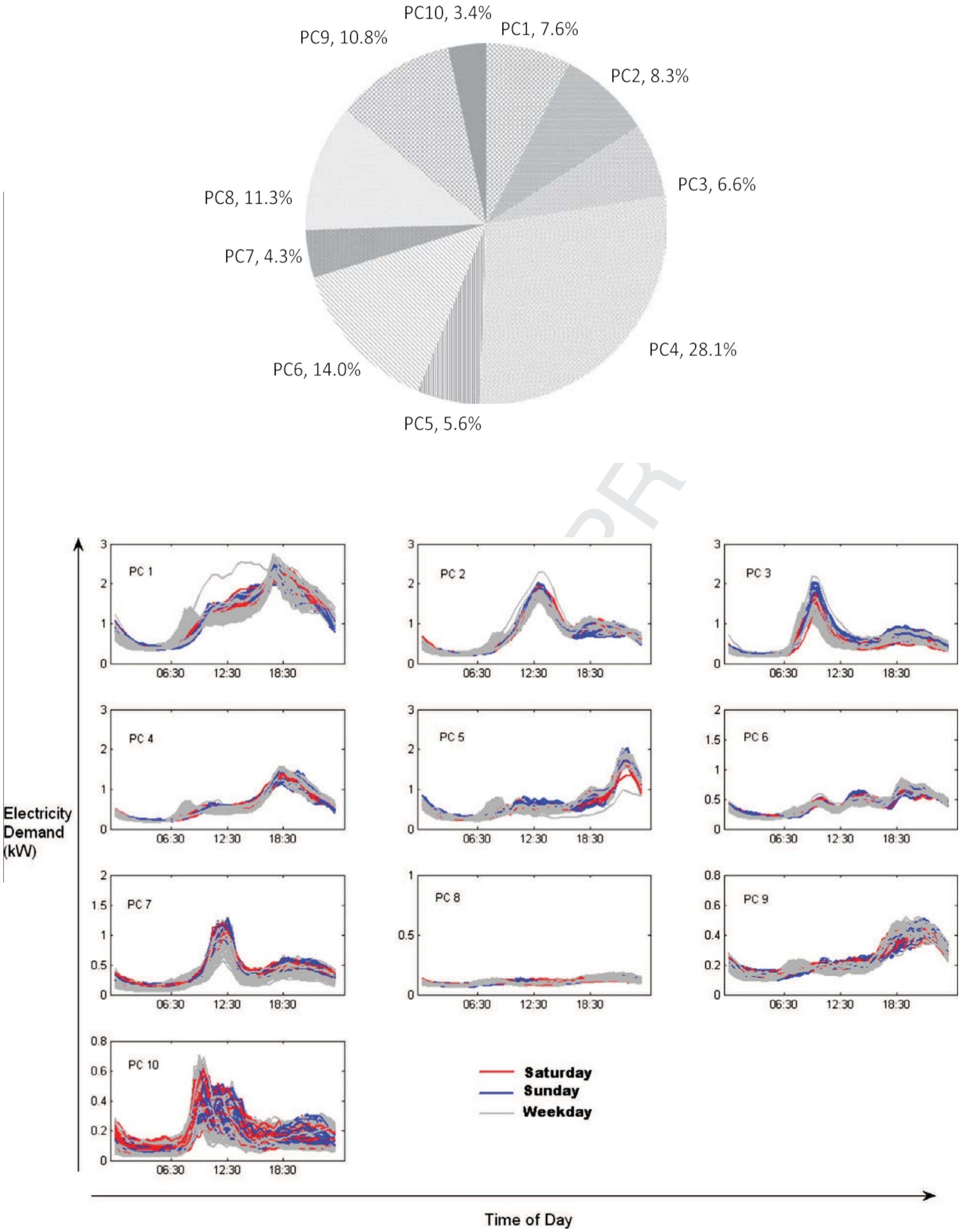


Source: Opower (2014)

The second study done by McLoughlin et. al. from the Dublin Energy Lab in 2014 analyzed 4,000 residential customers in Ireland and applied three different clustering methods to the data. The results are ten profile classes. The figure below shows the sample size and shape of the profile classes.

[1] Barry Fischer, *We plotted 812,000 energy usage curves on top of each other. This is the powerful insight we discovered*, Oracle: Utilities Blog (Oct. 13, 2014), https://blogs.oracle.com/utilities/load-curve-archetypes (attached as Exhibit CEO-17(CC-2)).

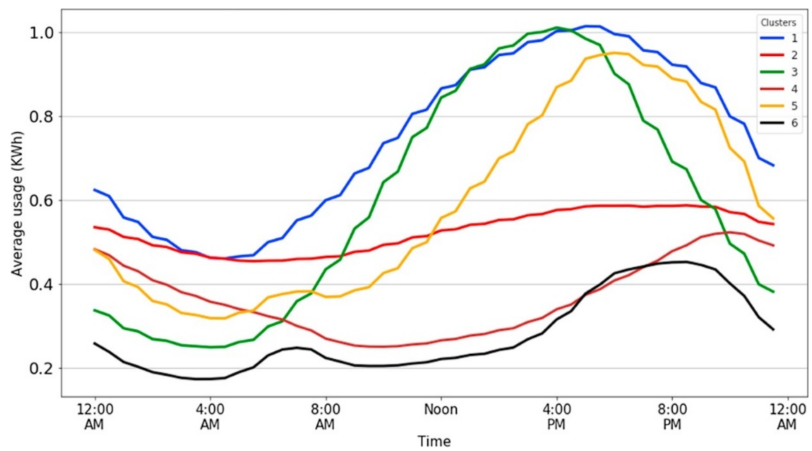
Figure 3: Profile Classes Identified by the Dublin Energy Lab Study[2]



[2] McLoughlin F et al. *A clustering approach to domestic electricity load profile characterisation using smart metering data*. Appl Energy (2014), http://dx.doi.org/10.1016/j.apenergy.2014.12.039 (attached as Exhibit CEO-18 (CC-3))

The third study done by Zethmayr and Makhija from Citizens Utility Board in 2019 applied k-means clustering to 2.5 million Illinois customers. They also used census data to relate location and demographics with the cluster load shapes. The results are six clusters shown in the figure below.

Figure 4: Load Curves Identified by the Citizens Utility Board Study[3]



All three studies were able to find multiple organic load shapes within the residential class. These load shapes can vary in overall magnitude, peak height, and peak times.

Q. Please describe k-means clustering algorithm.

A. K-means clustering is an unsupervised machine-learning algorithm that groups data by minimizing their distance from centroids. The algorithm first defines an initial set of centroids within the dataset, then calculates the inertia of the results. Inertia is the "sum of the squared distances of the samples to the closest cluster

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[3] Zethmayr, J and Makhija, R.S. *Six unique load shapes: A segmentation analysis of Illinois residential electricity consumers.* The Electricity Journal (2019) https://doi.org/10.1016/j.tej.2019.106643 (attached as Exhibit CC-4)

center”[4]. The algorithm updates the location of the centroids to minimize the distance of datapoints from each centroid.

The algorithm requires “features” and the “number of clusters” as inputs. The algorithm results in labels corresponding to a specific centroid for each datapoint and the locations of the centroids.

Q. How did you apply k-means clustering to the Company’s data?

I calculated the optimal number of cluster groups using the Elbow Method. The k-means algorithm is applied to the dataset with an increasing number of cluster groups. The plot of the inertia as a function of the number of cluster groups is shown in Figure 5. The optimal number of cluster groups is the point where the inertia decreases linearly, or when the distances of each datapoint to the centroids slightly vary. The results of the Elbow Method show 4 cluster groups as the optimal number for the Company’s dataset.

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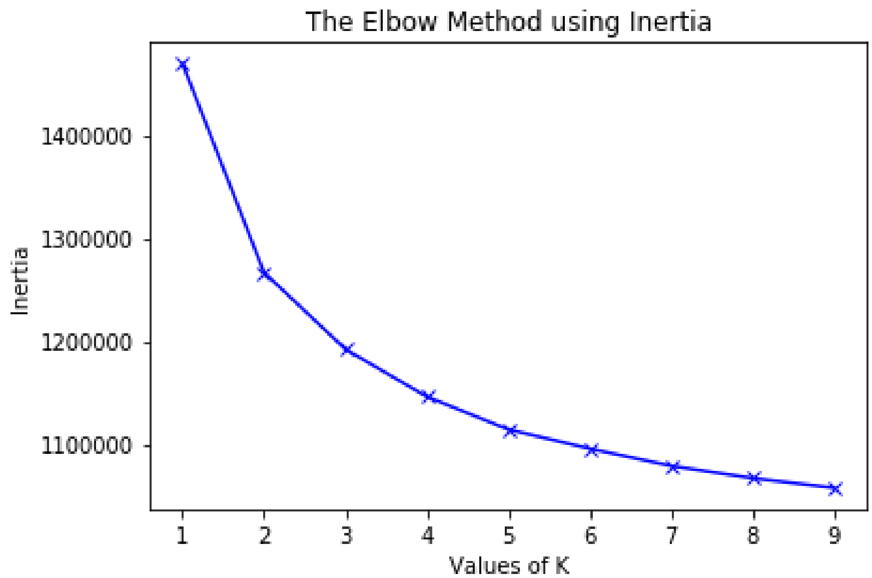
[4] scikit-learn developers, *K-means*. User Guide: Unsupervised Learning: Clustering (2007). https://scikit-learn.org/stable/modules/clustering.html#k-means

Figure 5: Results of the Elbow Method



Q. Please describe the result of the k-means clustering algorithm.

A. The algorithm produced four cluster groups. The cluster centers are shown in Figure 6 as monthly 24-hour percentages of maximum load. The cluster centers are algorithm results that represent where each cluster group coverges. All the groups have two-peak profiles for most of the year and single-peak profiles in July to September; higher peaks are also observed during these three months.

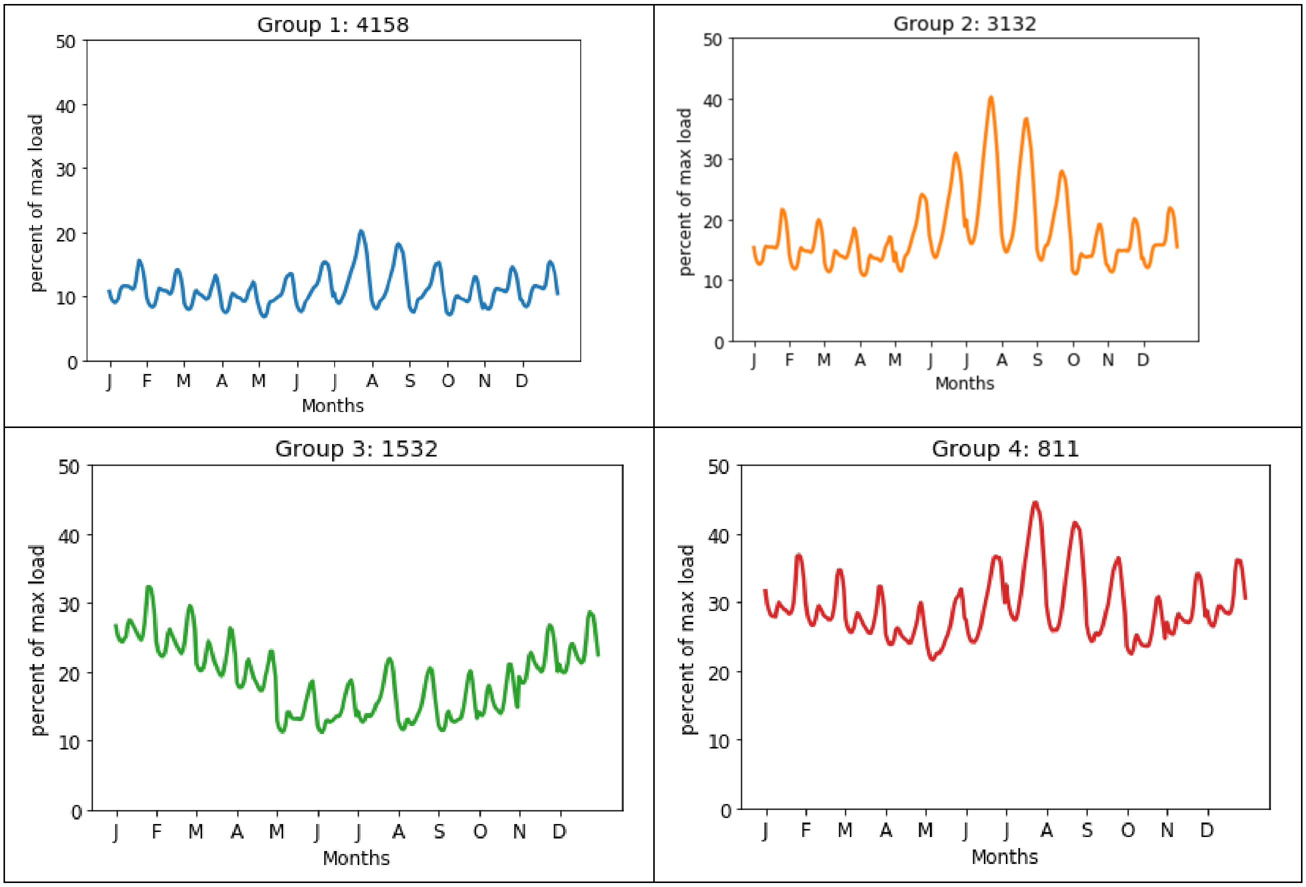
The first group has 4,158 members or 43% of the total dataset. The group has low use, between 10 - 20% of the maximum load. Peak use for these customers are higher around the June to September.

The second group has 3,132 members or 32% of the dataset. The group has the highest difference between the peak and the base use during summer and fall. The use range is between 12 - 40% of the maximum load.

The third group has 1,532 members or 16% of the dataset. The main characteristic for the group is higher base use in winter and spring. The peaks are typically below 30% of maximum load. The group range is between 10 –32% of the maximum load.

The fourth group 811 members or 8% of the dataset. The final group has the highest base use of all the profiles at 22% of the maximum load. The group has a similar decrease in base percentage in the summer months as Group 3. The group range is between 22 – 45% of the maximum load.

Figure 6: Load Shapes Resulting from Cluster Analysis

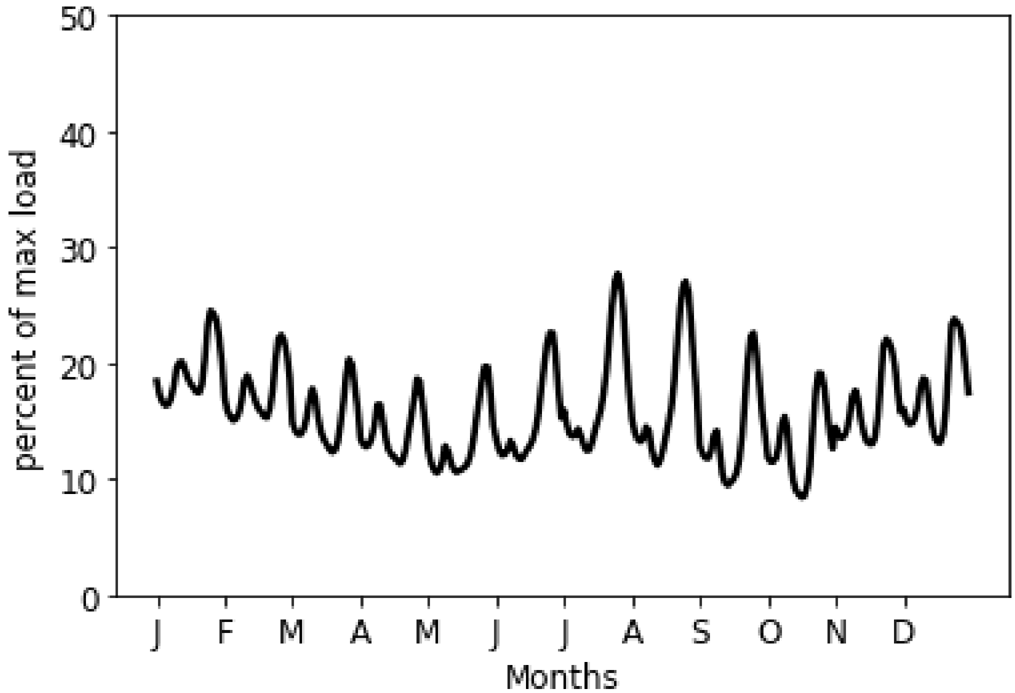


Q. How does the DG load shape compare to the cluster analysis load shapes?

A. The DG load shape has a base at 10% of the maximum load and summer peaks at 30% of the maximum load as shown in Figure 8. In general, DG customers have the same morning peak and evening peak for most of year with the highest peaks in the summer.

The profile shares characteristics from the cluster analysis load shapes. The peak percentage does not go above a certain percentage like Group 1. Also, there is an increase in base percentage in the winter months like Groups 3 and 4.

Figure 7 Monthly 24-Hour Overview of DG Customers



Q. What is the distribution of DG customers in each cluster group?

A. There are 621 DG customers in Group 1, 449 DG customers in Group 2, 174 DG customers in Group 3, and 103 DG customers in Group 4. A summary of the customer counts in each cluster group is in Table 1. There is no one group that has a majority DG customers. In fact, the proportion of DG customers to the number of members in each group is similar.

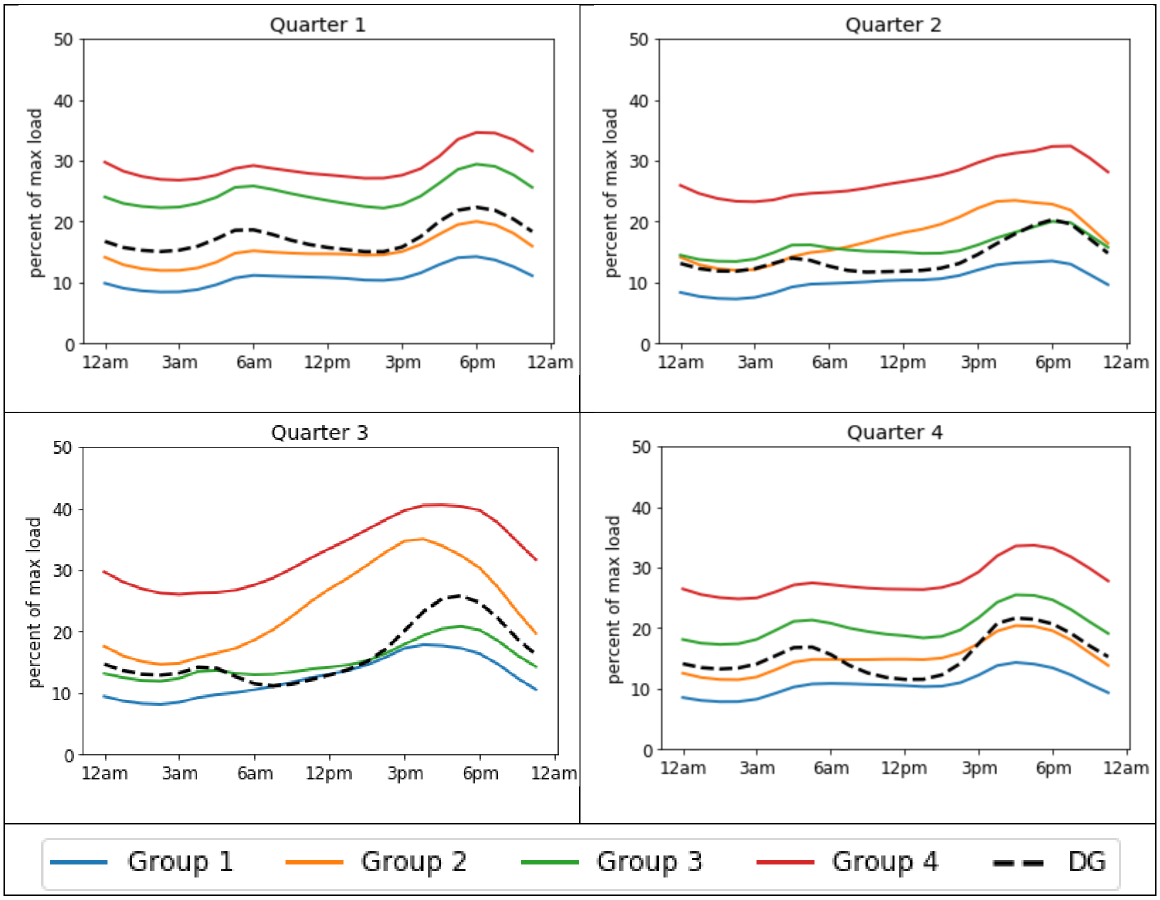
Table 1: Number of Customers per Cluster Group

Cluster Group	Customer Count	Percent of Sample	DG Customer Count	Percent of DG in Group
1	4158	43%	621	15%
2	3132	33%	449	14%
3	1532	16%	174	11%
4	811	8%	103	13%

Q. How do DG customers compare to each cluster group?

A. Figure 7 shows the quarterly load profiles for each of the cluster groups and DG customers. The DG customer profile is somewhere between the Group 1 and Group 3 cluster profiles. In addition, the peaks of the DG customer profile are close to the evening peak of Group 3 in Quarter 2, the morning peak of Group 3 in Quarter 3, and the peaks of Group 2 in Quarter 4. The midday troughs of the DG customer profile are closer to the Group 1 profile.

Figure 8 Comparison of Cluster Analysis Load Shapes and DG Customers



Q. Based on the results of the k-means cluster analysis, would it be reasonable to consider DG customers as a group separate from the rest of the residential class?

A. No, it would not. The results of the k-means cluster analysis show diversity of usage profiles within the residential class. The algorithm did not isolate the DG customers into their own group separate from the other members of the residential class. Nor did the algorithm classify all the DG customers into a single group. The results show DG customers have varied use profiles and share characteristics with other customers in the residential class.

V. <u>CONCLUSIONS AND RECOMMENDATIONS</u>

Q. What are your overall conclusions regarding the Company's residential distributed generation customers?

A. Distributed generation customers in the Company's residential class fall well within the range of variability of residential customers and should not be classified as a separate group. DG customers have average use only slightly above the residential class mean and, in some months, equal to the mean. In addition, the cluster analysis shows a variety of use profiles within the residential class. Usage profiles of DG customers are not in a separate cluster group, but are distributed in all 4 of the statistically determined groups.

DG customers' electricity use is not that different from other residential class customers. To the extent that the DG customer use varies from the average residential customer, they contribute to class diversity just like other customer sub-groups.

Q. Does this conclude your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the Application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief.	)))))	Case No. U-20697

DIRECT TESTIMONY OF
DR. GABRIEL CHAN

ON BEHALF OF

THE ECOLOGY CENTER, ENVIRONMENTAL LAW & POLICY CENTER, GREAT LAKES RENEWABLE ENERGY ASSOCIATION, SOLAR ENERGY INDUSTRIES ASSOCIATION, AND VOTE SOLAR
.

June 24, 2020

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I. INTRODUCTION AND WITNESS QUALIFICATIONS

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

A. My name is Gabriel Chan. I am an Assistant Professor at the University of Minnesota and Chair of the Science, Technology, and Environmental Policy area at the Humphrey School of Public Affairs, located at 301 19th Ave. S, Minneapolis, Minnesota.

Q. On whose behalf are you testifying?

A. I appear here in my own personal capacity as an expert witness on behalf of the Ecology Center, Environmental Law and Policy Center, Great Lakes Renewable Energy Association, Solar Energy Industries Association, and Vote Solar (the Joint Clean Energy Organizations, or "JCOE") and not on behalf of my employer, the University of Minnesota.

Q. Please describe your academic and work experience.

A. I have been an academic researcher and analyst in energy policy at the state, federal, and international level for over 10 years. I received my PhD in Public Policy from the Harvard Kennedy School in 2015 and have been an Assistant Professor of Public Affairs at the University of Minnesota since then. I have participated regularly in Minnesota regulatory proceedings related to the community solar program and the Value of Solar tariff over the past three years as an expert commenter and witness before the Minnesota Public Utilities Commission and the Minnesota legislature. I have published 16 peer-reviewed publications and over a dozen technical reports related to energy and environmental policy. A detailed CV is attached as Exhibit CEO-20 (GC-1).

Q. Are you sponsoring any exhibits as part of your direct testimony?

A. Yes, I am sponsoring the following exhibits as part of my direct testimony:

- CEO-20 (GC-1), which is the curriculum vitae of Prof. Gabriel Chan.

- CEO-35 (GC-2) which is a presentation on the Minnesota Distributed Solar Value Methodology by the Minnesota Department of Commerce. Minnesota Department of Commerce. 2014. *MN Distributed Solar Value Methodology*. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={007DDF1B-C60D-4D37-8066-275A67968CCD}&documentTitle=20143-97059-01

- CEO-36 (GC-3), which is a report on the Minnesota Value of Solar Methodology. Minnesota Department of Commerce. 2014. *Minnesota Value of Solar: Methodology*. Prepared by Clean Power Research. http://mn.gov/commerce-stat/pdfs/vos-methodology.pdf

- CEO-37 (GC-4), which is a report on Value of Solar by the National Renewable Energy Laboratory. Taylor, Mike, et al. 2015. *Value of Solar: Program Design and Implementation Considerations*. National Renewable Energy Laboratory. Technical Report NREL/TP-6A20-62361. https://www.nrel.gov/docs/fy15osti/62361.pdf

- CEO-38 (GC-5), which is a meta-analysis report on net metering and distributed solar costs benefit studies by ICF. 2018. Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar. https://www.icf.com/-/media/files/icf/reports/2019/icf-nem-meta-analysis_formatted-final_revised-1-17-193.pdf

II. PURPOSE, SUMMARY OF CONCLUSIONS AND RECOMMENDATIONSFGC

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

A. Through my testimony, I summarize the experience of establishing a methodology for a Value of Solar (VOS) tariff in Minnesota, offer reflections on the implementation of that methodology since its establishment in 2014, and suggest lessons learned from that process that have relevance to Michigan and this proceeding. Next, I explain the feasibility of establishing a robust Distributed Generation (DG) tariff for Consumers Energy Company customers based on equitably compensating DG customers for the full value of their DG system. I offer this opinion based on the Minnesota experience of establishing a VOS that compensates customers for the value of distributed solar to the utility, its customers, and society. Finally, I agree with witness Rabago's recommendation that the Commission direct Staff to lead a stakeholder process to develop a framework for a comprehensive Value of Solar[1] analysis for Michigan. I recommend that such a process should seek consensus on the principles for a Value of Solar framework. This process should rely on the established principles to identify options and best practices for the specification of a calculation methodology by engaging a diverse set of stakeholders, including utilities, third-party developers, environmental nonprofits, ratepayer advocates, representatives of the public, and neutral third-party technical experts. Further, I concur with witness Rabago's recommendation that the Commission order Consumers Energy ("the Company") to evaluate the costs and benefits of DG deployment and operations in its service territory based on the comprehensive VOS analysis because such an analysis would provide a just and reasonable approach to valuing the outflow of DG production for Consumers Energy customers.

[1] I use the term "Value of **Solar**" throughout my testimony because that term is commonly-used in Minnesota and several other jurisdictions where such studies have been undertaken. However, a VOS study and tariff can be equally relevant and applicable to non-solar distributed generation technologies when designed properly to account for different generation profiles of other forms of distributed generation or distributed energy resources.

Q. At a high level, why is Minnesota's VOS tariff relevant to Michigan and this proceeding?

A. While the Minnesota legislative and policy context is not identical to that in Michigan applicable to Consumers Energy, the goals of Minnesota statute and the principles adopted by the Minnesota Department of Commerce to establish a VOS in Minnesota are closely aligned to Michigan's legislation and staff recommendations. Specifically, Minnesota's statute requires that the VOS compensate customers for the value of distributed solar to the utility, its customers, and society. This goal directly aligns with Michigan statute[2] for establishing "rates equal to the cost of providing service …ensur[ing] that each class, or sub-class, is assessed for its fair and equitable use of the electric grid." In the MPSC staff report[3], the notion of "fair valuation" for DG was specified as including "two parts: (1) an avoided capital and energy cost; and (2) all other avoided cost or benefit elements such as avoided distribution line losses, transmission and distribution costs, avoided air emission and environmental costs, the solar-fuel price hedge, and reactive supply and voltage controls." Each of these elements of "fair valuation" have been considered in the Minnesota implementation of a VOS tariff that meets Minnesota statutory goals. Therefore, I believe that the Minnesota experience developing and implementing a VOS tariff is relevant to this proceeding.

Q. What are your primary conclusions and recommendations?

A: A Value of Solar approach to compensating DG outflow from Consumers Energy customers would meet Michigan's statutory requirement of establishing an "equitable

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[2] Michigan statute Sec. 6a(14), Sec. 11(1) of Act 341.

[3] Report of the MPSC Staff Study to develop a Cost of Service-Based Distributed Generation Program Tariff." February 21, 2018. https://www.michigan.gov/documents/mpsc/MPSC_Staff_DG_Report_with_Appendices_614779_7.pdf

cost of service based" distributed generation tariff. Minnesota's first-in-the-nation statewide methodology for a VOS tariff methodology applicable to public utilities is generally recognized as a successful framework for valuing distributed generation. The development of Minnesota's methodology can be instructive for Michigan. From an equity standpoint, a VOS allows for inclusive consideration of impacts on all members of the public. And while there are uncertainties in some of the specific values that DG can create, the Minnesota experience demonstrates that implementation of a VOS that considers a large set of costs and benefits can be feasibly implemented. In implementing a VOS, it is important to keep in mind that the "perfect should not be the enemy of the good" and the public good can be served with a well-designed VOS with a transparent and inclusive stakeholder process that enables continued iteration over time.

Based on my review of the evidence in this proceeding, my experience engaging in and observing the Minnesota development of a Value of Solar tariff, and the findings and conclusions I have reached in this testimony, I make the following recommendations to the Commission:

- Direct Staff to lead stakeholders in development a framework for a comprehensive Value of Solar analysis for Michigan that clearly guides assessment of the "fair and equitable use of the electric grid" as inclusive of all benefits to ratepayers, the utility, and society—including environmental benefits.
- Order Consumers Energy to evaluate the costs and benefits of DG deployment and operations in its service territory based on the comprehensive VOS analysis methodology to be used as the tariff for outflow DG generation.

- Implement an interim rate based upon the analysis conducted by Witness Kevin Lucas until such time as a VOS analysis can be completed.

III. MINNESOTA'S EXPERIENCE WITH ESTABLISHING A VALUE OF SOLAR METHODOLOGY AND TARIFF

Q. Please provide background context for Minnesota's experience with establishing a VOS tariff.

A. Minnesota was the first state to adopt legislation directing the establishment of a Value of Solar (VOS) tariff to compensate distributed solar generators[4]. In 2013, the Minnesota legislature passed an omnibus jobs, economic development, housing, commerce, and energy bill (HF 729[5]). Notably, Article 10 of the bill established several solar energy provisions, including a 1.5% solar energy standard for the state's three investor-owned utilities and a community solar garden program for Xcel Energy. Article 9 of the bill (amending Minnesota Statute §216B.164) established several provisions related to distributed generation. Importantly, Article 9 established an "alternative tariff" to provide "compensation for resource value" that would replace aspects of the state's existing net metering rules and which would come to be known as the Value of Solar Tariff," or VOS tariff."

Q. How did compensation for solar generation in Minnesota change with the 2013 legislation?

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[4] Minnesota directly built off of the experience in developing a VOS tariff in Austin Energy. Many of the stakeholders engaged in the process to develop the VOS methodology in Minnesota who were from out of state had been involved in the Austin methodology. See https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={90E29DF3-90F1-4FD1-BA3A-30CA4BDC54F0}&documentTitle=20141-96033-01

[5] Minn. H.F. 729 (2013), available at: https://www.revisor.mn.gov/bills/text.php?number=HF0729&session=ls88&version=latest&session_number=0&session_year=2013; https://www.house.leg.state.mn.us/hrd/bs/88/HF0729.pdf

A. Before the passage of HF 729, qualifying solar generators in Minnesota were compensated for generation in excess of consumption and sold to the utility at either the utility's Avoided Cost or the utility's average retail rate. Under the 2013 law, the legislature ordered the Minnesota Department of Commerce to establish a methodology for calculating a VOS that would function as an "alternative tariff that compensates customers through a bill credit mechanism for the value to the utility, its customers, and society for operating distributed solar photovoltaic resources interconnected to the utility system and operated by customers primarily for meeting their own energy needs." This alternative tariff was to be made available as an option for Minnesota's three investor-owned utilities to compensate excess generation from qualifying solar facilities with capacity greater than 40 kilowatts and less than 1,000 kilowatts.

Q. At a high level, how does the Minnesota VOS tariff function?

A. Minnesota law establishing the VOS was designed to provide a framework for net billing, similar to that proposed in the inflow-outflow methodology recommended by MPSC staff[6]. Pursuant to the 2013 law, the VOS "credits the customer for all electricity generated by the solar photovoltaic device at the distributed solar value rate" and

[6] During the stakeholder process leading to the adoption of the Minnesota VOS methodology, some stakeholders raised concerns that Minnesota's legislation could be interpreted as establishing a "buy-all sell-all" framework. However, in comments in docket E999/M-14-65 on February 20, 2014, the Department of Commerce clarified that the Department's interpretation of statute was that the legislation did *not* establish a "buy-all sell-all" framework, but instead would require all consumed electricity from the utility to be purchased at the customer's applicable retail rate and credits for all distributed solar production at the VOS. This "tariff-related" issue was considered "not yet ripe" by the Minnesota Public Utility Commission in its order at the time of the methodology's approval on April 1, 2014 and was left for further tariff proceedings. As of June 2020, the VOS methodology has only been applied to generation from community solar gardens in Xcel Energy's territory. In practice, net-billing and buy-all, sell-all are equivalent constructs for generation from community solar. This is because community solar generation, by definition, occurs offsite from the point of consumption with offtake through "virtual metering" facilitated by community solar subscription contracts. As of June 2020, despite the legal ability to do so, no utility in Minnesota has opted to use the VOS as a replacement for net metering for on-site distributed solar generation in excess of on-site consumption.

maintains that solar adopters are charged for their consumption at the "applicable rate schedule for sales to that class of customer."

Minnesota statute also specifies that "a utility must enter into a contract with an owner of a solar photovoltaic device receiving [the VOS tariff] that has a term of at least 20 years, unless a shorter term is agreed to by the parties," and "an owner of a solar photovoltaic device receiving [the VOS tariff] must be paid the same rate per kilowatt-hour generated each year for the term of the contract."

Q. Have Minnesota utilities adopted the VOS tariff as a compensation option for all distributed generators?

A. No. At this point, only Xcel Energy, the state's largest utility, has sought approval for a VOS tariff, and applies it only to certain customers participating in its community solar garden program—which the 2013 omnibus bill established along with the VOS tariff. That bill required Xcel Energy to purchase all energy generated by community solar gardens at the VOS tariff once it was to be approved and either the VOS (a) exceeded the retail rate or (b) had been calculated for three years. In order to promote market stability and meet the statutory requirement of allowing for the "creation, financing, and accessibility of community solar gardens," Minnesota statute required that compensation default to the applicable retail rate for a customer if the calculated VOS was below the retail rate in the first two years of calculating the VOS.

Q. Please elaborate on how Xcel has applied the VOS tariff to community solar gardens.

A. Xcel Energy's community solar garden program began in 2015 with projects filled by subscribers receiving their applicable retail rate as compensation for their subscribed generation. New community solar projects applying for interconnection beginning in 2017 (in the third year after the VOS was first calculated) were filled by subscribers receiving compensation for their subscription's generation based on the most recently approved annual VOS calculation.[7] An important feature of the Minnesota VOS is that projects are locked into the VOS as calculated in the year they are approved for interconnection. The tariff applied to projects increases with inflation during commercial operation for 25 years, and while the calculated VOS is updated each year, new values only apply to new projects.

By the end of 2019, community solar project compensation broke down as Table 1 below describes:

Table 1: Community Solar Project Compensation in Minnesota by the end of 2019[8]

	Compensation at applicable retail rate (MW)	**Compensation at VOS (MW)**
Operational Projects	636	20
Projects in design, construction or study phase	51	205

Q. Please describe how the Minnesota Department of Commerce developed the Value of Solar methodology.

A. Prior to the 2013 legislation, the Minnesota Department of Commerce had regularly convened and engaged stakeholders on topics related to distributed generation. In October 2012, the state's largest investor-owned utility, Xcel Energy, presented its

[7] For additional information on community solar in Minnesota, see ILSR, MnSEIA, and Vote Solar. 2019. Minnesota's Solar Gardens: The Status and Benefits of Community Solar. https://votesolar.org/files/1315/5691/0323/VS-Minnesota-Solar_Gardens-2019-Report.pdf

[8] Xcel Energy. April 1, 2020. Compliance -- 2019 Annual Report, Community Solar Gardens Program in Docket No. E002/M-13-867. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={B0193771-0000-C513-BD6E-2C6DD7DFD833}&documentTitle=20204-161729-01

concerns with the existing net metering rules to the Department of Commerce's stakeholder group and proposed an alternative approach similar to a VOS tariff.[9]

Following passage of the 2013 legislation establishing the VOS, the Department of Commerce built on these stakeholder convenings more formally. The 2013 legislation establishing the VOS offered requirements for the Department of Commerce's process to establish the VOS methodology[10]:

> The department must establish the distributed solar value methodology […] no later than January 31, 2014. The department must submit the methodology to the commission for approval. The commission must approve, modify with the consent of the department, or disapprove the methodology within 60 days of its submission. When developing the distributed solar value methodology, the department shall consult stakeholders with experience and expertise in power systems, solar energy, and electric utility ratemaking regarding the proposed methodology, underlying assumptions, and preliminary data.

In compliance with 2013 law, the Minnesota Department of Commerce convened four workshops to develop a VOS methodology from September-November 2013, each with 100-150 participants representing a diverse set of interested parties, including utilities, third-party developers, environmental nonprofits, ratepayer advocates, representatives of the public, and regional and national neutral third-party technical experts.[11]

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[9] Minnesota Department of Commerce. January 31, 2014. Filing of the Minnesota Department of Commerce in Docket No. E999/M-14-65. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={90E29DF3-90F1-4FD1-BA3A-30CA4BDC54F0}&documentTitle=20141-96033-01

[10] Minnesota Statute §216B.164, subd. 10(e).

[11] A record of the agendas and participants in the stakeholder process is available at Minnesota Department of Commerce. January 31, 2014. Filing of the Minnesota Department of Commerce in Docket No. E999/M-14-65 https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={90E29DF3-90F1-4FD1-BA3A-30CA4BDC54F0}&documentTitle=20141-96033-01; and at Minnesota Public Utilities Commission. April 1, 2014. Order Approving Distributed Solar Value Methodology in Docket No. E999/M-14-65. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={FC0357B5-FBE2-4E99-9E3B-5CCFCF48F822}&documentTitle=20144-97879-01

In late 2013, the Minnesota Department of Commerce selected the firm Clean Power Research to support the development of the VOS methodology.[12] The Department of Commerce submitted its recommended methodology for the VOS in January 2014. Subsequently, stakeholders filed robust comments regarding whether the methodology complied with statute. In its March 2014 presentation of its recommended Value of Solar methodology, the Minnesota Department of Commerce stated that the "VOS provides a rigorous analytical foundation for valuing distributed solar energy that can be updated and adjusted over time […] to incorporate the best available practices."[13] The Minnesota PUC approved the Department's VOS methodology with three modifications (to the fuel price escalation factor, avoided distribution capacity cost, and the use of non-CO_2 environmental values) on April 1, 2014[14]. I have included the approved VOS methodology as Exhibit CEO-35 (GC-2) to my testimony.

Q. How did participating stakeholders view the VOS methodology development process that the Minnesota Department of Commerce established?

A. In general, stakeholders—including utilities, advocates, and technical experts—viewed the process favorably.

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[12] Clean Power Research is a private, non-partisan company focused on "research, consulting and software for solar prediction, energy valuation and program optimization." https://www.cleanpower.com/about-us/

[13] Minnesota Department of Commerce. March 4, 2014 before the Minnesota Public Utilities Commission. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={007DDF1B-C60D-4D37-8066-275A67968CCD}&documentTitle=20143-97059-01

[14] Minn. Pub. Util. Comm'n, Docket No. E999/M-14-65, Order Approving Distributed Solar Value Methodology (Apr. 1, 2014), available at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={FC0357B5-FBE2-4E99-9E3B-5CCFCF48F822}&documentTitle=20144-97879-01

Xcel Energy, the state's largest utility and the only utility to have calculated a VOS as of June 2020 stated[15]: "This methodology was preceded by months of thoughtful and constructive dialogue among stakeholders, including the Company [Xcel Energy], Department [of Commerce], solar developers, and many others."

The Union of Concerned Scientists, a national nonprofit dedicated to advancing responsible public policies in areas where science and technologies play a critical role stated[16], "The Department has made a significant contribution to the stakeholders' and policymakers' categorization and analytical approach to the value of distributed solar. This process has served Minnesota well." Joe Wiedman, a representative of the Interstate Renewable Energy Council, a nonprofit that conducts fact-based regulatory policy engagement and develops best practice research, reflected that Minnesota's VOS stakeholder process so far should be considered "the gold standard. The process Minnesota has set up is a really solid, transparent process. It's one of the best that I've [taken part in]."[17] Offering observations from an external observer's perspective, researchers at the National Renewable Energy Laboratory and the Lawrence Berkeley National Laboratory commented:[18]

> The U.S. State of Minnesota established a VoS tariff formulation process where stakeholders were able to review all aspects of the methodology

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[15] Minn. Pub. Util. Comm'n, Docket No. E999/M-14-65. Xcel Energy Comments (Feb. 13, 2014), available at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7b5D1AFDC4-B46B-4A5D-841F-852F33F87F38%7d&documentTitle=20142-96427-01

[16] Union of Concerned Scientists. February 19, 2014. Comments: Value of Solar Methodology in Docket No. E999/M-14-65. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={019E2ACA-DCEA-4092-A558-901A2A87516A}&documentTitle=20142-96595-01

[17] Haugen, Dan. 2013. "Minnesota's Day in the Sun for Determining the Value of Solar." https://www.greentechmedia.com/articles/read/minnesotas-day-in-the-sun-for-determining-the-value-of-solar

[18] Zinaman, Owen and Naim Dargouth. 2015. "A Valuation-Based Framework for Considering Distributed Generation Photovoltaic Tariff Design." https://www.nrel.gov/docs/fy15osti/63555.pdf

> before a final rate was set. While no true consensus was ever reached on the methodology employed (or the final tariff level, for that matter), the process nonetheless successfully garnered open dialogue and methodological transparency. As well, it will have enabled stakeholders to continue to meaningfully contribute to VoS proceedings as the tariff is periodically reevaluated.

Q. How has Xcel Energy's implementation of the VOS tariff in Minnesota evolved since the Minnesota PUC approved the methodology in 2014?

A. Since the Minnesota PUC approved the Department of Commerce's VOS methodology in 2014, Xcel Energy has sought and received approval for its implementation of the VOS methodology in four annual rounds in 2017 – 2020. In each round, Xcel Energy publicly posts most of the spreadsheet calculations for the VOS (some limited aspects are deemed trade secret and are not public) and the PUC invites public comments on Xcel Energy's implementation of the methodology.[19] Including approved and interim calculations, Xcel Energy has calculated a VOS 11 times under Docket No. E002/M-13-867. In the past two iterations of the VOS, the PUC has required additional transparency measures in Xcel Energy's calculation of the VOS, including requirements for the utility to identify all values that have changed and the impact of each change on the final VOS relative to the previous year.

The VOS for Xcel Energy approved by the Minnesota PUC for 2020 had a 25-year levelized value of 11.52 cents per kWh. The 2020 VOS for Xcel Energy set the following levelized values for the eight categories of avoided cost[20]:

[19] The most recent set of spreadsheets for the approved 2020 VOS are available in MPUD Docket E002/M-13-867, and were filed on November 6, 2019 and August 30, 2019 (note that attachments B-Q were finalized for the 2020 VOS in filings on 8/30/2019 and attachment A was separately finalized to calculate the 2020 VOS on 11/6/2019 for revisions to the avoided distribution cost component of the VOS).

[20] The Minnesota VOS frames the benefits of solar through eight "avoided costs," and while conceptually similar, these values are practically and operationally distinct from the institutionalized "Avoided Cost" as defined in other proceedings, such as those relevant to compensation for Qualifying Facilities as defined under the Public Utilities Regulatory Policy Act.

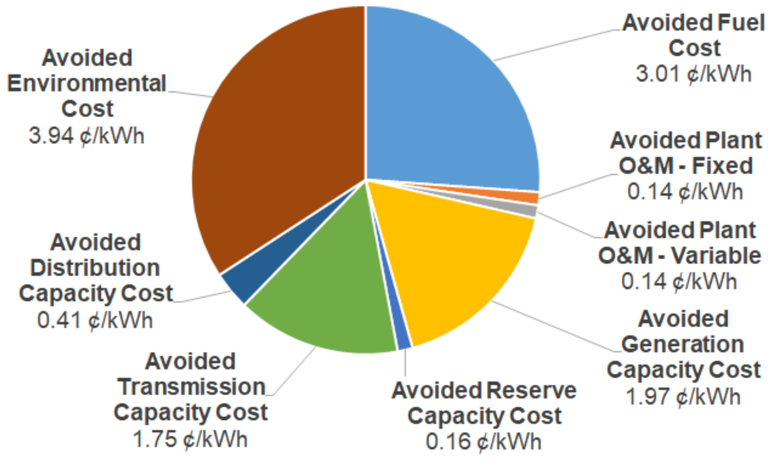

Figure 1. The 2020 Minnesota Value of Solar for Xcel Energy. Data source: Minnesota Docket No. E002/M-13-867.

Figure 2 below shows the evolution of the eight components of the VOS in each of the 11 calculations that Xcel Energy submitted in Minnesota PUC Docket No. E002/M-13-867.

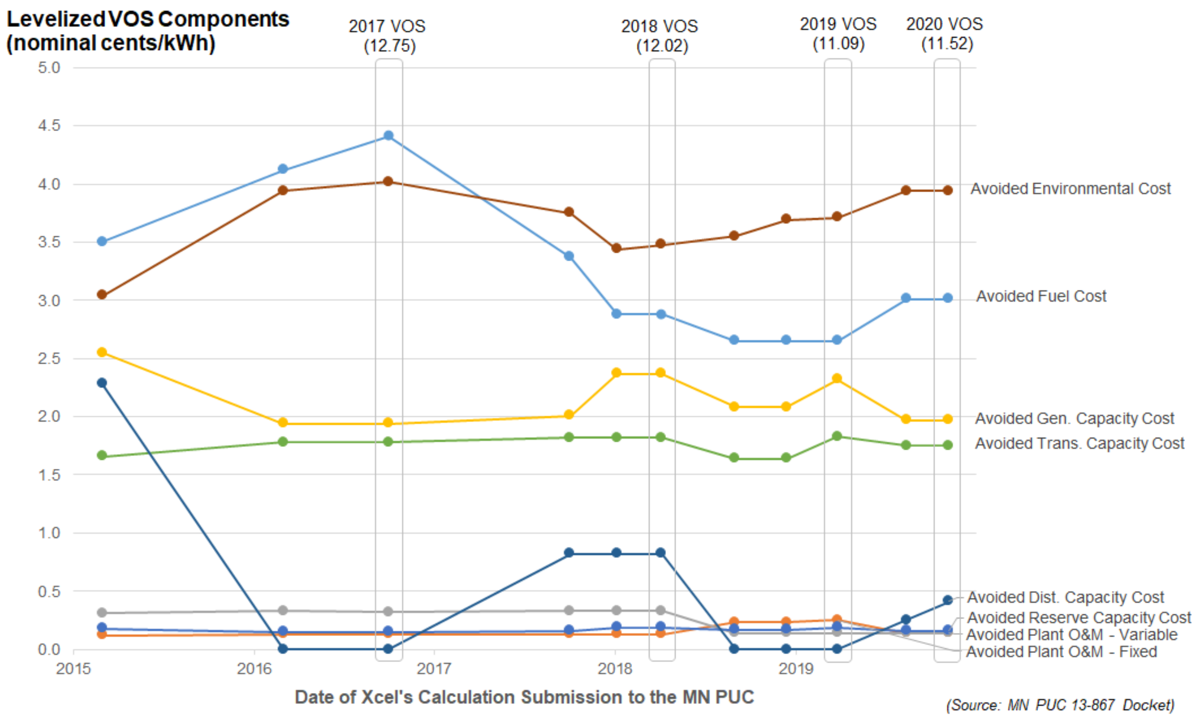

Figure 2. Xcel Energy's calculation of the value of solar, as submitted in Minnesota docket No. E002/M-13-867. The VOS was approved by the Minnesota Public Utilities Commission as an alternative tariff in 2017 - 2020 and has declined by 10% over this period.

As Figure 2 demonstrates, Xcel's 2017 VOS had a 25-year levelized value of 12.75 cents per kWh, 11% higher than the 2020 value. The avoided fuel cost component, which was over 40% higher in 2017 than 2020, was the primary driver for the change from 2017 - 2020.

Q. Please describe the costs and benefits that inform Minnesota's VOS tariff.

A. Minnesota's statute establishing the VOS framework provides guidance for the scope of costs and benefits that should inform compensation for distributed solar generation. Minnesota statute stipulates that the VOS is to represent "the value to the utility, its customers, and society for operating distributed solar photovoltaic resources." Minnesota statute further stipulates the values that must be included in the VOS methodology and others that could be optionally included on the basis of "known and measurable evidence of the cost or benefit[21]"

> The distributed solar value methodology established by the department must, at a minimum, account for the value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value. The department may, based on known and measurable evidence of the cost or benefit of solar operation to the utility, incorporate other values into the methodology, including credit for locally manufactured or assembled energy systems, systems installed at high-value locations on the distribution grid, or other factors.

In practice, the VOS methodology developed by the Minnesota Department of Commerce only included the minimum set of values required by statute but does include a provision to consider high-value locations on the distribution grid in future implementation.

Q. Please elaborate on the current monetary value and the methodology associated with each avoided cost component in the Minnesota VOS tariff.

A. As shown in Figure 2, Minnesota's VOS calculates the benefits of solar througheight avoided cost components. These components can be categorized as generation, transmission, distribution, and societal, as done in Table 3 on page 22. Each component, its value in the 2020 VOS for Xcel Energy, and a simple description of the way it is calculated is explained in Table 2.

[21] Minnesota Statute §216B.164, subd. 10(f).

Table 2: Value of Solar Value Categories Used in Minnesota with 2020 VOS Estimates for Xcel Energy

VOS Component		**2020 Value for Xcel Energy** (cents / kWh)	**Methodology and Additional Considerations** (summary of approved methodology[22])
Generation	Avoided Fuel Cost	3.01	"Avoided fuel costs are based on long-term, risk-free fuel supply contracts. This value implicitly includes both the avoided cost of fuel as well as the avoided cost of price volatility risk that is otherwise passed from the utility to customers through fuel price adjustments." Values are primarily derived from the New York Mercantile Exchange (NYMEX) natural gas futures contract market. However, natural gas futures are closely related to spot prices and contract markets are very thin more than a few years out.[23]
	Avoided Generation Capacity Cost	1.97	"Based on the installed capital cost of a peaking combustion turbine and the installed capital cost of a combined cycle gas turbine, interpolated based on heat rate."
	Avoided Reserve Capacity Cost	0.16	"Identical to the generation capacity cost calculation, except utility costs are multiplied by the reserve capacity margin."
	Avoided Plant O&M – Fixed	0.14	Utility O&M costs that are not dependent on the amount of energy generated
	Avoided Plant O&M – Variable	0.14	Utility O&M costs that are dependent on the amount of energy generated.
Transmission	Avoided Transmission Capacity Cost	1.75	"Based on the utility's 5-year average MISO OATT Schedule 9 charge"
Distribution	Avoided Distribution Capacity Cost	0.41	Can be calculated as a system-wide average value or location-specific value. Current practice has been to calculate this as a system-wide average, which until 2020, was calculated by dividing costs from capacity-related expenditures in FERC accounts 360, 361, 362, 365, 366, and 367 over the last 10 years by estimated future peak growth over the next 15 years. For the 2020 VOS, the methodology for this component was adjusted for one year and a stakeholder group was ordered to discuss methodological improvements to this component.[24]
Societal	Avoided Environmental Cost	3.94	Includes the environmental value of avoided carbon dioxide (CO_2), particulate matter below 2.5 microns (PM 2.5), carbon monoxide (CO), nitrogen oxides (NOx), lead (Pb), and sulfur dioxide (SO_2). Values for CO_2 are derived from a Federal Interagency Working Group on the social cost of carbon[25], and criteria air pollution externality values are based on scientific studies considered in Minnesota dockets E999/CI-93-583 and E999/CI-00-1636. In the 2020 VOS, CO_2 represented over 90% of this component and NOx represented an additional 8%.

Q. Has the VOS methodology itself evolved over time?

A. Other than minor changes to the practices of calculating the VOS within the options provided by the original methodology[26], there have been no revisions to the Department of Commerce's basic methodology as approved in 2014. While the methodology to calculate the VOS has not fundamentally changed, stakeholders have come to wide agreement that the avoided distribution cost component of the methodology is flawed. Based on a flawed representation of peak load growth, the methodology produced an unreasonable estimate of avoided distribution costs in the 2020 VOS for Xcel Energy. In December 2019, the Minnesota Public Utilities Commission approved a one-year exception for a change to this component of the VOS for 2020 and simultaneously ordered that Xcel, the Department of Commerce, and other stakeholders work to improve the VOS methodology. The stakeholder process to address the avoided distribution cost components in the VOS methodology is ongoing and set to resume in late June 2020.

I would also note that in 2019, the Minnesota PUC established an "adder" to the VOS that would provide an additional bill credit for residential-class community solar subscribers. In its November 2018 order establishing the adder, the Commission cited the legislative intent for the community solar program to "enable the creation, financing, and

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[22] For further detail see MN Department of Commerce VOS Methodology, available at: http://mn.gov/commerce-stat/pdfs/vos-methodology.pdf and Exhibit CEO-36 (GC-3).

[23] See also Chan, Gabriel. November 27, 2018. Comments on Xcel Energy's 2019 VOS Calculation and Proposed 2019 Vintage Year Bill Credit Tariff Sheets in Docket No. E002/M-13-867. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={009A5A67-0000-CC15-BF69-3E12D10B78DD}&documentTitle=201811-148058-01

[24] See Minnesota PUC. December 3, 2019. Order Approving Changes to Distributed Solar Value Methodology as Modified and Requiring Further Filings in Docket E999/M-13-867 and E999/M-14-65. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={30D2CC6E-0000-CA1D-A52B-274566AF32CF}&documentTitle=201912-157987-01

[25] See Interagency Working Group on the Social Cost of Greenhouse Gases. 2016 Revisions. https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf

[26] The VOS methodology that the Commission approved in 2014 provided several different options for calculating certain inputs to the VOS. For example, capacity factors for solar production can be based on simulated data or on actual data from a sufficient fleet of solar generators.

accessibility of solar gardens" and that "the costs of obtaining and serving residential subscribers are higher than other subscribers.[27]" The adder was set for two years at 1.5 cents per kWh for the 2019 and 2020 VOS vintage. No completed gardens are yet receiving the residential adder as of February 2020.

Q. Please summarize your perspective on the evolution of Minnesota's VOS tariff.

A. Minnesota's first-in-the-nation statewide methodology for a VOS tariff methodology applicable to public utilities is generally recognized as a successful framework for valuing distributed generation. In particular, stakeholders have commended the thorough, inclusive, and timely stakeholder process run by the Minnesota Department of Commerce to establish the methodology. Since the methodology was adopted in 2014, the state's largest utility has implemented the methodology in annual update cycles. And while the methodology has remained relatively stable, it has also been shown to be flexible enough to adapt to policy goals and incorporate methodological improvements. The VOS now covers 20 MW of operational distributed solar projects and over 200 MW of planned projects.

IV. VALUE OF SOLAR OFFERS AN EMINENTLY FEASIBLE TARIFF DESIGN FOR EQUITABLY TREATING DISTRIBUTED GENERATION CUSTOMERS

Q. What do you cover in this section of your testimony?

A. In this section of my testimony, I will explain why a Value of Solar tariff offers not only a feasible tariff design for Michigan customers, but also the most accurate method of establishing the "equitable cost of service" for distributed generation (DG) customers.

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[27] Minnesota Public Utility Commission. November 16, 2018. Order Adopting Adder and Setting Reporting Requirements in Docket No. E-002/M-13-867. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={B0DE1D67-0000-C217-96A6-3A771CB0C0B1}&documentTitle=201811-147853-01

Q. At a high level, please explain the advantages of a VOS.

A. A VOS tariff is a conceptually attractive approach to setting compensation for DG customers in contexts where some or all of the benefits of DG are unpriced by competitive markets.[28] Only a relatively small subset of the benefits of DG can be valued by competitive markets, particularly in the vertically integrated context of Consumers Energy.[29] Instead, non-market valuation of the many benefits of DG that can act as a "surrogate" for competitive pricing is required to compensate DG for the "real value provided by...[DG] installations to the electric system.[30]" A VOS methodology values all "real value" of DG, also referred to as its "social value," by aggregating any values that can be quantified in competitive markets with all other variables that are valued with non-market valuation methods. In this way, a VOS tariff values the full set of social benefits and allows the regulator to equitably consider DG impacts on all members of the public.

Q. Please elaborate how a VOS allows for the equitable consideration of all members of the public.

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[28] See for example, Kahn. 1988. *Economics of Regulation*. "The essence of regulation is the explicit replacement of competition with governmental orders as the principal institutional device for assuring good performance…Price regulation is the heart of public utility regulation." See also, Peskoe 2016. "Unjust, Unreasonable, and Unduly Discriminatory: Electric Utility Rates and the Campaign Against Rooftop Solar" *Texas Journal of Oil, Gas, and Energy Law*, 11(2) at footnote 80, citing case law of Citizens Action Coal. V. N. Ind. Pub. Serv. Co., 485 N.E.2d 610, 612 (Ind. 1985) which states that "the statutes which govern the regulation of utilities and which grant the PSC its authority and power provide a surrogate for competition and insure that the responsibilities of utility investors and consumers are commensurate with the responsibilities of investors and consumers in a competitive market."

[29] For example, one benefit of DG that accrues outside of a competitive market is avoiding spending on distribution infrastructure. This benefit accrues to ratepayers of Consumers Energy through reduced rates by having a lower rate base. However, rates for customers of Consumers Energy are set in regulatory processes and not by competitive markets. For electric delivery service, it would not be feasible to have robust competition of multiple suppliers of distribution services, due to what is referred to as a "natural monopoly." Therefore, the monetary value of such DG benefits requires non-market valuation strategies. A limited subset of DG benefits can be valued by competitive markets. For example, avoided fuel expenditures can be based on prices in competitive fuel markets—although challenges arise prospectively valuing future fuel prices, particularly because futures markets for many fuels are thin.

[30] Taylor, et al. 2015. *Value of Solar: Program Design and Implementation Considerations*. National Renewable Energy Laboratory, Technical Report NREL/TP-6A20-62361.

A. In the absence of competitive markets that internalize all externalities, consumers cannot express their preferences across multiple competing suppliers. Instead, administrative rules are required to take the place of market forces such that an incremental production decision is only made if the full social benefits of that production exceed its full costs. A VOS functions as such by setting prices equal to full social value (benefits less costs) and then leaves the decision to individual actors to adopt DG or not. A potential DG adopter will base their adoption decision on whether the VOS-based compensation for generation (at the social value level) exceeds their private costs of investing in DG. In this way, administrative oversight can ensure that pricing does not harm consumers as a result of the market power of producers or the lack of market power of those impacted by external costs. As a result, the tariff will reflect societal value but be based on equitable cost of service. But just as competitive markets require clear price signals and equal access to information, administratively determined prices based on non-market valuation of costs and benefits require transparency and a robust empirical basis. A VOS tariff that equitably compensates customers for the ***social value*** of their DG systems would help ensure that DG pricing does not harm Michigan citizens (including, but not limited to, Consumers Energy customers).

Q. What do you mean by "social value"?

A. Social value refers to the sum total of all costs and benefits of a decision to all actors, including those party to the decision and those external to the decision. In the case of DG, social value includes all costs and benefits to the customer installing DG, to all other customers, to the utility, and to all members of the public—including future generations. Cost benefit analysis is an analytic tool use to quantify social value. In a review of past applications of cost benefit analysis to distributed solar generation in 15 states prepared for the U.S. Department of Energy, the consulting firm ICF found that different states have taken different approaches to including specific value categories[31], see Attachment CEO-38 (GC-5). The different value categories; whether a value can be a cost, benefit, or both; and the number of studies (out of 15) that included the value are shown in the Table 3 below. The table notes whether distributed solar generation is considered to provide benefits or costs in each of the identified areas, though the magnitude of the benefits or costs are not provided.

Table 3: Value of Solar Value Categories Used in State Cost Benefit Analyses[32]

Value Category		Benefit (+) or Cost (-)	Number of Studies Addressing this Category (out of 15)
Utility System Impacts			
Generation	Avoided Energy Generation	+	15
	Avoided Generation Capacity	+	15
	Avoided Environmental Compliance	+	10
	Fuel Hedging	+	9
	Market Price Response	+	6
	Ancillary Services	+/-	8
Transmission	Avoided Transmission Capacity	+	15
	Avoided Line Losses	+	11
Distribution	Avoided Distribution Capacity	+	14
	Avoided Resiliency & Reliability	+	5
	Distribution O&M	+/-	4
	Distribution Voltage and Power Quality	+/-	6
Cost	Integration Costs	-	13
	Lost Utility Revenues	-	7
	Program and Administrative Costs	-	7
Societal Impacts			
External Value to Society	Avoided Cost of Carbon	+	8
	Other Avoided Environmental Costs	+	9
	Local Economic Benefit	+	3

[31] ICF. May 2018. Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar. https://www.icf.com/-/media/files/icf/reports/2019/icf-nem-meta-analysis_formatted-final_revised-1-17-193.pdf

[32] Adopted from ICF. May 2018. Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar. https://www.icf.com/-/media/files/icf/reports/2019/icf-nem-meta-analysis_formatted-final_revised-1-17-193.pdf. See also Environment America. 2019. The True Value of Solar: Measuring the Benefits of Rooftop Solar

Q. Why is VOS a potentially attractive approach to DG compensation in Michigan?

A. A Value of Solar framework best approaches compensating DG customers based on their "fair and equitable use of the grid." Michigan statute Sec. 6a(14), Sec. 11(1) of Act 341 calls for DG customers to be assessed for their "fair and equitable use of the grid." That section provides that:

> Except as otherwise provided in this subsection, the commission shall ensure the establishment of electric rates equal to the cost of providing service to each customer class. In establishing cost of service rates, the commission shall ensure that each class, or sub-class, is assessed for its fair and equitable use of the electric grid.

Michigan Public Service Commission staff have emphasized that an inflow-outflow approach to compensating distributed solar should meet several criteria. In its 2018 staff study, MPSC staff described key principles,[33] "the separation of power inflows from power outflows readily allows for rate designs that incorporate traditional cost of service study (COSS) methods, thus ensuring that DG customers are assessed for their fair and equitable use of the grid. It also provides an independent framework for equitably compensating DG customers for excess power injected into the grid."

Equitable compensation for power injected into the grid should be based on the social value of injected power. Otherwise, if compensation is below social value, DG customers will be unfairly under-compensated for the social benefits of their injected power, creating a net cross-subsidy from DG customers to society. Further, such under-compensation will also fail to realize all opportunities for DG generation that creates

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Power.
https://environmentamerica.org/sites/environment/files/resources/AME%20Rooftop%20Solar%20Jul19%20web.pdf

[33] Report of the MPSC Staff Study to develop a Cost of Service-Based Distributed Generation Program Tariff." February 21, 2018.
https://www.michigan.gov/documents/mpsc/MPSC_Staff_DG_Report_with_Appendices_614779_7.pdf

greater benefits to society than costs. If compensation for injected power of DG is above social value, the reverse would be true and there would be a net cross-subsidy from society to DG customers. Valuing injected power at exactly the social value, as measured by the VOS, would eliminate all net cross-subsidies.

As framed by the Minnesota Department of Commerce, [34] "VOS eliminates cross-subsidization concerns with net metering" and the "VOS is fair to the utility and non-solar customers, provides fair compensation to the solar customer, decouples compensation from incentives, aligns public policy goals (decouples compensation from consumption), [and is] intuitively and analytically sound and administratively simple."

Q. Please elaborate on the Minnesota Department of Commerce's conclusion that a VOS tariff eliminates cross-subsidization concerns with net metering.

A. Minnesota statute does not explicitly establish a policy goal for the VOS to reduce cross-subsidies associated with net energy metering; however, eliminating any net metering cross-subsidies was generally seen by stakeholders as a benefit of the VOS.[35] In its role supporting the Minnesota Department of Commerce in its development of the VOS, Clean Power Research articulated that a properly designed VOS creates no new net cross subsidization between solar and non-solar customers or between customers of different rate classes. According to Clean Power Research, compensating distributed solar with the

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[34] Minnesota Department of Commerce. March 4, 2014 before the Minnesota Public Utilities Commission. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={007DDF1B-C60D-4D37-8066-275A67968CCD}&documentTitle=20143-97059-01

[35] See Minn. Pub. Util. Comm'n, Docket No. E999/M-14-65. Joint Reply Comments of Environmental Law and Policy Center (ELPC), Fresh Energy (FE), Interstate Renewable Energy Council, Inc. (IREC), Institute for Local Self-Reliance (ILSR), Izaak Walton League of America (IWLA), SunEdison, LLC (SE), and the Vote Solar Initiative(VSI), (February 20, 2014), available at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={05921A68-4238-4D98-AD26-76A3FD22C50F}&documentTitle=20142-96684-01

VOS creates no impact on the long-run cost of service, as, for example, 'the savings gained from capacity costs is directly offset by increased cost of VOS credits"[36]. Further, for the benefits that do not directly involve other changes to the utility balance sheet (such as avoided environmental costs), all customers pay for the new expense of creating such benefits through the pass-through of recovered VOS bill credits to all consumers, and ostensibly, all consumers enjoy these benefits (although some environmental benefits are "given for free" to individuals outside of a utility's current ratepayers, such as future generation whose exposure to climate change can be reduced from DG's avoidance of greenhouse gas emissions).

Q. Please elaborate on how a VOS tariff could create no new net cross-subsidies.

A. Cross-subsidies are a form of externality and are a regular feature of current utility practices. Cross-subsidization arises from traditional rate design that establishes volumetric prices for many fixed costs and from the many unpriced or otherwise unregulated (or underpriced or under-regulated) externalities associated with long-lived capital investments and fossil-fuel extraction and combustion[37]. By establishing a rate for compensating solar that includes all private and social values, the Commission can achieve an economically efficient outcome that reflects cost of service with no net cross subsidies because all external costs and benefits enter into the decision function of the DG investor.

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[36] Clean Power Research. Value of Solar Tariff Methodology, Proposed Approach. (Oct. 1, 2013). Available at: https://www.slideshare.net/farrell-ilsr/mn-vosworkshop-130916v3-26949719

[37] National Research Council. 2010. *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use*. https://download.nap.edu/cart/download.cgi?record_id=12794

Stakeholders in Minnesota reinforced the notion that a VOS tariff (that includes all values to the utility, its customers, and society) can achieve economically efficient price signals to investors. The Department of Commerce stated:[38] "The VOS is not an incentive for distributed PV, nor is it intended to eliminate or prevent current or future incentive programs." Xcel Energy reinforced this view,[39] stating that "the VOS rate is not itself an incentive...To the extent that an incentive is needed to bring the VOS to the retail rate or additional incentives are needed to spur the market, these incentives should be clearly labeled and separate from the base VOS components."

Q. What is the distinction between 'no net cross-subsidies' and 'no cross-subsidies' and how does this relate to economic efficiency?

A. The existing allocation of costs in any real-world electricity system involves significant cross-subsidization, across and within rate classes. Therefore, nearly any new adjustment to the system, such as a new resource deployment, will almost certainly create new cross-subsidies. The objective of a VOS tariff that pays for new DG outflow generation at its social value is to create no new *net* cross-subsidies. This condition is consistent with the criteria of economic efficiency that maximizes social welfare. Administratively setting prices equal to social value ensures that all DG that creates more benefits than costs will be privately beneficial to potential DG investors, thereby aligning the private interests of potential DG investors with maximizing social welfare. However, while an outcome that

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[38] Minnesota Department of Commerce. January 31, 2014. Filing of the Minnesota Department of Commerce in Docket No. E999/M-14-65. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={90E29DF3-90F1-4FD1-BA3A-30CA4BDC54F0}&documentTitle=20141-96033-01

[39] Xcel Energy. February 13, 2014. Comments: Value of Solar Methodology in Docket No. E999/M-14-65. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7b5D1AFDC4-B46B-4A5D-841F-852F33F87F38%7d&documentTitle=20142-96427-01

maximizes social welfare creates no net cross-subsidy, it may create cross-subsidies across actors relative to the status quo. This is because an economically efficient outcome works to "undo" the existing cross-subsidization within the system by reallocating benefits to those that pay the costs of a benefit-creating investment. This is true even where the new regime reflects equitable cost of service.

Said another way, the existing system is imperfect in allocating costs in proportion to benefits (e.g. volumetric rates provide equal benefit when costs vary), which creates a cross-subsidy (e.g. consumers with greater on-peak demand impose greater costs but can derive equal benefits). Paying for DG outflow in direct proportion to social value aligns costs with benefits by rewarding all DG outflow that creates benefits that are greater than costs. However, due to existing structures of rate design and features of the utility business model, such a cost allocation can shift costs and benefits between actors while still creating overall net system benefits. As such, a VOS can be implemented in a way that serves the public interest by increasing overall welfare while at the same time leaving some actors worse off (e.g. utilities that invested in distribution infrastructure that is now underutilized may see a net cost relative to the status quo due to deferred investment, but overall, the public could see an even greater benefit through reduced rates and environmental benefits).

Q. How does VOS square with the Bonbright principles of rate design?

A. The Rocky Mountain Institute offers a re-interpretation of James Bonbright's seminal principles of rate design to account for DERs[40]. This reinterpretation is consistent with

[40] Glick, Devi and Matt Lehrman. 2014. "Rate Design for the Distribution Edge: Electricity Pricing for a Distributed Resource Future." https://rmi.org/insight/rate-design-for-the-distribution-edge-electricity-pricing-for-a-distributed-resource-future/

the analysis provided in Witness Karl Rabago's testimony. Notable for this discussion is the reinterpretation of the Bonbright principle, "Rates should fairly apportion the utility's cost of service among consumers and should not unduly discriminate against any customer or group of customers." RMI's "21st century interpretation" accounting for DERs is, "Rate design should be informed by a more complete understanding of the impacts (both positive and negative) of DERs on the cost of service. This will allow rates to become more sophisticated while avoiding undue discrimination." In further explanation, this report continues, "Cross-subsidies have always been present in rates. The important thing is to ensure that any subsidies within and across customer classes achieve the policy goals they were designed to achieve without creating undue burden on individuals or groups of customers [...] Cross-subsidies that are exacerbated as DER penetration grows can be managed through more granular rate design."

The Commission can realize this notion through a well-designed VOS tariff that maximizes the production of DG that creates more social benefits than private costs. A VOS framework does not preclude or eliminate other rate design mechanisms necessary to achieve additional policy goals. For instance, additional policy goals to allocate benefits fairly could be negotiated separately, such as by considering how to allocate the burden of cost recovery for export credits across customers and classes. This allocation problem could be particularly important to consider as not all rate classes contribute equally to fixed costs or are allocated a proportional burden of paying for fixed costs, and therefore not all are not equal beneficiaries in avoiding future fixed costs due to DG deployment.

Q. Do analytic challenges associated with estimating specific private or social benefits of DG imply that the Commission should explicitly or implicitly assume such benefits are zero?

A. No. The set of private and social values that DG creates are difficult but not impossible to quantify in a transparent, credible, and reasonably accurate manner. In each component of the VOS, there are elements that make estimation difficult. Avoided costs are uncertain as many benefits are in the future and have many exogenous contingencies. However, despite this, the existence of estimation challenges does *not* suggest any principled basis for assuming that any uncertain avoided cost of DG is certainly zero. While some classes of benefits that DG could provide are difficult to quantify, the notion that such benefits should be excluded from compensation creates a bias of omission and implicitly values the entire class of benefits at zero. This bias of omission appears to be reflected in the direct testimony of Hubert W. Miller III on behalf of the Company, "although some advocates have argued that DG customers benefit the grid, I have yet to find any compelling research supporting this claim." I would point the Commission to the testimony of witness Rabago that details multiple studies of DG's social value that would strongly suggest that even though some benefits may be difficult to quantify, assuming these benefits are zero would create a substantial bias and therefore run contrary to the statutory requirement of equitable treatment for DG customers. A methodology for equitably valuing DG outflow should treat all non-zero costs and benefits of DG, and where estimation is difficult, should adopt estimation approaches that are transparent and as accurate as feasible, recognizing that there may be a tradeoff between transparency and accuracy.

Further, the difficulty of estimating specific avoided costs in a carefully conducted and transparent VOS process could actually itself provide meaningful new data and understanding that can improve future VOS estimation and rulemaking. Once analytic resources are brought to bear to estimate specific benefit streams, data and understanding will improve and future estimates will be made more precise as a result.

Q. How has Minnesota's experience demonstrated the eminent feasibility of adopting a VOS tariff despite known imperfections in estimating particular avoided costs?

As described above, Minnesota's statute establishing the VOS specified several benefit categories required to be included in the Department of Commerce's VOS methodology as well as an avenue to incorporate additional values. In practice, the VOS methodology developed by the Minnesota Department of Commerce has only included the minimum set of values required by statute.

During the stakeholder engagement process leading up to the methodology's development, several stakeholder groups suggested that other benefit streams would satisfy the statute's requirement of having "known and measurable evidence." For example, in joint comments filed by the Environmental Law and Policy Center[41], stakeholders suggested that the avoided cost of private volatility risk was a known and measurable benefit of solar to a utility's customers. As evidence for whether this benefit was known, stakeholders referenced acknowledgment by Xcel Energy that solar provides such benefits. As evidence that this benefit was measurable, commenters pointed to three

[41] See Environmental Law and Policy Center (ELPC), Fresh Energy (FE), Interstate Renewable Energy Council, Inc. (IREC), Institute for Local Self-Reliance (ILSR), Izaak Walton League of America (IWLA), SunEdison, LLC (SE), and the Vote Solar Initiative(VSI). February 20, 2014. Joint Reply Comments in Docket No. E999/M-14-65. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={05921A68-4238-4D98-AD26-76A3FD22C50F}&documentTitle=20142-96684-01

different quantification options for this benefit that were discussed during stakeholder meetings. Ultimately, the PUC did not adopt a specific additional quantified value for reduced price volatility but instead modified the formulation of avoided fuel costs to respond to the issue raised[42].

One important feature of the Minnesota VOS is the adoption of several "transparency elements." These elements are comprised of two publicly available tables that provide a list of key input assumptions and calculations and, as described in the approved methodology, are designed to "facilitate understanding among stakeholders and regulators." More recently, the PUC has required Xcel Energy to provide even greater clarity in how input values affect changes to the VOS over time.

The PUC established a VOS despite certain limitations in quantifying each avoided cost component, and over time, stakeholders have pushed the PUC to quantify additional components and to improve the accuracy and transparency of the estimation of included components. The public comment period in each annual cycle of Xcel Energy's implementation of the VOS methodology has created a substantial public record for considering additional methodological and process improvements as more data is collected and more experience is gained.

Q. How might Consumers Energy assess the environmental value of DG?

A. Environmental economists have developed a robust set of methodologies for valuing environmental benefits, and environmental valuation is a regular part of state and federal rulemaking. Central to valuing environmental benefits is comprehensively assessing all

[42] MN PUC. 2014. Order Approving Distributed Solar Value Methodology in Docket E999/M-14-65. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={FC0357B5-FBE2-4E99-9E3B-5CCFCF48F822}&documentTitle=20144-97879-01

environmental effects in an integrated fashion without double counting, and where possible, deriving economic values from the revealed preferences of free actors. The U.S. Environmental Protection Agency provides guidelines for preparing economic analyses involving environmental benefits, including greenhouse gases and criteria pollutants[43]. For greenhouse gases in particular, the Federal Interagency Working Group on the Social Cost of Greenhouse Gases produced monetary values for the benefits of reduced greenhouse gas emissions[44] that could be directly applied in Michigan, as was done in Minnesota's Value of Solar.

Q. Why is it important for Consumers Energy to evaluate the environmental value of DG?

A. As I have explained, by incorporating not just the system values to ratepayers and utilities that DG can provide but also incorporating all environmental values, a VOS tariff helps reduce existing cross-subsidies in the energy system that exist due to unpriced external costs. In other words, due to a lack of price signals to reduce pollution to socially optimal levels (i.e. closing the gap between the marginal cost of mitigating pollution and the marginal benefits of reducing pollution), emitters of pollution are receiving a *defacto* subsidy. Also, as witness Rabago explains, it is essential that the Commission understand the environmental impacts of DG projects in future resource planning. Under the Michigan Environmental Protection Act, the Commission is obligated to determine

[43] Environmental Protection Agency. 2010. *Guidelines for Preparing Economic Analyses*. https://www.epa.gov/environmental-economics/guidelines-preparing-economic-analyses
[44] Interagency Working Group on the Social Cost of Greenhouse Gases. 2016 Revisions. https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf

whether approval of utility actions would impair the environment and whether there is a feasible and prudent alternative.[45]

For example, if a resident hundreds of miles from a power plant develops asthma from air pollution causally linked to a power plant[46], and if the impact of that pollution leads the resident to incur private costs (e.g. missed employment, health care expenses), the utility receives a *defacto* subsidy because a social cost associated with its business activities are not accounted for in its production decision-making process; it is creating a harm that it is not paying for. A VOS tariff that incorporates environmental benefits recognizes that DG can cause otherwise unpriced (or underpriced) emissions to decrease; and therefore, all social benefits should be accurately priced and included in the tariff. As a result, less additional cross-subsidies are created by undervaluing societal benefits. This line of thinking reveals that a socially optimal VOS that incorporates all social costs and benefits may create new cost and benefit shifts (relative to the status quo) in order to achieve the goal of price signals aligned with achieving outcomes in the public interest.[47] One manifestation of this could be distributed solar installations that create benefits for the customer who installs the system (because the VOS exceeds the levelized project

[45] *See, e.g.*, Case No. U-20471, MPSC Order, at 42 (Feb. 20, 2020).

[46] See for example EPA. 2016. Air Quality Modeling Technical Support Document for the Final Cross State Air Pollution Rule Update at page E-5 which shows modeled contributions of emissions from Allegen County, Michigan to downstream ozone pollution levels on days where downstream pollution levels exceeded air quality standards. Impacts from this source were modelled to affect a range across the continental United States. https://www.epa.gov/sites/production/files/2017-05/documents/aq_modeling_tsd_final_csapr_update.pdf

[47] This notion of public interest is grounded in the widely adopted notion of "Kaldor-Hicks efficiency," which posits that an efficient outcome is one that produces greater total net benefits than costs. In principle, a policy change that is Kaldor-Hicks efficient creates greater net social benefits which subsequent policy could complement with socially or politically desirable allocations of costs and benefits to specific actors. (see, e.g. https://www.oxfordreference.com/view/10.1093/oi/authority.20110803100028833). In the context of the VOS, this might suggest exploring opportunities to align utility incentives with providing socially desirable outcomes that would otherwise conflict with existing utility incentives, such as the development of "performance based regulation."

costs), benefits for non-installing ratepayers (because the project avoids environmental harms and avoids costs in the future because of a smaller rate base), but creates new costs for the utility (because of a smaller rate base on which to earn returns). In this example, if the net benefits to the installing customer and the non-installing customers outweigh the net costs to the utility, such an outcome would still be in the public interest, as classically defined in economics as a net increase in producer plus consumer surplus.

Q. Should Consumers Energy include the cost of complying with environmental regulations in addition to the environmental value of DG?

A. Yes. Societal benefits do not equate empirically to the compliance costs of meeting environmental regulations, given that reducing key pollutants from the power sector—as currently regulated—would create significant benefits.[48] In principle, if distributed solar avoids compliance costs associated with environmental regulations (e.g. by providing renewable energy credits or solar energy credits to a utility), those avoided costs should also be included in a VOS in addition to avoided societal environmental costs without concern for double counting. In other words, DG that reduces pollution avoids the utility's environmental compliance costs and also avoids additional environmental damages.

In case U-20471 (the DTE integrated resource plan), the Commission considered environmental harms in addition to compliance costs under the Michigan Environmental Protection Act . In this case, the Commission ordered on February 20, 2020 that Section 1705(1) of MEPA, MCL 324.1705(1) applies to utility regulation. Therefore, it would be

[48] See for example, Di. et al. (2017) in the *New England Journal of Medicine* which found "there was significant evidence of adverse effects related to exposure to PM2.5 and ozone at concentrations below current national standards. This effect was most pronounced among self-identified racial minorities and people with low income." https://www.nejm.org/doi/full/10.1056/nejmoa1702747

consistent for the Commission to determine under MEPA: (1) whether the [DG tariff modifications] would impair the environment; (2) whether there was a feasible and prudent alternative to the impairment; and, (3) whether the impairment is consistent with the promotion of the public health, safety, and welfare in light of the state's paramount concern for the protection of its natural resources from pollution, impairment or destruction. This is consistent with the Commission's adoption in the MIRPP, p. 12, of MEPA as one of the state environmental laws that may apply to an IRP proceeding.[49]

V. UNDERTAKING A VALUE OF SOLAR STUDY AS THE BASIS FOR COMPENSATING CONSUMERS ENERGY'S DG CUSTOMERS WOULD SERVE THE PUBLIC INTEREST AND BE CONSISTENT WITH THE ENABLING STATUTE

Q. What do you cover in this section of your testimony?

A. In this section of my testimony, I explain why the Commission should direct Staff to lead stakeholders in a developing a comprehensive framework for a VOS analysis and direct Consumers Energy to evaluate the costs and benefits of DG deployment and operations in its service territory using the framework developed by Staff.

Q. How can a VOS approach balance the interests of utilities, ratepayers, and DG customers?

Balancing the interests of different stakeholders that are affected by a DG tariff is a balancing act. Specifically, the analytic task of establishing a VOS requires compromises that balance the competing goals of accuracy (to avoid any incidental cross-subsidization between the utility, ratepayers, and DG customers) and practicality (to enable timely implementation, transparency, and collaborative feedback). In reviewing possible VOS

[49] See Michigan Integrated Resoure Planning Parameters, November 21, 2017, at p. 12; Case No. U-20471, MPSC Order, at 42 (Feb. 20, 2020).

approaches, the National Renewable Energy Laboratory (NREL) illustrated potential tradeoffs with a schematic (replicated in Figure 3).[50].

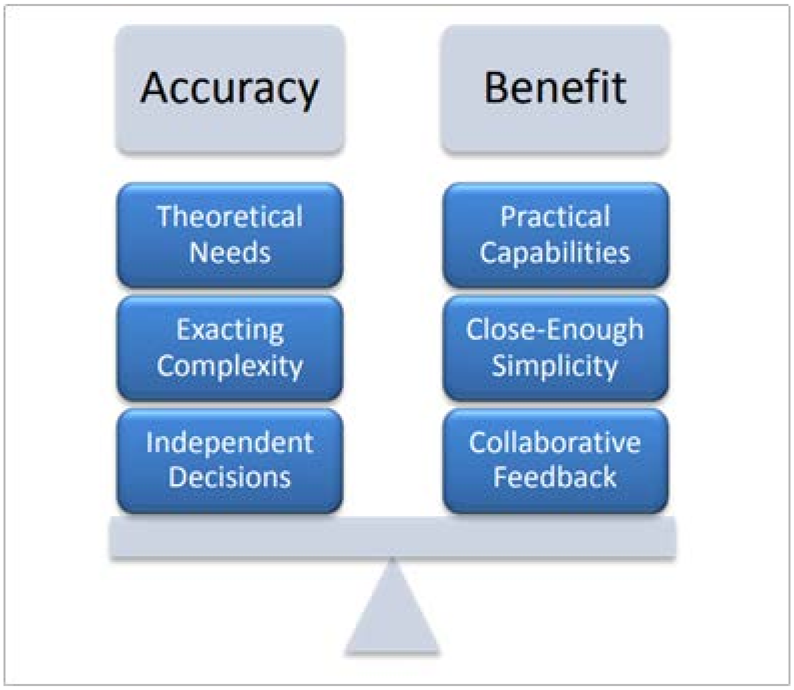

Figure 3. Schematic Representation of the Value of Solar Balancing Act (Taylor, et al, 2015)[51]

This NREL report illustrated this tension in the context of incorporating locational differentiation into the VOS as an example:

> Location-specific VOS rates could be designed to represent a greater or lesser VOS across an individual utility's service territory, which would manifest in utility cost savings at the distribution or transmission level. While it is more accurate to reflect each individual solar system's value to the utility system, the question remains whether this level of accuracy yields sufficient benefit or practicality. When put into practice, the VOS rate could vary across hundreds of individual distribution circuits or in several larger geographic areas. But this accuracy needs to be balanced against the simplicity of a single VOS rate across an entire utility's territory. Limiting the number of different VOS rates will likely facilitate calculations, rate updates, customer marketing and communications with customers, the industry and other stakeholders. Just as utilities set electricity rates based on an average customer consumption profile per

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[50] Taylor, Mike, et al. 2015. Value of Solar: Program Design and Implementation Considerations. https://www.nrel.gov/docs/fy15osti/62361.pdf and Exhibit CEO-37 (GC-4).

[51] https://www.nrel.gov/docs/fy15osti/62361.pdf

> customer class, a single VOS rate, representing the average value that solar provides across the system may be easier to set and implement than multiple rates.

The notion of designing cost of service rates that assess "fair and equitable use of the grid" is fundamentally a challenge of equitable division of costs, which is discussed at length in a recent report from the Regulatory Assistance Project (RAP)[52]. The RAP report emphasizes the point that cost allocation balances stakeholder interests and provides new insight into the existing structure of costs:

> Cost allocation may be more of an art than a science, since fairness and equity are often in the eye of the beholder…however, the techniques used in cost allocation have been designed to mediate these disputes between competing sets of interests. Similarly, the data and analysis produced for the cost allocation process can also provide meaningful information to assist in rate design, such as the seasons and hours when costs are highest and lowest, categorized by system component as well as by customer class.

Q. Can you give the Commission more context on that point?

Writing on electric ratemaking in 1961, James Bonbright stated, "utility rates, like other prices, are designed to perform multiple functions as instruments of economic control. To a high degree, these functions can be performed in harmony; necessarily so, indeed, since they are partly complementary. But the harmony is far from complete, for the most efficient performance of any one function would require the acceptance of a system of rates not also best designed to perform any of the others. In consequence, one of the most frustrating problems of rate theory and of practical rate making is that of suggesting and applying principles of workable compromise."[53]

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[52] Lazar, Jim, Paul Chernick, and William Marcus. 2020. Electric Cost Allocation for a New Era. Regulatory Assistance Project. https://www.raponline.org/wp-content/uploads/2020/01/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf

[53] Bonbright, James. 1961. *Principles of Public Utility Rates*. Columbia University Press. Pg. 386.

Researchers at the U.S. National Labs described the way in which a VOS tariff can mediate the competing interests of electricity sector stakeholders[54], "A multitude of objectives and stakeholder perspectives are prioritized and harmonized during a DGPV [distributed generation photovoltaic] tariff design process...ensuring that stakeholders understand the full range of issues considered will help to enable focused and productive engagement"

The balancing act that the VOS methodology must play between accuracy and practicality is compounded by the irreducible uncertainty in many of the fundamental drivers of the system-value that DG provides (e.g. long-run avoided costs of volatile natural gas purchases). In presenting its VOS methodology, the Minnesota Department of Commerce noted[55], "the VOS methodology requires broader assessment than current resource planning and thus requires new analytical approaches." However, today's uncertainty and data constraints are not immutable and are likely to reduce over time, especially as we learn more about our common electric system.

With these sentiments in mind, it is important that the first implementation of a VOS tariff is not viewed as the end point of setting policy for distributed energy resource integration to serve the public interest. Instead, establishing a VOS for the first time should be seen as a midway point of a process to integrate new technologies that create varying degrees of private and social benefits. With this perspective, it becomes clearer that establishing a VOS tariff should be part of an adaptive management process to

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[54] Zinaman, Owen and Naim Dargouth. 2015. "A Valuation-Based Framework for Considering Distributed Generation Photovoltaic Tariff Design." https://www.nrel.gov/docs/fy15osti/63555.pdf

[55] Minnesota Department of Commerce. March 4, 2014 before the Minnesota Public Utilities Commission. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={007DDF1B-C60D-4D37-8066-275A67968CCD}&documentTitle=20143-97059-01

uncover new data, develop new working relationships, grow collective understanding of shared infrastructure systems, and collaborate across sectors to serve the public interest.

Q. What do you mean by "adaptive management"?

A. Adaptive management is an approach to governing complex systems that combines management with monitoring, with the goal to iteratively improve decision-making and knowledge about the system over time. The U.S. National Research Council defines adaptive management as[56]:

> Adaptive management [is a decision process that] promotes flexible decision making that can be adjusted in the face of uncertainties as outcomes from management actions and other events become better understood. Careful monitoring of these outcomes both advances scientific understanding and helps adjust policies or operations as part of an iterative learning process… It is not a 'trial and error' process, but rather emphasizes learning while doing. Adaptive management does not represent an end in itself, but rather a means to more effective decisions and enhanced benefits. Its true measure is in how well it helps meet environmental, social, and economic goals, increases scientific knowledge, and reduces tensions among stakeholders.

Adaptive management provides a helpful framework for decision making with uncertainty and the potential for learning over time. While adaptive management has been widely applied to manage natural resource systems[57], adaptive management is also being adapted to the regulatory context and administrative law[58].

Q. How should VOS be implemented such that it anticipates the process improving over time?

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[56] National Research Council. 2004. *Adaptive Management for Water Resources Planning*.

[57] See for example, USGS https://www.usgs.gov/centers/pwrc/science/adaptive-management?qt-science_center_objects=0#qt-science_center_objects and U.S. Department of the Interior Adaptive Management Working Group. 2009. *Adaptive Management: The U.S. Department of the Interior Technical Guide*. https://edit.doi.gov/sites/doi.gov/files/migrated/ppa/upload/TechGuide.pdf

[58] See for example, Ruhl, J.B. 2005. "Regulation by Adaptive Management—Is it Possible?" *Minnesota Journal of Law, Science, and Technology* 7(1) and Craig, Robin Kundis and J.B. Ruhl. 2014. "Designing Administrative Law for Adaptive Management." *Vanderbilt Law Review* 67(1).

A. Developing a VOS should be iterative, and it does not need to be perfect the first time around. Minnesota's experience leading an inclusive, robust, and efficient stakeholder process can be instructional in incorporating early feedback and cultivating buy-in. In the Department of Commerce's stakeholder working groups in 2013-2014, Clean Power Research introduced several objectives for the VOS methodology[59] that the Department endorsed[60]:

- Accurately account for all relevant value streams
- Simplify input data set, where possible
- Simplify methodology, where warranted
- Easy to modify, if necessary, in future years
- Provide transparency

Further, Minnesota's VOS methodology includes several different methodological options for specific components that have allowed for some degree of refinement without requiring re-opening the methodology for regulatory review. An example of this is the flexibility the 2014 methodology allowed for incorporating locationally differentiated values of avoided distribution costs. While the Minnesota methodology allows for an aggregate value for this component, it also leaves space for the implementing utility to propose an approach to differentiate by location.

Q. Are there other principles that the Commission should consider as it implements an increasingly refined DG compensation framework?

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[59] https://www.slideshare.net/farrell-ilsr/mn-vosworkshop-130916v3-26949719

[60] Minnesota Department of Commerce. January 31, 2014. Filing of the Minnesota Department of Commerce in Docket No. E999/M-14-65. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={90E29DF3-90F1-4FD1-BA3A-30CA4BDC54F0}&documentTitle=20141-96033-01

A. Looking to the future and beyond Minnesota, RMI[61] identifies three "continuums" that offer a path forward for increasing the sophistication of DER tariffs. These continuums are the "attribute continuum—the unbundling of rates to specifically price energy, ancillary services, etc.," the "temporal continuum—moving from volumetric block rates towards highly time-differentiated prices that vary in response to marginal prices or other market signals," and the "locational continuum—delivering price signals that more accurately compensate for unique, site-specific value."

The MPSC has already recognized the potential for a DG tariff to facilitate adaptive management:

> The Inflow/Outflow tariff is an adaptable billing mechanism that allows for equitable COS and is enabled by improved data collection. As the DG program evolves and more data becomes available, the Commission will better be able to assess the cost and benefit impacts and conduct rate design consistent with COS principles.

Q. In your assessment, how has the Value of Solar aligned the interests of utilities, ratepayers, and third parties in Minnesota?

A. Compensation for DG provides signals to potential DG adopters who face an investment climate fundamentally different from that of monopoly utilities. Therefore, it can be expected that interests will not align across all stakeholders, making equitable treatment between all stakeholders a key priority. As demonstrated by the breadth of stakeholder participation in Minnesota's process to establish a VOS methodology, the VOS impacts the interests of utilities, third-party developers, environmental nonprofits, ratepayer advocates, the broader public, and neutral third-party technical experts. To make

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[61] Glick, Devi and Matt Lehrman. 2014. "Rate Design for the Distribution Edge: Electricity Pricing for a Distributed Resource Future." https://rmi.org/insight/rate-design-for-the-distribution-edge-electricity-pricing-for-a-distributed-resource-future/

meaningful progress working across a wide range of interests, it was important to first build buy-in for the importance of the VOS as a framework that could provide a neutral deliberation platform.

Prior to the finalization of the VOS methodology, there was wide agreement that the VOS represented the best conceptual approach for enabling higher DER penetration. During the comment period on the draft methodology of the VOS in February 2014, Xcel Energy, the state's largest utility (and as of June 2020, the only utility implementing the VOS methodology), expressed its support for the approach of a VOS tariff[62]:

> As noted in the proposed methodology, the primary advantage of a VOS tariff compared to net metering is that, if properly designed, the VOS tariff will level the playing field for distributed solar, such that the utility and customers are indifferent from a cost perspective as to whether their energy comes from distributed solar or from the broader energy mix. This advantage is realized when the rate paid under the VOS tariff accurately reflects the true avoided costs and tangible benefits of distributed solar on a particular utility system. In other words, when the amount customers are paying for distributed solar equals the costs that are avoided, there is no impact on rates and no inequity between solar and non-solar customers. In this scenario, solar customers share in the cost of maintaining the grid and are paid a fair value for their contributions. In our view, this is distributed solar "done right." By basing solar rates on facts and objective analysis, we can transition to higher levels of distributed resources while maintaining a reliable grid, offering affordable rates, and avoiding cost-shifts between customers.

Similarly, the Minnesota Solar Energy Industries Association (MnSEIA), the trade association for solar developers in Minnesota, expressed its support for a VOS approach:

> MnSEIA supports the Value of Solar Tariff (VOST) methodology proposed by the Division of Energy Resources (DER) pursuant to Minn. Stat. §216B.164, subd.10. All of the proposed elements have been

[62] Xcel Energy. February 13, 2014. Comments: Value of Solar Methodology in Docket No. E999/M-14-65. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={5D1AFDC4-B46B-4A5D-841F-852F33F87F38}&documentTitle=20142-96427-01

discussed from several angles thru [sp] the stakeholder process and the proposed VOST captures much of the multiple layers of stakeholder input.

Q. How can a Value of Solar approach to compensating DG enable more robust and transparent decision-making processes that balance the interests of multiple stakeholders?

A. Many of the benefits of DG are analytically difficult to quantify. DG benefits, as framed in a VOS, are avoided costs. And avoided costs cannot be directly measured—they are costs that were never incurred on a balance sheet precisely because they were avoided. Fundamentally, avoided costs are a methodological construct that form the basis for negotiating fairness between system benefits and individual benefits.

Viewed in this light, the VOS functions as a boundary object[63]—a point of negotiation and a neutral price signal for third-party investment on the grid. Negotiating the complexity of the VOS is a problem that is inherent to other boundary objects that are integral to other proceedings that consider distributed energy resources, such as energy efficiency standards, distribution planning, and resource planning. But this complexity is necessary, especially for distributed resources that are to be deployed in an electricity system where even the smallest resources, if deployed over and over, can have ripple effects throughout the system.

Q. Please elaborate on how a VOS balances stakeholder interests.

A. While the VOS aspires to fairly compensate solar generators only for the social value they create, in practice, the VOS operates as a negotiated financial instrument that

[63] Carlile, P. R. (2002). A pragmatic view of knowledge and boundaries: Boundary objects in new product development. Organization science, 13(4), 442-455.

stakeholders shape. However, the ways in which stakeholders influence the VOS are technocratic and—in the ideal case—are deemed valid based on rational consideration of methods and data and transparent decision making.

Further, the VOS must also take definitive positions on complex philosophical questions of fair attribution of costs. Avoided costs are estimated ex-ante: they avoid future costs. But in reality, costs that were ex-ante anticipated to be avoidable may not be avoided at all, as the electric grid's composition changes from what had been a planned counterfactual. There is a possibility of a substantial difference between the ex-ante anticipated avoided costs and the ex-post realized avoided costs, and regulators should consider processes to erect guardrails that protect the public from burdensome outcomes of double paying for an avoided cost that was never avoided. One way to move toward this alignment is by creating positive incentives for utilities to align their investments in infrastructure that can support DERs (e.g. upgrading the hosting capacity of the distribution grid) with the financial structures that will drive DER investment (e.g. a VOS that incentivizes only those DERs that create social value).

Q. How can a value of solar process enable better long-run system planning under conditions of uncertainty?

A. Referring to cost-allocation methodologies in ratemaking generally, the consulting firm EQ research provided insight into how cost of service studies should consider historic costs when looking to the future[64]:

> Allocation methodologies that spread revenue requirements and design rates based on what the system *was* rather than on what it *could become* will hinder efforts to influence what regulators want the system to become.

[64] Morgan, Pamela and Kelly Crandall. 2017. New Uses for an Old Tool: Using Cost of Service Studies to Design Rates in Today's Electric Utility Service World. EQ Research. http://eq-research.com/wp-content/uploads/2017/04/New-Uses-for-an-Old-Tool-FINAL.pdf

> CCOSS [class cost of service study] methodologies must reflect conscious choices about the future of the system rather than past intended and unintended actions that produced what the system is today.

In the long-run, as DER penetration increases, designing a DG outflow tariff that indeed reflects conscious choices about the future will require a broader set of considerations than a VOS can incorporate. As described in witness Sandoval's testimony, an Integrated Distribution Planning framework can bring together many of the more complex considerations of equitable treatment of DERs that are beyond the scope of a VOS. Still, a VOS can be a very meaningful step toward the more holistic planning for DERs that Integrated Distribution Planning envisions. In Minnesota, we are seeing that Xcel Energy, third parties, and regulators are learning more about the distribution system through the increased third-party DER deployment that the VOS has supported. This increased information will help with future distribution planning. Building in feedback, points of formal and informal communication, and shared understanding between utilities and third-party DER developers will be critical for the kind of holistic, collaborative processes that building the grid of the future will require. The VOS is the logical next step toward this future by opening up data, testing cost-allocation frameworks, and building empirically driven platforms for collaboration and negotiation.

Q. Do you have any additional thoughts on the importance of a VOS study and compensation framework?

A. Given its potential impact in shaping a large amount of third-party investment in DERs, and its potential for linking together distinct proceedings, the VOS deserves specific attention. In my view, it is worth spending significant deliberative energy on establishing and continuously refining the VOS so that investment in DERs can grow to meet system needs in a way that can be most beneficial to the public in the short- and long-run. There can also be significant spillover benefits of developing a VOS for other proceedings and decision-making domains.

This rate case is not the only domain in which the complexity of valuing DERs arises, and insights from developing a robust VOS could inform valuation in other key dockets before the MPSC that grapple with the same fundamental issues. Energy efficiency requirements have long-established procedures for recognizing the system impact of end-use energy efficiency measures (e.g. the cost tests based on the costs and benefits of energy efficiency include methodologies for estimating avoided distribution and transmission costs attributable to efficiency measures). Resource planning and distribution planning processes both take a systems-level perspective on investment planning and seek to model how DERs affect the value of alternative investment strategies (e.g. Consumers' IRP establishes effective load carrying capacities for DERs so that DERs' system-value can be compared to dispatchable centralized generation resources).

The reverse may also be true: other proceedings could help establish a starting point for valuation and additional considerations in the VOS. Further, these proceedings also touch on issues that are related to the value that solar provides but that might be excluded from a VOS methodology (as they are in Minnesota), such as reliability, resiliency, avoided distribution O&M, voltage support, and power quality support. Other studies have attempted to quantify these values, and the feasibility of including such values in a new VOS methodology should be considered.[65] Finally, establishing a VOS

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[65] ICF. (May 2018). Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar. Prepared for: The U.S. Department of Energy. Retrieved from https://www.icf.com/-/media/files/icf/reports/2019/icf-nem-meta-analysis_formatted-final_revised-1-17-193.pdf

could set the stage for more complex and innovative forms of DG deployment, such as community solar and third-party owned solar.

VI. CONCLUSION

Q. Please summarize your recommendations to the Commission.

A. Based on my review of the evidence in this proceeding, my experience engaging in and observing the Minnesota development of a Value of Solar tariff, and the findings and conclusions I have reached in this testimony, I make the following recommendations to the Commission:

- Direct Staff to lead stakeholders in development a framework for a comprehensive Value of Solar analysis for Michigan that clearly guides assessment of the "fair and equitable use of the electric grid" as inclusive of all benefits to ratepayers, the utility, and society—including environmental benefits.
- Order Consumers Energy to evaluate the costs and benefits of DG deployment and operations in its service territory based on the comprehensive VOS analysis methodology to be used as the tariff for outflow DG generation.
- Recognizing that establishing such a methodological framework may take some time, implement an interim rate based upon the analysis conducted by Witness Kevin Lucas until such time as a VOS analysis can be completed.

Q. Does this conclude your testimony?

A. Yes.

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
CONSUMERS ENERGY COMPANY	)	
for authority to increase its rates for the	)	Case No. U-20697
generation and distribution of electricity	)	
and for other relief.	)	

DIRECT TESTIMONY

OF

KARL R. RÁBAGO

ON BEHALF OF

THE ECOLOGY CENTER, ENVIRONMENTAL LAW & POLICY CENTER, GREAT LAKES RENEWABLE ENERGY ASSOCIATION, SOLAR ENERGY INDUSTRIES ASSOCIATION, AND VOTE SOLAR

JUNE 24, 2020

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I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. Please state your name, business name and address, and role in this proceeding.

A. My name is Karl R. Rábago. I am the principal of Rábago Energy LLC, a Colorado limited liability company, located at 2025 E. 24th Avenue, Denver, Colorado. I appear here in my capacity as an expert witness on behalf of Ecology Center, Environmental Law & Policy Center, Great Lakes Renewable Energy Association, Solar Energy Industries Association, and Vote Solar (collectively, the Joint Clean Energy Organizations, or "JCEO").

Q. Please summarize your experience and expertise in the fields of electric utility regulation and renewable energy.

A. I have worked for nearly 30 years in the electricity industry and related fields. I have been actively involved in a wide range of electric utility issues across the United States as an expert witness and, in my former role as Executive Director of the Pace Energy and Climate Center, participated as a party in New York rate cases and in Reforming the Energy Vision proceedings.

My previous employment experience includes Commissioner with the Public Utility Commission of Texas, Deputy Assistant Secretary with the U.S. Department of Energy, Vice President with Austin Energy, and Director with AES Corporation, among others.

My experience includes making hundreds of decisions on the record in cases involving avoided costs, rates, tariffs, certificates of need, rulemakings, and other proceedings. I have also held executive responsibility for managing public and private budgets of up to hundreds of millions of dollars. A detailed resume is attached as Exhibit CEO-20 (KRR-

1).

Q. Have you ever testified before the Michigan Public Service Commission or other regulatory agencies?

A. Yes. I have testified in several proceedings before the Michigan Public Service Commission ("Commission" or "MPSC"), including recent I&M, DTE, and Consumers Energy rate cases, several avoided cost cases, and other proceedings. In the past six years, I have submitted testimony, comments, or presentations in proceedings in Alabama, Arkansas, Arizona, California, Colorado, Connecticut, District of Columbia, Florida, Georgia, Guam, Hawaii, Indiana, Iowa, Kansas, Kentucky, Louisiana, Massachusetts, Michigan, Minnesota, Missouri, Nevada, New Hampshire, New York, North Carolina, Ohio, Pennsylvania, Puerto Rico, Rhode Island, Vermont, Virginia, Washington, and Wisconsin. I have also testified before the U.S. Congress and have been a participant in comments and briefs filed at several federal agencies and courts. A listing of my previous testimony is attached as Exhibit CEO-21 (KRR-2).

Q. What is the purpose of your testimony?

A. In this testimony, I will review and offer recommendations to the Commission regarding issues arising in the Application of Consumers Energy Company ("Company") for authority to increase its rates for the generation and distribution of electricity, and for other authority. In particular, I will address the Company's proposed Distributed Generation Tariff ("DG Tariff").

Q. What information did you review in preparing this testimony?

A. I reviewed relevant pre-filed testimony of Company witnesses, filed Company schedules and tables, relevant Michigan laws, and relevant Company responses to information requests submitted by the JCEO and other parties. I also reviewed prior Commission decisions, as well as prior testimony of my own.

Q. Please summarize your recommendations to the Commission.

A. Based on my review of the evidence in this proceeding and the findings and conclusions that I have reached, I make the following recommendations to the Commission:

(1) The Commission should reject the Company's DG Tariff proposal because it is both inconsistent with law and unsupported by competent evidence establishing that it would result in just and reasonable rates for DG customers.

(2) The Commission should reaffirm that a separate rate class for net metering customers is neither necessary nor appropriate.

(3) The Commission should approve an interim DG Tariff based on the analysis conducted by witness Mr. Kevin Lucas. While I agree with the Company that inflow rates for the DG Tariff should be based on the customer's otherwise applicable consumption rate, Mr. Lucas' analysis demonstrates that the outflow credit should be set at $0.23957 per kWh with an additional credit for the reduced cost to serve DG customers.

(4) The Commission should order the Company to conduct a comprehensive Value of Solar study[1] and, in conjunction with accurate cost of service data, develop a DG Tariff proposal based on equitable cost of service for both inflow charges and outflow

[1] This testimony uses the term "value of solar" to reference a comprehensive characterization of the net benefits and costs to the grid and society resulting from the generation of energy from a distributed, net-metering generation facility. As JCEO witness Chan describes, such analysis can be used as a foundation for evaluation of the value of all manner of distributed energy resources, including distributed generation, distributed storage, demand response, and others.

credits.

II. LEGAL, REGULATORY, AND ECONOMIC CONSIDERATIONS RELEVANT TO THE DG TARIFF PROPOSAL

Q. What is your overall assessment of the DG tariff issue before the Commission in this case?

A. This case presents the Commission with an opportunity to establish a mechanism for ensuring that any DG tariff approved under MCL 460.6a(14) rests upon competent, material, and substantial evidence that the tariff's inflow charges and outflow credits reflect equitable cost of service for utility revenue requirements for customer-generators. In particular, this case allows the Commission to move away from formulaic rates established under old law in the MCL 460.1177(4)-based net metering and modified net metering programs and implement the cost- and benefit-based rates for inflows and outflows required of the DG Tariff under current law.

Q. What is your understanding of how the Commission has interpreted its statutory authority to approve rates for the DG Tariff?

A. Under MCL 460.6a(14), the Commission enjoys broad authority and discretion to fashion and approve "an appropriate tariff reflecting equitable cost of service for utility revenue requirements for customers who participate in a net metering program or distributed generation program under the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001 to 460.1211."[2] In rate cases filed after June 1, 2018, the Commission ordered rate-regulated utilities to file an Inflow/Outflow tariff, and if the

[2] MCL 460.6a(14).

utility chose to, it could at that time also file its own alternative tariff.[3] Under the discretion granted to it by the Michigan Legislature, the Commission could approve a tariff that included two-channel billing, where separate rates are assessed for the billing period totals on each of the "inflow" and "outflow" registers on the customer's meter. Alternatively, the Commission could allow for netting of these amounts at the end of the billing period, with a separate rate for "outflows that exceeded inflows" during the period.

Consistent with its broad authority and discretion, the Commission has a wide range of options for setting inflow and outflow rates as long as the rates are based on equitable cost of service. The Commission could set the inflow rate based on the COS-based rates charged for non-generating customers in the customer class, or upon a separate COS study for generating customers. The Commission could set the outflow rate based on wholesale rates, the embedded power supply rate, or any combination of wholesale, power supply, transmission, and/or distribution charges, so long as it is based on equitable cost of service. The Commission can also approve charges on DG customers or additional credits for DG, so long as those charges and credits are cost-based. The Commission can also determine how credits for excess generation are applied against bills. And, based on proposals from rate regulated utilities, the Commission could approve a DG tariff that was based on something other than the Inflow/Outflow method.

Q. In your view, what considerations should guide the Commission's evaluation and approval of DG tariffs?

[3] *See* Docket No. U-18383, April 18, 2019, Order at 18.

A. The touchstone for Commission determinations on this issue is the statutory phrase "equitable cost of service" from MCL 460.6a(14). Like all rates, DG rates must be just and reasonable.[4] Michigan Public Act 342 of 2016, from which the Commission's broad discretion and authority is derived, amended Michigan Public Act 295 of 2008, which has, among its purposes, the diversification of energy resources, greater use of indigenous energy resources, and more private investment in renewable energy.[5] For more than one half a century, regulators have also looked to the principles of public utility rate making articulated by James Bonbright in 1961.[6]

Q. What guidance is offered from Bonbright's treatise?

A. Bonbright's Principles of Public Utility Rates are often summarized as three: (1) revenue requirement, (2) fair apportionment of costs among customers, and (3) optimal efficiency. These principles have been elaborated on as focusing on the utility's revenue requirement, fair apportionment of costs among customer classes, and optimal efficiency in consumption of electricity as a commodity. In addition, Bonbright instructed that rates must be simple, understandable, acceptable, free from controversy in interpretation, stable, and non-discriminatory.

Q. How do these principles apply to the evaluation of the Company's proposed DG tariff?

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[4] MCL 460.6g(2).
[5] PA 342 § 1(2).
[6] Bonbright, J.C., 1961. Principles of Public Utility Rates. 1st ed. Columbia University Press. Available at: https://www.raponline.org/knowledge-center/principles-of-public-utility-rates/.

A. The Bonbright Principles inform the evaluation of the Company's DG tariff proposal in several ways. In addition to being simple, understandable, acceptable, free from controversy in interpretation, stable, and non-discriminatory, to comply with Michigan law while also meeting widely accepted principles of public utility ratemaking, the Company must submit competent and substantial evidence that establishes that:

- The Company has incurred costs that support the revenue recovered under the DG Tariff; that is, that customer-generators are responsible for the revenue requirements imposed upon them by the DG Tariff.
- The costs the Company seeks to apportion to customers under the DG Tariff are fair, just, and reasonable.
- The proposed rate is economically efficient and accounts for all the costs and benefits associated with customers' use of distributed generation.

Q. Do modern utility and electricity service conditions merit adaptation of Bonbright's principles?

A. Yes. While the core principles remain valid, some things have changed since Bonbright published his work. Today, utilities are not the only investors with skin in the electric service game—customer generators are significant investors, too. And customer classes are becoming more diverse, not less so. As a result, the tools and metrics of economic efficiency require attention to far more factors than the price revealed by a century-old approach to cost- of-service accounting. There is important work to do in ensuring that public utility rates impacting distributed generators serve and support the public interest. I therefore recommend several modern adaptations of Bonbright's principles that the Commission should rely upon in reviewing the underlying methods and foundation for the Company's proposed DG Tariff, and to ensure that equitable cost-of-service based rates are in place for DG customers. These additional considerations are:

- Full comprehension and reflection of the resource value of DG in DG tariffs.
- Rates should account for the relative market positions of the various market actors, and especially for the information asymmetries among customers, utilities, and other parties.
- Rates must be grounded in a careful assessment of the practical economic impacts of distributed energy resource ("DER") [7] rates, including DG rates, on all market participants.
- DG rates, like utility rates in general, must support capital attraction for beneficial investments.
- Regulation must account for the incentive effects of DER and DG rates.
- Rates for DG and other DERs require accurate accounting for utility costs and careful differentiation between cost causation and the potential for cost shifting.

Q. Please explain why full comprehension and reflection of resource value is essential for just and reasonable DG rates.

[7] This testimony and the general practice in the industry uses the term "distributed energy resources" to describe a wide range of technologies and services deployed in the distribution system to meet demand for energy services. These technologies and services include generation, storage, electric vehicles, energy efficiency and conservation, demand response, and demand management. The tariff at issue in this case addresses only a subsection of DERs, which are referred to as "distributed generation" or DG, and as a practical matter in Michigan are small residential and commercial solar installations.

A. Regulators should fully comprehend and reflect resource value in rates.[8] Typically, comprehension should be supported by full assessment of costs and benefits resulting from DER/DG operation, and where possible, quantification of those impacts for use in cost of service analysis and rate design. Regulation is complex, even more so in an era of DERs and increasingly competitive markets. Rates are often based on embedded historical costs yet have their most profound impact on future behaviors and costs. The growing menu of cost-effective DER-based services and increasing customer choice compels an analysis and explicit reflection of costs incurred by utilities, costs avoided by utilities,[9] and benefits enjoyed by utilities in basic service and optional rates like the DG Tariff because the rates impact DER investment and utilization, and are a key mechanism for implementing the goals of PA 342. Full data-driven evaluation of costs and benefits of DG has been a constant theme in the work on successor rates to traditional net metering by the Commission Staff ("Staff"), but that data-driven work remains to be done. Regulators in many states increasingly recognize that there are significant and challenging gaps between costs, prices, and value in the electricity sector. Regulators are also seeking refinements in costs and benefits based on locational and temporal

[8] Parties in the recent DTE general rate case presented proposals for evaluation and consideration of value-based adjustments to the proposed DG tariff, but the Commission found the evidence insufficient to support a specific adjustment under the facts of that case. Commission Order, U-20162 (May 2, 2019) at 194.

[9] Here, the term "avoided costs" means full avoided costs, including all the known and measurable costs avoided by the operation of distributed generation over the life of the generation facility. This usage stands in contrast to the much more limited usage which only quantifies avoided wholesale energy costs, typically derived from averages of locational marginal prices.

characteristics of the operation of DG and other DERs. Economic efficiency requires conscious engagement with objective, data-driven valuation processes.

Q: How would you recommend the Michigan Public Service Commission engage in such a process?

A: I recommend that the Commission order the conducting of a comprehensive Value of Solar study, including analysis of the impacts of power outflows to support DG rates in Michigan in order to ensure allegiance to the statutory requirement of equitable cost of service-based rates.

Q. Why is accounting for the relative market positions of and information asymmetries between market actors important?

A. The determination of just and reasonable DG tariff rates should account for the relative market positions of the various market actors, and especially for the information asymmetries among customers, utilities, and other parties. Utilities hold all the relevant data necessary to quantify appropriate cost of service-based rates. As this testimony sets out in detail, the Company has failed to produce, gather, or rely upon the data necessary to ensure that its proposal for a DG tariff, including charge and credit values, meets the statutory requirement with clear and convincing evidence.

Q. Why is it important that rates be grounded in a careful assessment of practical economic impacts?

A. A just and reasonable distributed generation rate must be grounded in a careful assessment of the practical economic impacts of the rate on all market participants. Without this assessment, a sub-optimal amount of distributed generation will be installed.

This testimony identifies the miniscule fraction of Company economics represented by the actions of customer generators and the glaring lack of reliable data upon which the Company purports to base its assessment of the proposed DG outflow rate. The Company has conducted no analysis of the impacts of the proposed DG tariff provisions on DG customer bills.[10] Importantly, this also means that there is insufficient evidence in the record to fully assess whether the Company's proposed DG rate will have the effect of impairing the clean energy goals of PA 342 and leading to unnecessary and unwarranted impairment of the quality and character of Michigan's energy supply. Certainly, it is clear that less renewable DG, now and over the coming decades, will be worse for Michigan's environment. Any DG investment discouraged by economic impacts of DG outflow compensation rates will deny Michigan the benefit of decades worth of non-polluting electricity generation.

Q. Why is it important that rates support capital attraction for non-utility market participants?

A. Discouraging DG investment denies all customers of the benefit of private, non-utility coverage of insurance, financing, and operational costs associated with generation, and preserves more expensive monopoly control over system costs—costs that are imposed on all customers. An unreasonably and unjustifiably low outflow compensation rate in a DG Tariff will impair the development of renewable energy markets in Michigan and harm customers who are interested in developing DG projects. DG investments require capital, and this capital investment represents a proportionately more significant share of a household or business budgets than the same investment would for a very large utility.

[10] Company response to ELPC-CE-079, attached hereto as Exhibit CEO-22 (KRR-3).

Capital access and affordability for small investors is impacted by payback rates and ratios, market size, supply- and value-chain diversity and maturity, and other factors. The rate regulated utility must provide enough competent evidence for the Commission to evaluate whether the proposed DG Tariff will have an unreasonable and sub-optimal negative impact on capital attraction to support renewable energy market growth in Michigan.

Q. Why is it important for the Commission to bear in mind the incentive effects of DG rates?

A. It is a truism of economic and rate regulation that "all regulation is incentive regulation."[11] Likewise, all rate design is incentive rate design. As previously explained, DG outflow rates impact DG investment decisions. There are other potential incentives stemming from DG Tariff design as well. An inadequately understood and analyzed DG Tariff approved by the Commission creates significant risk of energy waste, economic inefficiency, and in increased environmental harm:

- A significant differential between inflow and outflow rates will encourage customer-generators to use as much generation onsite as possible.[12] While this might have the effect of encouraging additional investment in storage technology by customers that can afford it, it will primarily encourage customers to time their energy consumption during periods of higher DG output. As a result, valuable on-peak energy production

[11] Lazar, "Electricity Regulation in the U.S.," Regulatory Assistance Project (Jun. 2016). Available at: https://www.raponline.org/knowledge- center/electricity-regulation-in-the-us-a-guide-2/.
[12] This was recognized by the Commission in the DTE rate case, Case No. U-20162, at 190.

that otherwise could have offset expensive utility generation will be unavailable to the grid at large.

- Unreasonably low outflow rates that do not reflect the full value of exported generation will encourage uneconomic undersizing of DG systems. DG systems are heavily driven by fixed costs—as are utility investments—and the relative cost of incremental capacity is falling. Undersizing systems to avoid production that does not earn full and fair value for generation results in economic waste and, again, denies to the entire electricity grid the benefits of excess generation that the larger system could provide.
- Unreasonably low outflow rates exacerbate the problem of subsidies flowing from customer-generators to the utility and other customers. Excess energy from DG customers backs down utility generation and reduces loading on transmission and distribution systems—often during peak hours when marginal losses are higher. These benefits of distributed generation are only partially accounted for and not at all studied by the Company in this application. Moreover, excess generation is not stored by the utility, but immediately serves the nearest unserved load as a simple matter of electrical physics. As the energy serves that load, it passes through a utility revenue meter, earning the utility a full billing charge at the applicable retail rate.[13] This means that the utility collects a full retail rate's worth of revenues, which includes allocated charges for fixed costs recovery, for every kWh of export from a DG facility. And because billing systems have very small variable costs and the distribution system is already in place, the only amount the utility pays for the

[13] *See* CEO-23 (KRR-4) Company responses to ELPC-CE-074, ELPC-CE-893, ELPC-CE-894.

energy—energy that it otherwise would have had to generate or purchase, transmit, and distribute—is the DG Tariff outflow rate.

- Outflow rates that do not reflect full lifecycle environmental costs and full value of outflow have the effect of extending and exacerbating uneconomic costs for electricity service that fail to internalize known, measurable, and significant environmental costs associated with non-renewable generation and inefficient utility system operations.

Q. Why is careful accounting for utility costs important?

A. Just and reasonable rates for DG require accurate accounting for utility costs and careful differentiation between cost causation and the potential for cost shifting. As addressed later in this testimony, the Company has not conducted any meaningful and reliable analysis to support its assertions about the costs of DG operations. In addition, the Company asserts that customer-generators avoid paying for costs without any credible evidence of the cost of service basis for those assertions. The Company correctly asserts that, all other things being equal, customer-generators don't pay as much for their utility bill as they would have without a DG system. The Company is also correct that, all other things being equal, customer-generators make lower contributions to fixed cost recovery as they would have prior to installing their DG system.The fundamental principle of cost-based rates is that customers who make greater use of the system pay for that greater use, and that customers who make less use of the system pay at an appropriately lower level.

Q: What is the difference between cost causation and cost shifting, and why is it important?

A: Cost causation is usage that creates new or incremental costs; cost shifting is a change, approved by a regulator, of the ultimate rate and customer that bears the caused cost. The Company fails to provide any evidence for how the cost to serve a DG customer changes as a result of DG operation. Customer-generators seek to reduce use of utility energy services, but reduction in use does not and cannot *create* costs in a cost of service rate making regime. Indeed, down to the level of the most basic costs to connect a customer, reductions in use mean reductions in caused costs. Customer use reductions compared to forecasts *may* result in a potential for a shifting of costs in a subsequent rate case, and such cost shifting *ma*y merit regulatory attention of several different kinds. The Company has failed to provide any evidence to support a just and reasonable quantification and treatment of any such cost shifts or to demonstrate in any meaningful way the potential cost shifts are sufficiently significant to justify adjustment through the DG tariff.

Q. To the extent that reductions in use by customer-generators create the potential for cost shifts, what should a reasonable and prudent utility do?

A. As this testimony reiterates, the first step the Company should take is to objectively quantify the potential cost shift associated with distributed generation. That step remains to be done by the Company. The second step is to assess the potential cost shift in the context of other potential cost shifts.[14] The Company has not assessed the relative magnitude and significance of any potential cost shift that might be associated with DG operations.

Q. Please provide examples of other potential cost shifts.

[14] Potential cost shifts become real cost shifts through a rate case order or other Commission order approving a rate or tariff.

A. Potential cost shifts arise for two major reasons. Most commonly, they arise from the averaging of costs into rates within a class of diverse customers with diverse usage patterns. For example, residential customer charges based on class-wide average costs create a cost shift by which multi-family customers bear a disproportionate share of costs associated with service drops, final step-down transformers, and other infrastructure associated with electricity delivery, as compared with residential customers who live in large suburban homes. This is because a single service drop in a multi-family dwelling serves multiple customers, while a suburban drop may serve as few as one customer per line. Customers with usage patterns that do not contribute to system peak costs as much as other customers in the class bear disproportionate costs under average rates as well. Customers that invest in major energy efficiency improvements reduce their use and contribution to fixed cost recovery. If rates have been set based on an assumption that these customers would continue their inefficient use in the rate case forecasts, that would set up a potential cost shift in the next rate case. And utility economic development rates often shift costs from new load customers to existing customers based on a hope that increases in usage will lead to cost shifts in the opposite direction at some time in the future. In my experience, the magnitude of the potential cost shifts associated with these examples dwarf the potential for cost shifts associated with DG operations even without full and fair consideration of the costs and benefits of DG operations to the grid.

Q. If the potential cost shifts associated with DG operations are likely to be very small, what does this say about the Company proposal in its DG tariff?

A. In the absence of credible evidence of a significant cost shift that must be addressed in order to ensure just and reasonable rates for all customers, and in the face of likely greater potential cost shifts associated with other factors, the Company proposal is unjustified as a rate proposal. A focus on significant cost shifts of different kinds already embedded in rates would advance administrative economy and efficiency.

Q. What then should the Company do in order to ensure that it is proposing just and reasonable rates for DG customers?

A. The Company should conduct load and generation sampling and conduct research to determine how the installation and operation of DG facilities impacts the costs to serve DG customers and propose an inflow charge that is based on actual cost of service. Second, the Company should fully and objectively assess the impacts on the grid of DG outflow in order to support a just and reasonable outflow rate proposal. The Company has not done these things. As discussed later in this testimony, JCEO witness Kevin Lucas conducted an analysis of Company data that supports an outflow rate that the Commission should approve. If the Commission does not accept the rate proposed by Mr. Lucas, then until the Company can produce actual data to support its proposed DG tariff, it should continue to credit outflows at the full power supply rate including transmission and distribution charges—that is, at the full retail rate.

III. ENVIRONMENTAL IMPAIRMENT CONSIDERATIONS RESULTING FROM THE PROPOSED DG TARIFF

Q. You raised the issue of negative environmental impacts from the discouragement of otherwise economic DG investment as a result of the Company's proposed DG tariff. Why does environmental impairment matter and how does it come about as a result of an electric utility's DG tariff?

A. As the Commission has recognized, section 1705(1) of the Michigan Environmental Protection Act ("MEPA")[15] provides that any person may intervene in an administrative proceeding by filing a pleading asserting that the proceeding "has, or is likely to have, the effect of polluting, impairing, or destroying the air, water, or other natural resources."[16] In a proceeding where an intervenor has made this allegation, such as an IRP proceeding, "the alleged pollution, impairment, or destruction of the air, water, or other natural resources . . . shall be determined, and conduct shall not be authorized or approved that has or is likely to have such an effect if there is a feasible and prudent alternative consistent with the reasonable requirements of the public health, safety, and welfare."[17] The Commission found that MEPA did apply to the DTE integrated resource plan ("IRP") proceeding, because the allegation of impairment had been made by intervenors. The Commission concluded that "it is appropriate to determine under MEPA: (1) whether the IRP would impair the environment; (2) whether there was a feasible and prudent alternative to the impairment; and, (3) whether the impairment is consistent with the promotion of the public health, safety, and welfare in light of the state's paramount concern for the protection of its natural resources from pollution, impairment or destruction."[18]

Q. Are you alleging that environmental impairment is likely to result from adoption of the Company's proposed DG tariff?

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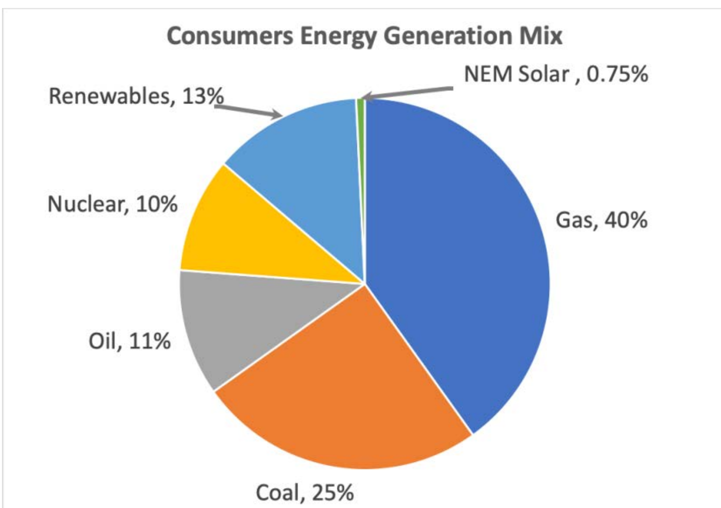
[15] MCL 324.1705(1)
[16] Case No. U-20471, MPSC Order, at 42 (Feb. 20, 2020).
[17] *Id.* at 43, *citing* MCL 324.1705(2)
[18] *Id.*

A. Yes. While the precise impacts of the DG tariff cannot be assessed due to the lack of competent evidence in the Company's case application, the proposed limit on outflow compensation to the power supply amount, without transmission, will reduce the number of potentially cost-effective solar installations and therefore result in more atmospheric and other pollution than would occur without those DG installations.[19]

As Figure KRR-1 shows, the Consumers Energy generation mix is about three-quarters fossil energy based. DG accounts for less than one percent of the mix. A DG tariff that reduces the deployment of DG against the market potential level of DG necessarily means continued reliance on polluting resources.

Figure KRR-1: Consumers Energy Generation Mix



Q. What course should the Commission take in light of this allegation?

A. As I have explained, the Commission may only approve a Company DG tariff that is just and reasonable. Compliance with section 1705(1) of MEPA is necessary to support a just and reasonable DG tariff rate. The Commission must have sufficient evidence to

[19] *See* Exhibit CEO-24 (KRR-5) Company response to ELPC-CE-898.

conclude that the DG Tariff would impair the environment. As I explained above, a DG Tariff that is not cost-based and fully values all aspects of DG would result in suboptimal development of DG projects, which will have a negative impact on the environment. The Commission must also determine whether there is a feasible and prudent alternative to the proposed DG Tariff. As I explained above, the Commission could require a Value of Solar analysis that provided sufficient data to set cost-based inflow and outflow rates, optimizing the installation of DG projects. Finally, the Commission must consider whether the impairment to the environment is consistent with the promotion of the public health, safety, and welfare in light of the state's paramount concern for the protection of its natural resources from pollution, impairment or destruction. The Commission does not have sufficient evidence from the Company on the impact of its DG Tariff to make this determination.

IV. PRIOR COMMISSION DECISIONS REGARDING DG TARIFFS PROPOSED BY RATE REGULATED UTILITIES

Q. What has the Commission approved in cases filed and decided since 2018?

A. For DTE Electric Company, in Case No. U-20162, the Commission approved a DG tariff rider with an inflow credit based on the otherwise applicable consumption tariff applicable to the customer-generator's customer class, and an inflow credit that did not include monthly netting based on embedded power supply costs less transmission costs. For Indiana Michigan Power Company the Commission approved settlement agreements in Case No. U-20359 that included an non-netted outflow credit based on embedded power supply costs and including transmission costs, that is, the capacity and non-capacity power supply charges approved in the tariff applying to the customer.[20] For Upper Peninsula Power Company, in Case No. U-20276, the Commission approved a settlement that provides for a monthly outflow credit equal to the power supply component.[21] The variety of these outcomes showcases that the Commission has broad discretion and authority to continue to work towards a DG Tariff that truly reflects equitable cost of service.

Q. Have any of the DG tariff cases decided by the Commission involved comprehensive evaluation of the costs and benefits of DG?

A. No. For the settled cases, the settlement agreement and order provisions relating to the DG outflow credit are not tied to any calculation or analysis of the costs and benefits of DG outflows or the cost of serving DG customers. For the DTE case, the Commission expressly rejected a proposal for an outflow credit based on the wholesale market locational marginal price ("LMP"), agreeing with staff that such a credit would be "*de minimus*," and approved the Administrative Law Judge's recommendation to base the outflow credit on power supply less transmission.[22] The Commission agreed with Staff that, under the facts of that case, excluding avoided distribution and transmission costs in the outflow credit means that customer-generators are "contributing to these charges consistent with COS principles."[23] The Commission further found that the outflow credit it approved was not in conflict with MCL 460.1177(4)(b), though it also noted that the

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[20] Order in U-20359
[21] Order in U-20276 at 3. The Commission's order does not specifically state that transmission costs are excluded from the power supply component, so it appears that they are not excluded.
[22] U-20162 at 180.
[23] *Id.* at 181.

outflow credit based on power supply less avoided transmission costs was not the only path that could be taken in designing a DG tariff. However, the Commission did not rely on a power-outflow study produced by DTE, any comprehensive Value of Solar analysis, or a study of the cost to serve DG customers. The Commission declined to order a power-outflow study in its Order, finding that such a study would be premature,[24] even though the Staff had recommended that "the Company undertake a capacity study to confirm that coincident aggregate program outflows are relatively stable and predictable and to quantify the effective DG outflow capacity and value."[25] The Commission further rejected a proposal to calculate and include a market transition adder stating concern that the limited evidence in the proceeding pointed toward the possibility of an unjustified subsidy to DG customers resulting from such an adjustment, but cited a lack of record evidence to support a calculation at all.[26]

Q. In your opinion, where do the prior Commission decisions position the determination of a just and reasonable, cost of service-based DG tariff outflow rate in this case?

A. The Commission made it clear in its Order in Case No. U-18383, cited in its decision in the DTE case,[27] that the determination of an appropriate outflow credit is ultimately a fact- and data-based evaluation:

> The cost and benefit impacts associated with DG customers are not static, but can vary based on a multitude of factors including location, utility infrastructure conditions, weather, and the number of DG customers on the grid, among other

[24] *Id.* at 182.
[25] *See id.* at 178.
[26] *Id.* at 193.
[27] *Id.* at 193-194.

factors.[28]

The question at issue in this proceeding is whether the Company has provided sufficient evidence to support a determination that the outflow credit proposed for its DG tariff reflects equitable cost of service for utility revenue requirements for customer-generators. The Company has failed to present competent, material, and substantial evidence to support its proposed DG tariff.

V. OVERVIEW OF COMPANY PROPOSED MODIFICATIONS TO DG TARIFF

Q. Generally, what does the Company propose regarding its DG tariff in this case?

A. The Company, primarily through the testimony of witness Hubert Miller III, proposes to replace traditional net metering with an "inflow-outflow" rate design for customer generators. The rate design eliminates netting over the billing period in favor of a two-channel billing approach that sets one rate—based on the consumption rate otherwise applicable to the customer's class—for inflows of electricity, and then sets another rate—based on energy production costs—for outflows of customer generation, sometimes called "excess," "exported," or "injected" energy.

Q. Do you support the inflow/outflow structure as a mechanism for implementing a DG rate?

A. I agree, in general, with the Company[29] and the Commission Staff that the inflow/outflow method provides a reasonable foundation for accounting for the costs and benefits—the economic impacts—of DG operations. In fact, the idea of more precisely characterizing and quantifying the impacts of consumption and export was a key consideration of mine

[28] Order in U-18383 at 11.
[29] Miller at 21.

when I developed and implemented the first Value of Solar Tariff in Austin almost ten years ago. The key element of the inflow/outflow method is that it is a tariff design that depends on the values that are used to set the inflow charge and the outflow credit. Both Staff and the Commission appear to have indicated that it is the inputs rather than the structure of the tariff that ensures fairness, adherence to cost of service principles, equity, and economic efficiency.

Q. Do you also agree with the Company and others that traditional net metering is inherently flawed because under net metering the customer "avoids paying for their use of the system?"[30]

A. No. This kind of statement makes no sense in the absence of a comprehensive measurement of the impact of DG customers on the electric service system. It has been empirically demonstrated in several of the studies cited and summarized in the ICF meta-analysis discussed later in this testimony that net metering can result in net benefits that exceed costs. This means that even full retail rate compensation for excess production would result in DG customers subsidizing the utility and other customers. The point is that such categorical exclamations as made by the Company witness about net metering are meaningless in the absence of real data.

Q: How should Company Witness Hubert Miller III have approached his analysis?

A: As this testimony repeatedly demonstrates, the Company has not brought the data to this proceeding that is required to support their conclusions, and ultimately, their proposed DG Tariff. As JCEO witness Kevin Lucas explains, the time interval used through the

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[30] Miller at 23.

Company's cost of service analysis and method is one hour. Because of this time interval, a two-channel or "instantaneous" billing-based DG tariff cannot serve the legislative requirement for equitable cost of service. In addition, the Company takes a view of cost that focuses exclusively on potential cost *shifts,* and that is only a small fraction of the total equitable cost of service associated with DG customers. As explained in detail in the testimony of Mr. Ronny Sandoval on behalf of the JCEO, the Company has not performed an analysis of the benefits of DG operations on its grid. Company Witness Miller should have sought the data and analysis in the Company's possession and provided that to the Commission in support of his conclusions.

Q. Are you asserting that net metering does not create the potential for near-term cost shifts between customers within a class?

A. No. Cost-shifts in the near term are possible any time current customers pay for benefits that will be realized over the long term by future customers. Cost shifts can occur when a utility fails to adequately forecast the rate of DG adoption or, for that matter, any customer behavior or investment that results in reduction of usage. But cost shifts are not cost causation. When a DG customer or any customer employing a load-reducing DER measure or technology reduces their use, they do not thereby create a cost. Rather, by using less energy from the utility, they reduce their charges and potentially create a shortfall in the amount of revenue the utility erroneously believed they would collect from that customer.

Q. Should customers be forced to pay for the sunk fixed costs of the utility system regardless of their level of usage?

A. No. The rate making model in the United States is based on cost of service. Low users create lower costs than high users. Users who reduce their costs by reducing their use—through self-generation or any other method—should not be forced to pay for system costs they do not create. The premise of the Company's assertion is founded on an erroneous conflation of sunk and fixed costs.

Q. Please explain how sunk and fixed costs are different and why that matters in setting fair, cost-based rates for DG customers.

A. It is first important to recognize the immense market power difference between a monopoly utility and its customers. A key reason for tariffed rates is this difference in market power. Tariffed rates are a special kind of contract for service under which the agreement—the provision of a particular service at a specific rate—is made binding simply by the act of acceptance by a qualified customer. There is no negotiation for residential customers because there could not be a fair negotiation between a monopoly and its captive customer. Moreover, customers accept the terms of the tariff through subscription and use—not through non-use. Fixed customer charges and other non-bypassable charges are kept small in order to improve the economic efficiency of consumption- or demand-based rates as a price signal. What this all means is that just because the utility sees a fixed cost as a sunk cost in the short term, it does not mean that fixed costs should be collected from customers regardless of the level of the customer's use of utility-supplied energy. Not all fixed costs are sunk. Indeed, over the long term, all costs are variable. Many utilities are today evaluating so-called "Non-Wires Solutions" projects that deploy high concentrations of DER in order to avoid or defer imminent fixed cost investments. Volumetric charges for residential energy use, even where time-differentiated, send efficient price signals to residential customers because changes in use mean changes in cost-causation. Charging (or decrementing the outflow credit) because customer-generators use less energy than they would have without DG or less energy than an average customer in the class, in the absence of cost of service data based on actual costs and usage, is discriminatory, punitive, and economically inefficient. This is why "take or pay" rates are not used in residential electric rate making. This is the flaw in the basic argument by the Company that DG customers, by reducing use, avoid paying their fair share of utility fixed costs.[31] The argument assumes that non-use of the grid and non-cost causation should be charged for in the same manner as usage and cost-causation. Worse, if the Company argument is accepted without evidence of cost-causation, it will send an inefficient price signal to the utility—a signal that overbuilding or gold-plating the grid will be charged to customers regardless of use. Finally, there is no logical stopping point once a utility is allowed to charge customers for supposed or planned use instead of actual use. Customers that install efficiency measures or simply practice conservation also reduce their use and their contribution to projected revenue recovery.

Q. How does the Company justify its proposal to charge customers at the consumption rate applicable to other members of the customer-generator's class?

A. The Company offers no justification for the charge and references no cost of service or other empirical data to support charging the full consumption rate for inflows under the proposed DG tariff. Company witness Miller states that while "some stakeholders" argue

[31] Miller at 27. Company witness Miller appears to be advocated straight fixed variable rate design for DG customers and all customers when he states that "there is still a subsidy issue with rate designs that primarily recover fixed costs through volumetric charges."

that DG customers are less costly to serve than other customers, "the Company has not seen any compelling evidence to suggest this is the case."[32]

Q. Does the fact that the Company "has not seen any compelling evidence" regarding the cost to serve DG customers justify its assumption that an inflow charge based on the consumption rate for the non-generation customers in the class is cost-based, equitable, and, as a result, just and reasonable?

A. No. It does not matter whether the Company has *seen* generalized evidence of the cost to serve DG customers. The Commission made this clear in its order in U-18383:

> The cost and benefit impacts associated with DG customers are not static, but can vary based on a multitude of factors including location, utility infrastructure conditions, weather, and the number of DG customers on the grid, among other factors.[33]

The issue is whether the Company has measured and analyzed the costs to serve its DG customers in order to determine the relative costs of serving those customers and in order to propose an equitable cost of service-based rate for its own customers.

Q. Is there evidence in the public domain in the form of utility studies that casts light on what utilities and analysts have found regarding the costs and benefits of distributed generation?

A. Yes. There are many studies in the public domain that establish that the benefits of DG operations exceed the costs, even under traditional net metering. While these are generally not reports based on cost of service studies, per se, the evidence that they provide is whether net benefits exceed net costs from a variety of perspectives and over a

[32] Miller at 26.
[33] Order in U-18383 at 11.

range of assumed benefits and costs. The fact that many of these studies in recent years show net benefits from DG operations strongly suggests that DG customers have lower costs of service and create additional system wide benefits in the form of avoided system costs. The Company had good reason—Michigan's energy law requiring a rate based on equitable cost of service[34]—to collect reliable data and determine how customer investment in DG impacts the cost to service those customers as well as the costs to continue serving other customers on the grid. In addition, Mr. Miller III could have consulted a study authored by Galen Barbose at Lawrence Berkeley National Laboratory, entitled "Putting the Potential Rate Impacts of Distributed Solar into Context," which was published in the 2017.[35] The study finds that:

> [F]or the overwhelming majority of utilities, current PV penetration levels are far too low to result in any discernible effect on retail electricity prices, even under the most pessimistic assumptions about the value of solar and generous assumptions about compensation provided to solar customers (e.g., full NEM [net energy metering] with volumetric rates).[36]
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> * * *
>
> Most utilities are thus quite unlikely to see any appreciable effects of distributed solar growth on retail electricity prices. For example, even if one were to assume that distributed solar had zero net value to the utility (an extremely pessimistic assumption), and that all PV generation was compensated under net metering with purely volumetric retail rates (a relatively favorable scenario for solar customers), a 1% penetration would result in just a 1% increase in average retail electricity prices. Relative to projected U.S. average electricity prices in 2030, this equates to a 0.1 cents/kWh increase. Most utilities are unlikely to see an effect even of this magnitude, given more-realistic assumptions about the value of solar and a lower solar compensation rate for most commercial and many residential customers.[37]

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[34] MCL 460.6a(14)

[35] G. Barbose, Putting the Potential Rate Impacts of Distributed Solar into Context, Lawrence Berkeley Nat'l Lab. (Jan. 2017), available at: https://emp.lbl.gov/publications/putting-potential-rate-impacts.

[36] *Id.* at 10.

[37] *Id.* at 11.

In addition, Mr. Miller could also have consulted a meta-analysis of studies from fifteen diverse states prepared for the U.S. Department of Energy by ICF, published in May 2018, each addressing the value of solar DG and the cost effectiveness of net metering programs.[38] In particular, the ICF study provides summaries of the fifteen studies that show that in the overwhelming majority of the studies, net metering rates and value-based net metering successor rates were found to be cost-effective.[39]

Q. What lesson do these studies provide for the Company regarding the cost to serve DG customers?

A. The evidence in those studies (and the studies referenced therein), as well as the obligation to provide competent, material, and substantial evidence to support its own proposal, compel the Company not to passively wait until it has seen the evidence upon which to base a tariff. The Company must proactively and comprehensively measure and analyze the costs of serving its own DG customers and how those costs are impacted by the various factors cited by the Commission in Case No. U-18383.

Q. Even though the Company did not proactively study the costs to serve DG customers, does it nevertheless have a view on the magnitude of those costs?

A. Yes. The Company proposes an inflow charge based on the otherwise applicable consumption rate for the DG customer’s class. Notwithstanding this proposal, Company witness Miller cites in his testimony a report produced by the Brattle Group[40] (“Brattle

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[38] ICF, Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar (2018), available at: https://www.icf.com/insights/energy/value-solar-studies.
[39] *Id.* at App. A.
[40] The Brattle report cited by Company witnesses Miller and Aponte was provided as Company response to ELPC-CE-110 Att. 1.

report") that attempts to suggest that "the unit cost" of serving residential DG customers is between 20% and 50% greater than for non-DG customers. He notes that these "higher costs" may be a reflection "of the fact that more affluent customers with larger homes, and thus more electric load, have traditionally been the ones interested in installing DG."[41] Mr. Miller's assertion also appears to be at odds with the position taken by another Company witness, Mr. Eugène Breuring, who states that the Company does not separate the coincident and non-coincident peak demands of distributed generation customers in its peak demand forecast. However, even if the coincident and non-coincident peak demands of distributed energy customers could be separated, the impact of the distributed energy program would be modest since the program is not fully subscribed and is limited to one percent of coincident peak demand."[42]

Q. Is the Brattle report on the costs to serve residential DG customers a credible foundation and source of competent, material, and substantial evidence?

A. No. As JCEO witness Lucas details, the Brattle report, which is the only evidence offered by the Company on the costs to serve DG customers,[43] is deeply flawed in several respects, most notably as regards data problems underlying the report and the unreasonable statistical contortion used to create a set of numbers that suggest a higher "unit cost" of service. The Brattle report makes no assessment of the value or impacts of outflows from DG systems. Ironically, there is actually a more reasonable inference,

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[41] Miller at 27. Mr. Miller goes on to opine, without foundation, that "[a]lthough I suspect there is some truth to this, I do not believe it justifies have the Company's other customers subsidize DG ad infinitum."

[42] Company response to ELPC-CE-923.

[43] Company response to ELPC-CE-114. *See also* Company response to ELPC-CE-117, stating that "[t]he Company is beginning to explore the grid impacts of customers installing DG equipment in Michigan."

based on the evidence available in the Brattle report, strongly suggesting a lower cost of serving residential DG customers—by more than $130,000 in 2018 alone.

Q. Does the Brattle report evaluate the impacts on the grid—benefits or costs—associated with outflow energy from DG facilities?

A. No.[44]

Q. Is the Brattle report based on a costs of service study for customer-generators?

A. No. The Brattle report uses limited real plus estimated meter data as its foundation. Further, it uses adjusted allocation calculations from residential customers as a whole to estimate allocated costs for DG customers. So, while it is an analysis based on some real and estimated cost of service data, it is not a cost of service study.[45] Flaws with the data are detailed later in this testimony. That data set did not match the Company's most recent cost of service study, but the DG customer data was limited to 2018 (and estimated 2018) inflow data. To perform its work, Brattle could not rely on the Company's cost allocators, which were based on 2015-2017 data. Brattle used and made additional changes to an alternative allocation calculation based on a load study conducted by the Company in 2018. It is important to note that in deriving allocated costs from the "alternate" version of the Company's cost of service model, the Brattle report purports to evaluate costs for DG customers as a separate class, and, at the same time, calculates allocated costs for DG customers using allocators derived from residential customers as a whole.[46]

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[44] Exhibit CEO-25 (KRR-6) Company response to ELPC-CE-870.
[45] See Exhibit CEO-26 (KRR-7) Company response to ELPC-CE-888.
[46] Brattle report at 12-15.

Q. What were the underlying data problems with the data used in the Brattle report on residential DG customers?

A. First, it is important to note what a tiny fraction of residential customers on the Company's system are DG customers. The Brattle report shows that even at the end of 2018, the percentage of residential net metering customers is only 1/10th of 1 percent (0.001) of the total number of customers.[47] The estimated contribution of net metering customers to total sales for residential customers is even less, at 0.08% (0.0008).[48] And the net metering customers' contribution to class peak is less than 1/10 of 1 percent (0.00095).[49] To put this in perspective, the Company's annual variation in residential electricity sales from 2014 through 2018 ranges from 8.8 to 62.8 times the total amount of sales to residential net metering customers in 2018—on average 34 times greater.[50]

The Brattle report authors were honest in reporting that the data used as a foundation for their analysis was deeply flawed and incomplete.[51] The key data issues Brattle identified were:

- Many net metering customers were not customers for the full 2018 year. In fact, some of the data provided by the Company was for customers that did not even become net metering customers until 2019.
- Although there were about 1,700 residential net metering customers on the Company's system in 2018, hourly flow data that was essential for the analysis was

[47] Brattle report at 6.
[48] Brattle report at 14 (11.3 MWh out of 13,089.9 MWh).
[49] *Id.*
[50] Calculated using Residential net metering sales from Brattle report at p. 14 compared to figures for residential sales from Breuring-1-6 and WP-1-4.
[51] Brattle report at 4-5.

only available for about 1,300 of these customers. That is, data for about 24% of net metering customers was insufficient and disregarded.

- There are hours and days for every single net metering customer for which the Company provided no data at all.

Q. How did the Brattle report deal with these data problems?

A. After discarding much of the Company's data and choosing to use only data for customers that were net metering customers for the entire 2018 year, the Brattle report estimated the missing data for the remaining customers. In the words of the Brattle report, missing data was "filled-in and population-adjusted."[52]

Q. In your opinion, does the data foundation for the Brattle report provide a reasonable foundation for Company witness Miller's assertion that DG customers are more expensive to serve than non-DG customers?

A. No. The data is inadequate to support such an assertion. The flaws in the data underlying the Brattle report and the fact that it is the only data offered by the Company on costs of serving DG customers vis-à-vis non-DG customers[53] confirms that the Company has not submitted into the record in this case the data needed to support the design of DG tariff that will be just and reasonable for residential DG customers.

Q. Did the Brattle group reference the usage patterns of net metering customers *prior to* their installation of DG equipment?

[52] Brattle report at 5.
[53] *See* Exhibit CEO-29 (KRR-10) Company response to ELPC-CE-113.

A. No. The Brattle report did not have the pre-DG usage data for net metering customers, though doubtless this data was available to the Company and could have been used to confirm or deny Mr. Miller's earlier-cited suspicion. As a result, there is no way to determine whether the cost to serve the DG customer went up or down after the DG equipment was installed. Again, this data gap demonstrates that the Company's assertion that DG customers are more expensive to serve is unsubstantiated and unreasonable.

Q. What does the Brattle report information suggest about the usage patterns of the small sample of real and estimated net metering customer data used?

A. The graphs included in the Brattle report suggest, as far as the data will allow, that DG customers may actually create cost-saving benefits for the Company and other non-DG customers. For example, and subject to the caveat that these observations are based on the Brattle report's depiction of the data and estimates upon which it relied:[54]

- The graphic plot of energy use per customer shows that DG customers contribute significant beneficial load diversity as a result of decreased on-peak energy use and increased off-peak usage.[55]
- DG customers have lower coincident peaks than non-DG customers.[56]
- DG customers provide load diversity benefits through higher non-coincident peaks than non-DG customers.[57]

[54] It should be noted that the information in the Brattle report comparing DG and non-DG customer usage patterns is only illustrative of the differences and/or similarities in the load shapes of those groups. Within the non-DG population, there is certainly a great deal of diversity, and it is even likely that a number of non-DG customers have the same load shape as DG customers. Likewise, the Brattle report does not attempt to account for locational impacts, which may be significant.
[55] Brattle report at 8.
[56] *Id.* at 9.
[57] *Id.*

- While there is no obvious pattern connecting system peak, non-DG customer peak, and DG customer peak, it appears that DG customer peaks seldom align with system or residential class peaks. This means that DG customers provide additional load diversity benefits.[58]
- DG customers have a winter peak load shape that corresponds with that of non-DG customers, but with significant reductions leading up to the peak.[59]
- In the summer, DG customer have a peak that actually goes down as class system peak increases, and occurs later than the system peak, during cooler nighttime hours when system peak is beginning to fall off.[60]

In all, the Brattle report, even though founded on flawed and estimated data, paints a compelling picture of system- and class-wide benefits accruing in the cost to serve DG customers. It should be noted that Company witness Blumenstock responded to a request to document any and all monetary and non-monetary impacts that the Company has experienced to date as a result of interconnecting DG systems that "[a]s a result of interconnecting distributed generation systems, the Company has experienced, to date, impacts to the its distribution system including reduced loading on equipment, reduced electrical losses, and voltage support."[61] In general terms, this response seems to confirm the kinds of beneficial impacts suggest by the Brattle report analysis. This information should have led Company witness Miller to investigate, rather than wait and see, whether DG customers actually cost less to serve than non-DG customers. Whether the failure to

[58] *Id.* at 10.
[59] *Id.* at 11.
[60] *Id.*
[61] Company response to ELPC-CE-069. The Company has not conducted any modeling or other analysis to estimate the monetary impact estimates associated with these observed electrical impacts. Company response to ELPC-CE-890.

conduct that investigation and analysis was intentional or an oversight, in my opinion the result in this case is the same—the foundation for the Company's proposed DG inflow charge is inadequate. And because the flawed Brattle did not even purport to address outflows, the Company's proposed DG outflow charge is completely unsupported by evidence from the Company. In contrast, testimony by Mr. Kevin Lucas on behalf of the JCEO establishes that DG customers cost less to serve and create significant value to the Company and all its customers through energy exports.

Q. The Brattle report seems to suggest that DG customers may bring load diversity benefits to the Company grid. What do you mean by load diversity benefits?

A. Load diversity benefits are what make a networked electrical grid more efficient and less expensive than serving individual customers one by one, each with their own utility service. Utility capital and operating costs are heavily driven by peak use, and utility economics are therefore adversely impacted by low asset utilization factors. That is, major grid investments needed to meet peak demand are only used for relatively few hours in each year. Load diversity is the phenomena that not all customer usage and not even all usage in a single customer class is precisely uniform. Some residential customers work in offices during the day, some work at night. Diversity in load means that infrastructure usage can be spread across more hours of the day, week, month, and year, and that a system need not be built to serve all load at the same time. In addition, load diversity,by making load more evenly distributed, offers additional benefits in terms of distribution and transmission system infrastructure wear and tear and useful life—since the useful lives of those assets are most impacted by peak loads. Finally, when load diversity and distribution system asset utilization rates are flattened, infrastructure can be reconfigured for optimal performance and useful life, and replacement equipment can be smaller in size or capacity. In sum, an effective strategy for managing and reducing distribution infrastructure costs should involve optimizing load diversity to improve asset utilization rates followed by optimizing of the size and capacity of infrastructure. A utility focused on improving affordability, efficiency, and reliability should encourage, rather than discourage, DG deployment.

Q. Has the Company studied load diversity on its system?

A. The Company has not studied load diversity in any quantitative fashion on either its high or low voltage distribution systems.[62] As a result, the Company appears to lack the basic data needed to assess whether DG systems bring quantifiable load diversity benefits to the grid, either in specific locations or to the grid as a whole. In contrast, Ms. Claudine Y. Custodio submitted in testimony on behalf of the JCEO shows that DG customers do indeed contribute to load diversity.

Q. How, in the face of this evidence, does the Brattle report offer any support for Mr. Miller's assertion that residential DG customers are more costly to serve than non-DG customers?

A. Unfortunately, and disappointingly, Mr. Miller's assertion rests on statistical sleight of hand. After several adjustments and the application of non-DG allocators to costs and (real and estimated) DG customer consumption data (without regard for pre-DG usage patterns), the Brattle report calculates allocated costs for production and distribution for DG customers. Even if one assumes this allocation methodology, which is not detailed in

[62] Exhibit CEO-27 (KRR-8) Company response to AG-CE-304.

the Brattle report, is reasonable for estimating total allocated costs, the Brattle report then contrives a cost estimate for DG customers based on a "unitized allocated costs" calculation that is wholly unreasonable. The "unit cost" of service that Brattle calculated and upon which Company witness Miller relied was based on unitizing costs against coincident peak levels for production costs and non-coincident peak levels for distribution costs[63]—a contrived and wholly unreasonable basis for evaluating costs.

Q. Why do you say that unitization of production and distribution costs against coincident and non-coincident peak levels is unreasonable?

A. First, there remains a question of whether the measure used for unitization is reasonable. In this case, the coincident and non-coincident peak levels of the small sample of DG customer data used in the Brattle report is only meaningful when compared to the pre-DG peak levels for the evaluated customers. Brattle did not compare DG customer data to pre-DG peak levels. Second, the unitization against coincident and non-coincident peak levels produces bizarre and unreasonable results. "Unitization" means nothing more than dividing the costs by some unit—in this case, the Brattle report uses coincident and non-coincident peaks. To be useful, unitization calculations must generate some meaningful understanding of cost structures and vectors. In this case, the choice of coincident and non-coincident peak levels for DG customers produces bizarre results: If DG customers had a lower coincident or non-coincident peak demand, the "unitized allocated costs" would go up. While this is simple arithmetic, the consequence is that people like Mr. Miller would argue that as DG customers reduced their coincident or non-coincident

[63] This "unitization" of allocation costs against coincident and non-coincident peaks is what was necessary to produce numbers that showed higher costs for capacity costs, capacity-related cost offsets, and demand-related costs under the Brattle calculation. Brattle report at 15.

peak, they became more, not less, expensive to serve. As a corollary, the unitization method chosen in the Brattle report would suggest that as DG customers increased their coincident and non-coincident peaks, the cost to serve them would be lower. This result does not square with common sense, and therefore reinforces my conclusion that Mr. Miller's assertion that DG customers are more expensive to serve is unfounded and unreasonable.

Q. If unitization according to coincident and non-coincident peak is not appropriate, how should the Company and the Commission evaluate the data in the Brattle report?

A. First, the Commission and the Company should not seek to base any conclusions about the reasonableness of the Company's proposed DG tariff on the data underpinning the Brattle report. Second, to the extent that the estimation exercise in the Brattle report provides some basis for inference and informing further research, the logical method of "unitization" for estimating cost impacts of DG customers and the sales to those customers after installation of DG systems is a calculation of the costs per unit of energy sales. Of course, understanding the incremental impact of DG system operation also requires comparison with pre-DG consumption patterns.

Q. What does the Brattle report data show about allocated costs per unit of sales to DG customers?

A. The Brattle report provides the necessary data in its Appendix, in the table labeled "Residential Allocated Costs per kWh."[64] That data shows that the cost to serve the

[64] Brattle report at 29.

population of DG customers in 2018, based on the data extrapolation and estimation techniques employed by Brattle, was or would have been about $132,000 less than the cost to serve those customers as non-DG customers. That is, by using the Brattle report calculated allocated costs for DG and non-DG customers, and unitizing those costs by kWh sales, the result shows lower overall costs per kWh of sales to those customers—a lower cost to serve. The table below shows the calculation based on the Brattle report figures:

Table KR-1: Calculation of Estimated Over-Charging of NEM Customers, 2018

	Residential Allocated $/kWh Sales - Brattle		
Production	**non-NEM**	**NEM**	**Difference**
Net Capacity Cost	$ 0.041	$ 0.022	$ (0.019)
Capacity-Related Cost Offset	$ 0.021	$ 0.018	$ (0.004)
Non-Capacity-Related Cost	$ 0.043	$ 0.042	$ (0.001)
Total	**$ 0.105**	**$ 0.082**	**$ (0.024)**
Distribution			
Demand-Related Cost	$ 0.048	$ 0.058	$ 0.010
Customer-Related Cost	$ 0.011	$ 0.013	$ 0.002
Total	**$ 0.059**	**$ 0.071**	**$ 0.012**
		Estiimated Overcharging of NEM Customers	**$ 132,870.18**
Sales	13,089,908,238	11,335,089	

Q. Besides the Brattle report, has the Company made or caused to be conducted any study of the impacts of DG operations on the grid?

A. No. The Company has made no study of demands that residential distributed generators place on Company infrastructure beyond those required by Michigan's generator interconnection procedures for individual installations and does not study or calculate the impacts of distributed generation on the distribution system after interconnection projects are complete.[65]

Outflow Rate

Q. What rate does the Company propose for the "outflow" rate?

A. The Company proposes to pay its "embedded production rates"—which it defines as its power supply rates less any transmission or distribution costs, and to apply the credit for outflow only to offset the production section of the customer bill.[66]

Q. How does the Company justify the proposed inflow charge and outflow credit in the DG tariff?

A. Company witness Miller explains in his testimony how the inflow/outflow two-channel billing method works,[67] but offers no credible evidence demonstrating that either the inflow charge or the outflow credit is based on analysis of cost of service or value of exported energy. Mr. Miller implies that traditional net metering requires that non-generator customers subsidize customer-generators, but likewise provides no evidence to support the implied assertion.[68]

Q. How does the Company justify its proposal to credit outflows from DG facilities at the power supply less transmission rate and to only allow outflow credits to offset production charges?

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[65] Company responses to ELPC-CE-072, -077, -896.
[66] Miller at 23.
[67] *Id.* 22-23
[68] *Id.* at 23.

A. The Company rationale is based on three flawed elements. First, the Company argues that its proposed outflow credit is required under MCL 460.1177(4). Second, the Company asserts that MCL 460.1177(4) further excludes outflow credit for avoided transmission and delivery charges. Third, the Company asserts that MCL 460.1177(4) allows the Company to choose an outflow credit based on LMP or the power supply component of the class rate. In essence, the Company asserts that it is proposing what is required and authorized by Michigan law, citing only to MCL 460.1177(4).

Q. Is the Company's rationale consistent with the Commission's interpretation and application of the law and the broad authority granted to the Commission under MCL 460.6a(14)?

A. No. The Company rationale is at odds with the law, as the Commission has repeatedly explained. As a result, the Company's proposed rate for outflow credits is not prescribed by law. Rather, the Company should develop a value for outflow credits based on competent, material, and substantial evidence that demonstrates that the proposed rate is based on equitable cost of service.

Q. Did the Company evaluate any other DG tariff outflow compensation credit calculation methods besides LMP or power supply less transmission as part of developing its proposal in this case?

A. No.[69]

Q. Does the Company offer further justification for excluding from the outflow credit the value of avoided transmission costs?

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[69] Exhibit CEO-28 (KRR-9) Company response to ELPC-CE-865.

A. The Company asserts that "including transmission in the outflow credit would essentially compensate the homeowner with a private solar array for a service they are not providing, thereby increasing the energy bill of their neighbor."[70] It is not clear what the Company witness means about "a service" that DG customers are not providing. While DG customers do not provide transmission service, their reduced reliance on bulk electricity delivered through the Company's transmission and distribution system does reduce transmission costs, including marginal operating costs, line loss costs,[71] and, over the long term, the fixed capital costs of the system. To the extent that Company witness Miller is arguing that DG customers do not reduce current fixed transmission costs, he appears to be confusing sunk and fixed costs, as previously explained. To the extent that the Company is asserting that outflow credit for avoided transmission (or distribution) costs creates a cost shift to other customers who have not similarly reduced their usage, this argument must be backed by relevant facts. In order to determine whether other customers should bear the cost of un- or under-used infrastructure, regulators generally must first determine whether the costs were prudently incurred (i.e., not overbuilt) and whether the infrastructure remains used and useful in the provision of electric service such that the costs can and should be recovered from service users. Second, the regulator must determine whether the cost shift is material and significant in light of the many

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[70] Miller at 24.

[71] Line losses are known to increase during periods of peak demand, and therefore DG that reduces peak demand provides additional line loss benefits compared to the annual average. The Company does not have marginal line loss values and does not have the data to support calculation of marginal line losses. Company response to ELPC-CE-071. The Company is "expanding its modeling of the secondary distribution system and improving its capability of extracting data from those models," and "expanding its use of AMI smart meter data from secondary distribution customers," but is intended or likely to result in the Company having the data is needs to calculate or estimate marginal line losses. Company response to ELPC-CE-864. The Company "does not have an hourly model of its secondary distribution system that accurately reflects topology and hourly customer loads." Company response to ELPC-CE-891.

other ways in which actual usage differs from forecasted use. Finally, the regulatory authority must determine where and how to fairly allocate any costs it deems appropriate for recovery. This analysis must also include an assessment of whether the DG customer brought net benefits, above and beyond any cost shift impacts, to the grid and other customers as a whole through investment in and operation of the DG system. In other words, there are many questions that must be answered before the Company should be allowed to presume that denying fair credit for avoided transmission and distribution costs is the appropriate rate making remedy for what is only a potential cost shift in a future rate case.[72]

Q. Does the Company offer any other justifications for limiting the outflow credit to the production rate less transmission costs?

A. Yes. In response to a question from ELPC, Mr. Miller stated the Company's proposed DG outflow rate provides fair compensation for exported energy because "DG customers do not provide billing, customer service, or wires services as part of the excess power they put back on the grid, and so should not be compensated for these services."[73]

Q. Do you agree with this Company justification for a reduced outflow credit?

A. No. Billing, customer service, and wires services costs are already factored into cost of service-based rates in full, and those costs associated with exported energy are paid in full, according to the cost of service-based rates, by the customer that ultimately uses the exported energy. When exported energy leaves a customer-generator's premises, it serves

[72] Cost shifts cannot occur until the regulatory authority changes rates in response to a change in usage levels or other factors.
[73] Exhibit CEO-30 (KRR-11) Company response to ELPC-CE-115.

the nearest unserved load, relying upon only a fraction of the distribution system in so doing. On the way to serving that load, it passes through a Company revenue meter where it incurs a charge that appears on the served customer's bill—a charge based on the unitized and allocated costs of the entire distribution system. Reducing the DG customer outflow credit for these billed-for services forces the DG customer to subsidize the utility and is manifestly unfair.

Q. Does the Company offer any additional justification for proposing that DG customers should not receive credit for avoided transmission costs?

A. Company witness Miller offers only one additional justification, stating that "the literature generally suggests that increasing the penetration of solar on the grid increases the intra-day variations in load and may not notably affect the annual load peak of households."[74] Based on this purported "suggestion," Mr. Miller states that the Company believes it is not appropriate to include transmission (avoided costs) as part of the outflow credit at this time.

Q. Do you agree with Mr. Miller characterization of the study by Fischer, et al.?

A. No. Mr. Miller's citation to the study is misleading. The study is based on fairly advanced modeling of a dense cluster of homes—1,550 homes located in a city area of 1 square kilometer, with very high penetrations of several kinds of DERs, forecasted into the future. Contrary to Mr. Miller's description, the study assumes that PV systems are sub-optimally sized, as are customer-sited battery systems. The study finds that "efficiency gains in household devices, with annual energy savings of 28%, together with the

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[74] Miller at 25, referencing Fischer, D., Surmann, A., and Lindberg, K.; Impact of emerging technologies on the electricity load profile of residential areas; Energy and Buildings, 2020; Vol. 208.

introduction of local production from PV [solar], *compensate* for the additional electricity demand."[75] The study further identifies heat pumps and electric vehicles as primary drivers of load variability, not solar, and concludes, quite reasonably, that "[i]n a future facing increased electrification of the energy system, careful design of control strategies is therefore recommended."[76] These findings and the conclusion are almost completely inconsistent with the way Mr. Miller described the research. The study Mr. Miller cites cannot be used to support his conclusion that transmission offset credits should not be part of the outflow credit. Mr. Miller cites no other literature in his testimony to support his assertions.

Q. What do you conclude regarding the Company's position, espoused by Mr. Miller, that DG customers do not provide benefits to the grid and do not cost less to serve?

A. Company witness Miller is decidedly hostile to customer-generators and even to analysis that would answer fundamental questions about the costs and benefits of DG. He chooses to believe that net metering forces non-DG customers to subsidize DG customers based solely on two generalized, biased, and flawed studies, and on the statistical trick of unitizing estimated allocated costs in the Brattle report against peak levels, as previously discussed in this testimony.

Q. Please discuss the issues you have with the two studies cited by Company witness Miller as supporting the existence of subsidies to net metering customers.

A. The two studies cited by Mr. Miller were referenced in the Company's response to ELPC-CE-116. The first, which Mr. Miller cites as "Sergici, et al. (2019)," is actually

[75] Fischer at 10. Emphasis added.
[76] *Id.*

written entirely by Brattle Group employees and continues the dubious approach of classifying all revenue decreases from net metering as a cost of net metering.[77] The lead author does not disclose her twelve-year tenure with the Brattle Group as part of her biography in the article. The article does not actually evaluate any data from the Company, nor did it use actual cost of service data for the utilities for which it presented results. The second study relied upon by Mr. Miller is an advocacy piece titled "Incentivizing Solar Energy: An In-Depth Analysis of U.S. Solar Incentives," and was published by the Consumer Energy Alliance ("CEA"), a front group for the energy industry with an aggressive pro-fossil energy agenda.[78] Contrary to the study's title, the CEA report only addresses residential rooftop solar and claims to quantify all "incentives" that net metering customers are alleged to enjoy. Similar to the Brattle article, the CEA document treats all customer bill savings created through self-generation as an "incentive" and rests its findings on highly generalized and estimated calculations. Also like the Brattle article, the CEA report does not rest its conclusions on actual data from the Company.

Q. Is the Company consistent in its assertions regarding the costs and benefits of DG?

A. Although the Company expresses some ambiguity about whether DG customers have a positive, negative, or neutral impact on the grid,[79] Company witness Miller repeatedly

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[77] Sergici, S., Yang, Y., Castener, M., Faruqui, A., *Quantifying Net Energy Metering Subsidies*, Electricity Journal 32 (2019). Attachment 1 to ELPC-CE-116.

[78] *See* SourceWatch, *Consumer Energy Alliance*, Center for Media and Democracy (2011, and updated), available at: https://www.sourcewatch.org/index.php/Consumer_Energy_Alliance.

[79] *See* Company response to ELPC-CE-117. Company witness Miller, when asked whether he was "aware of any benefits that excess power from DG customers can provide to the grid" and to "describe all efforts [he] has made to analyze and compensate such benefits," replied that "I'm aware of a continuing debate about whether or not DG customers have a positive (benefit), negative (added costs), or neutral impact on the grid. . . . The Company is just beginning to explore the grid impacts of customers installing DG equipment in Michigan." *Id.*

and consistently asserts that net metering and volumetric rates subsidize customers that reduce their use of the grid.[80] The other way in which the Company is consistent is in making its assertions without the benefit of data, research, or analysis. The Company appears to have failed to analyze available data on DG customers and their energy usage patterns, both before and after installing of DG. This is exemplified by my prior discussion in this testimony regarding the Brattle report on residential DG usage. The Company has not studied DG penetration values at the substation or circuit level.[81] In addition, the Company not yet studied even the most basic aspects of grid and revenue impacts by DG customers, such as DG impacts on marginal line losses[82] (though the Company acknowledges the fact that lines losses increase with demand[83]), distribution system impacts,[84] demands on distribution infrastructure,[85] the opportunity for DG and other DERs to offer non-wires solutions benefits in lieu of capacity upgrade requirements,[86] analysis of load diversity on the high or low voltage distribution systems,[87] how excess power from DG facilities is used in the grid,[88] the impacts of the proposed DG tariff changes,[89] or the impacts of recognizing transmission benefits for outflow energy.[90] The Company appears to recognize these shortcomings, stating that "it

[80] *See* Company responses to ELPC-CE-241, 242, 243, 244, 247.
[81] Company response to ELPC-CE-911.
[82] Company response to ELPC-CE-071.
[83] Company response to ELPC-CE-920.
[84] Company response to ELPC-CE-069, 077.
[85] Company response to ELPC-CE-072.
[86] Company response to ELPC-CE-129.
[87] Company response to AG-CE-304.
[88] Company response to ELPC-CE-119.
[89] Company response to ELPC-CE-079.
[90] Company response to ELPC-CE-120.

would be premature to assign costs, or benefits, to DG customers before the Company has had an opportunity to properly gather and evaluate the impacts on the grid."[91]

Q: Have you reached any conclusions based on the Company's inconsistent statements?

A: The Company's conclusion that it is premature to assign costs or benefits to DG without actually evaluating DG impacts on the grid is reasonable and stands in contrast to the other, poorly founded conclusions reached by the Company. On the basis of the Company's own assertions regarding its inability to properly assign costs or benefits to DG customers, the Commission should not approve the Company's proposed DG Tariff. In the end, Mr. Miller's anti-DG and net metering assertions on behalf of the Company are unfounded, inconsistent, and contradicted, by both his discovery responses and his characterization of the studies he cites. An honest, transparent, and comprehensive analysis of the costs and benefits of DG operations is essential because only by analyzing both the costs and benefits of DG can the Company quantify the full value of DG. The Commission must require Consumers to determine this value before the Commission approves a DGTariff for the Company's service territory and customers.

Q. Should the Commission approve the Company's proposed DG tariff in light of these evidentiary and analytical deficiencies?

A. No. The lack of evidence establishes that it is premature to draw any conclusion about system impacts on costs of service from DG operations other than that further study is required. Therefore, the risk of unfair discrimination through rate design on DG

[91] Company response to ELPC-CE-117.

customers, and the risk of unintended impacts on distributed energy resources ("DER") market growth in general, is significant.

Q. What kind of analytical foundation should the Commission require of the Company in order to meet its burden of proposing an equitable DG tariff that is based on actual cost of service?

A. The Commission should require a detailed Value of Solar analysis that includes the impacts of outflow energy. As previously discussed in this testimony, there are numerous examples and consultants available to help guide the Company in doing the work it must to provide a cost-based foundation for its DG Tariff proposal. The table below, taken from the ICF meta-analysis previously discussed,[92] provides a listing of the potential costs and benefits of DG operations and the number of studies that included assessment of those impacts:

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[92] *See supra note 38.*

Table KR-2: Costs and Benefits Addressed in Value of Solar Studies

Value Category		Benefit (+) or Cost (-)	Number of Studies Addressing this Category
Utility System Impacts			
G	Avoided Energy Generation	+	15
G	Avoided Generation Capacity	+	15
G	Avoided Environmental Compliance	+	10
G	Fuel Hedging	+	9
G	Market Price Response	+	6
G	Ancillary Services	+/-	8
T	Avoided Transmission Capacity	+	15
T	Avoided Line Losses	+	11
D	Avoided Distribution Capacity	+	14
D	Avoided Resiliency & Reliability	+	5
D	Distribution O&M	+/-	4
D	Distribution Voltage and Power Quality	+/-	6
C	Integration Costs	-	13
C	Lost Utility Revenues	-	7
C	Program and Administrative Costs	-	7
Societal Impacts			
S	Avoided Cost of Carbon	+	8
S	Other Avoided Environmental Costs	+	9
S	Local Economic Benefit	+	3

These impacts should be objectively assessed by the Company as part of a Value of Solar study prior to proposing a DG Tariff that could cause irreparable harm to DG customers and the market for DG in the Company's service territory.

Q. In your opinion, what is the likely outcome of an objective and comprehensive assessment of the benefits and costs of the operation of DG systems?

A. If the Company were to conduct an objective and comprehensive assessment, I think two outcomes are likely: First, the Commission and the Company would see greater confidence in the decision making and rate setting processes associated with establishing just and reasonable rates for DG customers. The testimony of Dr. Gabriel Chan offers insight and experience from Minnesota's experience with the Value of Solar approach that serves as a useful reference point. Second, such an analysis would most likely confirm the empirical analysis conducted by Mr. Kevin Lucas showing that the net value of DG exports exceeds the otherwise applicable full retail rate. This has been the experience in the majority of value of solar studies conducted across the U.S.,[93] and I see no reason to expect a different result in the Company's service territory. The lesson of such a study is that even under full retail net metering, DG customers are most likely subsidizing the Company and other customers.

Q. In light of your testimony, what action do you recommend that the Commission take on the Company's DG tariff proposal?

A. My testimony and the testimony of Mr. Kevin Lucas, on behalf of the JCEO, establishes two key evidentiary facts relating to the Company's proposed DG Tariff. First, the Company's sole basis for its proposed DG Tariff are the fatally flawed report from the Brattle Group and an erroneous interpretation of Michigan law. As a result, in my opinion the Company has not provided a competent evidentiary basis for its proposal that is based on cost of service. Second, Mr. Lucas' analysis, based on Company cost of service data and more reasonable and credible analysis establishes both that DG customers are less expensive to serve, and that their outflow energy, on average, is worth much more to the utility and other customers than even a full retail rate credit. Based on my analysis of this evidence from the Company, and from the perspective of administrative justice, DG customers should not be punished for the Company's failure to collect the data and perform the analysis necessary to support an equitable cost of service-based DG tariff.

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[93] G. Weissman, E. Searson, R. Sargent, *The True Value of Solar: Measuring the Benefits of Rooftop Solar*, Environment America (Jul. 2019) at 10. Available at: https://environmentamerica.org/sites/environment/files/resources/AME%20Rooftop%20Solar%20Jul19%20web.pdf

The Commission should reject the Company's proposed DG tariff and approve an interim DG Tariff in-line with Mr. Lucas' testimony. This interim DG Tariff can be replaced after the Company has conducted a Value of Solar analysis to inform its proposals.

Q. If the Commission accepts your recommendations, isn't there a risk that DG customers will be overpaid under the interim DG tariff you propose?

A. There is no reasonable likelihood of overpayment under the interim tariff that I recommend. The testimony of Mr. Kevin Lucas on behalf of the JCEO establishes that net metering customers both have reduced cost to serve and generate outflows that have value exceeding the average retail rate otherwise applicable for consumption—and this is the only reliable evidence based on the Company's cost of service in the record. Further, given the extensive body of valuation studies that have found net benefits even under full, traditional net metering, the risk of overpayment for exported energy from DG facilities even at a full retail credit rate is very small. In light of the very small market for DG in Michigan today, the total magnitude of outflow credits, even with a credit for reduced inflow cost of service, would likewise be small. Perhaps more importantly and from an administrative justice perspective, setting the interim rate at the level established by Mr. Lucas in his testimony, and in any event at a level no lower than the full amount of the Company's production, transmission, and delivery costs will motivate the Company to complete the analysis and not punish potential DG customers for the Company's failure to substantiate its proposals in this case. In the unlikely worst case, Michigan will be home to a few more locally constructed, non-polluting renewable energy generating systems while the Commission awaits the development by the Company of cost of service-based rate proposals.

Q. Do you think further evaluation of the establishment of a separate rate class for net metering customers is appropriate?

A. A fairly conducted study of the costs to serve net metering customers and the value of their generation outflows justifies significant credits to those customers but does not require the establishment of a separate rate class. A separate rate class is not required to fairly compensate DG customers. Fair compensation credit for DG customers, including a credit for reduced cost of service, can be accomplished through a just and reasonable DG Tariff that incorporates the values resulting from Mr. Lucas' analysis of Company cost of service data. A separate rate class is not justified based on material differences in usage patterns between DG and non-DG customers. Analysis by Ms. Claudine Y. Custodio submitted in testimony on behalf of the JCEO shows that DG customer usage patterns fall within the general range of customer usage. DG customers use and are connected to the same distribution grid infrastructure as non-DG customers. That means DG customers provide diversity benefits within the existing distribution system grid. Experience with other rate designs, such as voluntary time of use rates and demand-response program rates, demonstrates that an approach of base rates with adders and/or charges is effective and administratively simple.

IV. SUMMARY OF RECOMMENDATIONS

Q. Please summarize your recommendations to the Commission.

A. Based on my review of the evidence in this proceeding and the findings and conclusions that I have reached, I make the following specific recommendations to the Commission:

- **First**, the Commission should reject the Company's proposed DG tariff in its entirety.
- **Second**, the Commission should approve an interim DG tariff that sets the inflow charge at the consumption rate otherwise applicable usage rate and that sets an outflow credit at $0.23957 per kWh plus an adder for reduced cost of service, as

recommended in Mr. Kevin Lucas' testimony. In no event should the Commission approve an interim outflow credit that is set any lower than the full amount of the Company's production, transmission, and delivery costs.

- **Third**, the Commission should direct the Staff to lead stakeholders in developing a framework for a comprehensive Value of Solar analysis for Michigan. The inconsistency in DG tariff structures in Michigan is inimical to the formation and maturation of self-sustaining markets for non-utility distributed renewable energy generation. In this regard, I urge the Commission to accept the recommendations of Dr. Gabriel Chan on behalf of the JCEO setting forth the benefits of a consistent and equitable valuation framework based on experience gained in Minnesota. This process should include quantification of environmental impacts in order to facilitate Commisison review of utility proposals under MEPA.
- **Fourth**, the Commission should order the Company to evaluate the costs and benefits of DG deployment and operations in its service territory, using the framework developed as discussed in the previous recommendation, and as discussed by Staff in Appendix E to its February 2018 report to the Commission.[94] The valuation should at a minimum include quantification of the value of DG operations relating to: energy and capacity, transmission and distribution, transmission and distribution loss savings, reactive power support, environmental benefits, and other benefits, such as hedge value.[1] As discussed by Dr. Chan, the study should provide substantial and meaningful opportunity for stakeholder engagement and full transparency in data and calculations used in conducting the study.

Q. Does this conclude your testimony?

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[94] MPSC Staff, *Report on the MPSC Staff Study to Develop a Cost of Service-Based Distributed Generation Program Tariff,* App. E (Feb. 21, 2018).

A. Yes.

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the Application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief.	)))))	Case No. U-20697

DIRECT TESTIMONY OF
RONNY SANDOVAL

ON BEHALF OF

THE ECOLOGY CENTER, THE ENVIRONMENTAL LAW & POLICY CENTER, THE GREAT LAKES RENEWABLE ENERGY ASSOCIATION, THE SOLAR ENERGY INDUSTRIES ASSOCIATION, AND VOTE SOLAR

June 24, 2020

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I. INTRODUCTION AND WITNESS QUALIFICATIONS

Q. Please state your name and qualifications.

A. My name is Ronny Sandoval. I am President of ROS Energy Strategies, LLC, a Colorado based limited liability company specializing in energy consulting. My business address is 1905 15th St. #7241 Boulder, CO 80306.

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

A. I am testifying on behalf of the Environmental Law & Policy Center, the Ecology Center, the Solar Energy Industries Association, Vote Solar and the Great Lakes Renewable Energy Association (collectively, "Joint Clean Energy Organizations" or "JCEO").

Q. Please provide your educational background.

A. I hold a Bachelor of Science degree in Mathematics from New York University, a Bachelor of Engineering in Electrical Engineering from Stevens Institute of Technology, and a Master of Business Administration from New York University.

Q. Please describe your work and professional experience.

A. I have over ten years of management experience in the utility business, including areas of transmission and distribution system planning and demand-side management. In my more recent roles in the non-profit advocacy space, I developed strategies to modernize and increase the efficiency of the electric grid across various state proceedings and forums, through cost-effective system investments, greater adoption of intelligent system operations, and transparency through metric reporting and stakeholder engagement.

I sit on the board of GridWise Alliance, an organization that champions the transformation of the electric grid by leveraging its diverse membership to support key decision makers through the development of strategies, action plans, best practices, education, outreach and more. I also sit on the board of Interestate Renewable Energy

Council, a non-profit organization that focuses on building the foundation for a clean energy economy, by providing leadership and expertise across areas of regulatory reform, workforce development, and customer empowerment. Finally, I am a member GridLab's team of experts – proving technical assistance across regulatory proceedings, technical reports, and other forums. My work experience is summarized in my resume, Exhibit CEO-31 (RS-1) to my testimony.

Q. Have you previously filed expert testimony in a proceeding before the Michigan Public Service Commission?

A. No. However, I have previously testified in utility proceedings before regulatory commissions in other states, including the following cases:

- Case No. CEPR-AP-2018-0001 Review of the Puerto Rico Electric Power Authority Integrated Resource Plan;
- Cause No. 45264 Verified Petition of Indianapolis Power & Light Company for Approval of IPL's TDSIC Plan for Eligible Transmission, Distribution, and Storage System Improvements;
- Docket No. ER16060524 In the Matter of Rockland Electric Company for Approval of an Advanced Metering Program; and for Other Relief
- Cause No. 44720 Duke Energy Indiana, Inc.'s verified petition for approval of its 7-year plan for eligible Transmission, Distribution, and Storage System Improvements.

Q. Are you providing any exhibits to your testimony?

A. Yes.

- CEO-31 (RS-1), which is a copy of my resume.
- CEO-32 (RS-2), which is a report from Gridlab and IREC on the goals and principles of grid modernization. Sara Baldwin, Ric O'Connell, Curt Volkmann. A Playbook for

Modernizing the Distribution Grid; Volume I: Grid Modernization Goals, Principles and Plan Evaluation Checklist. IREC and GridLab. May 2020. https://irecusa.org/publications/ and https://gridlab.org/publications/.

- CEO-33 (RS-3), a report from the National Renewable Energy Laboratory (NREL) on the lessons learned from utility-led distributed energy resource aggregation in the U.S. Cook, Jeffrey J., Kristen Ardani, Eric O'Shaughnessy, Brittany Smith, and Robert Margolis. 2018. Expanding PV Value: Lessons Learned from Utility-led Distributed Energy Resource Aggregation in the United States. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71984. https://www.nrel.gov/docs/fy19osti/71984.pdf.
- CEO-34 (RS-4), a presentation to the Oregon Public Utility Commission from the Lawrence Berkeley National Laboratory (LBNL) Distribution Planning Regulatory practices across states. Schwartz, Lisa. 2020. https://www.oregon.gov/puc/utilities/Documents/DSP-Schwartz-Presentation.pdf

II. SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Are you familiar with the Company's application?

A. Yes.

Q. Please summarize the materials that you reviewed in preparing your testimony.

A. I reviewed the Company's application, including testimony and exhibits filed in support of its application. I have also reviewed the Company's responses to discovery requests.

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

A. I address the value of distributed generation to the distribution grid and discuss how the Company's proposed Distributed Generation Tariff should take into account the impact of distributed generation. I discuss the valuation of deferred distribution investments, and propose ways in which the Company could consider how to maximize distribution benefits by properly valuing DG. I also discuss the relationship between the Company's distribution planning process and the Company's DG Tariff, and consider how distribution planning, grid modernization, and compensation for distributed energy resources (DERs) can interact to optimize grid operation and design. Finally, I address specific components of the Company's broader grid modernization strategy—its proposed battery storage pilots, Distributed Energy Resource Management System (DERMS), and investment in Conservation Voltage Reduction (CVR).

Q. Please summarize your reactions to the Company's application.

The Company entirely ignores the value of distributed generation on the distribution grid. In fact, the Company's position is based on the premise that distributed generation provides no value to the distribution grid. Not only does this call into question whether the Company's DG Tariff is cost-based, it also hinders the Company's grid modernization and distribution planning efforts going forward. With respect to certain specific distribution system investments that the Company proposes in this proceeding—in particular: storage pilots, a Distributed Energy Resources Management System (DERMS), and Conservation Voltage Reduction (CVR)—I commend the Company's willingness to consider projects that can enhance its distribution grid, but I also have some suggestions for the Company for improving the proposed projects. While I do not comment on every issue raised in the proposal, my silence on any issue does not constitute an endorsement of or agreement with Company's position on that issue.

Q. Please summarize your recommendations to the Commission in this proceeding.

A. Broadly, my testimony in this proceeding recommends that the Company better leverage distributed generation and other DER as a key tool in its distribution planning and grid modernization strategy going forward, because distributed generation and other DER can provide value to the grid. Specifically, I recommend that the Commission:

- Direct the Company to include, as a part of its compensation to DG customers, compensation for the value of distributed generation to the grid;
- Further investigate the value of distributed generation to the grid as a part of the Value of Solar study that JCEO witnesses Rabago and Chan describe in more detail;
- Direct the Company to investigate IDP—including its several components which I have described in my testimony—through the long-term stakeholder-informed distribution planning process being carried out in Docket No. U-20147;
- Direct the Company, in future applications in which the Company proposes pilots, to clearly articulate intended outcomes from those pilot proposals, and clearly articulate a path for the pilot to lead to large-scale deployment;
- Disallow the Company's proposed expenditures related to DERMS, and;
- Direct the Company to file periodic reports with the Commission including metrics detailing the level of voltage reductions, loss reductions, service quality issues encountered, energy savings, demand reductions, and greenhouse gas emission reductions that can be attributed to the performance of its CVR deployments.

Q. Please explain how your testimony is organized.

A. First, I discuss how the Company plans its distribution grid, and evaluate the Company's consideration of distributed generation and other distributed energy resources as a part of that planning process.

Then, I evaluate how the Company's plan to *modernize* its grid takes into account distributed generation and other distributed energy resources.

Next, I specifically address the Company's Distributed Generation Tariff, and explain why the Company's failure to evaluate the value of distributed generation to the distribution grid not only calls into question whether the Company's DG Tariff is cost-based, it also hinders the Company's grid modernization and distribution planning efforts going forward.

Finally, I focus on specific distribution system investments (storage pilots, a Distributed Energy Resource Management System or DERMS, and conservation voltage reduction or CVR) that the Company proposes in this proceeding, and offer ways in which the Company might strengthen those proposed investments.

III. DISTRIBUTION SYSTEM PLANNING

Q. Please summarize the Company's proposed investments in its distribution system.

A. The Company is proposing to invest over $720 million in capital projects and over $254 million in operation and maintenance (O&M) across its distribution system[1] through this rate case filing. The Company states its investments in this case are aimed at improving system reliability, advancing the benefits articulated in its Integrated Resource Plan (IRP) such as ending coal use by 2040, and expanding reliance on demand-side resources that will help keep customer energy costs affordable.

Q. How does the Company prioritize its distribution system investments?

A. The Company identifies a number of guiding principles it uses to prioritize its investments. These include:

[1] Direct Testimony of Richard T. Blumenstock on behalf of Consumers Energy Company, February 2020, Case No. U-20697, page 7, line 4.

- The Company's "triple bottom line"[2] approach – which seeks to balance the interest of customers, stakeholders, and society by measuring success on "people, the planet, and prosperity".
- The Company's "clean and lean"[3] approach – which moves towards "cleaner more modular generation resources" to keep customer bills affordable.
- The Company's strategy of "excelling at the basics and building for the future"[4] – which includes making investments in core traditional infrastructure and modernizing the electric grid.

The Company also states that it prioritizes investments to achieve five long-term objectives[5]:

- Enhance cybersecurity, physical security, and safety;
- Improve reliability and resilience;
- Optimize system cost over the long term;
- Increase sustainability and reduce waste in the system, and;
- Enable greater control.

Though these principles are sound, the details and associated implementation matter. Ensuring the Company's internal priorities are aligned with the prime concerns of energy stakeholders across the State is essential. I'll discuss this alignment further through my observations of the Company's grid modernization strategy.

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[2] Direct Testimony of Michael A. Torrey on behalf of Consumers Energy Company, February 2020, Case No. U-20697, page 6, line 10.
[3] Direct Testimony of Michael A. Torrey on behalf of Consumers Energy Company, February 2020, Case No. U-20697, page 16, line 20.
[4] Direct Testimony of Richard T. Blumenstock on behalf of Consumers Energy Company, February 2020, Case No. U-20697, page 5, line 11.
[5] Direct Testimony of Richard T. Blumenstock on behalf of Consumers Energy Company, February 2020, Case No. U-20697, page 12, line 4.

Q. Does the Company identify a long-term plan for its distribution system?

Yes. In order to execute on its stated priorities, the Company has developed two foundational plans underpinning its electric strategy of "excelling at the basics and building for the future" and pursuing its "clean and lean" approach.

The first is the Company's Electric Distribution Infrastructure Investment Plan (EDIIP) which was developed in March 2018 following a Commission Order in the Company's Rate Case, under Case No. U-17990, with the goal of enhancing transparency and visibility into the electric distribution planning process.

The second is the Company's IRP, which was filed and approved in Case No. U-20165, and establishes the Company's long-term Clean Energy Plan (including investments in solar generation and energy efficiency).

The Company states that additional capital investments and maintenance spending, above and beyond the "starting points" in the EDIIP and IRP, are necessary to maintain and improve reliability of its electric distribution system. Specifically, the Company explains that in this rate case it is proposing to invest larger amounts in its "New Business, Asset Relocations and Reliability" sub-program areas beyond the investment levels the Company identified in its 2018 EDIIP to address asset deterioration, public and employee safety, improve efficiency and reliability, and facilitate the interconnection of Distributed Energy Resources (DERs).

Q. Are there other planning efforts underway with implications for the Company's distribution system?

Yes. Following the Company's EDIIP filing, the Commission created a dedicated docket under Case No. U-20147 to encourage stakeholder engagement and to serve as a repository for future distribution plans. Comment opportunities and workshops associated with this docket have allowed diverse stakeholders to communicate their respective priorities on what electric companies should consider including in future distribution system plans. As part of this Electric Distribution Planning process, stakeholders have advanced considerations across emerging planning areas, such as developing a value for resilience. In addition, the Commission has encouraged the examination of dynamic load forecasting, hosting capacity analyses, non-wires alternatives, benefit costs analyses and other planning considerations that are at the core of an Integrated Distribution Planning framework.

Q. What is Integrated Distribution Planning?

A. Integrated Distribution Planning ("IDP") is an evolution in utilities' traditional distribution grid planning processes. Historically, distribution planning has involved the identification of investments needed to deliver electricity from a small number of large power plants. Under the traditional paradigm where power flows one-way from the utility to the customer, this process was fairly straightforward. Distribution investments were primarily determined through the use of load forecasts based on the historical demand and a mix of traditional utility projects, evaluated within a specified planning horizon. Importantly, this planning process for the most part has traditionally been carried out in within utility companies and outside of the view of energy stakeholders.

However, with the recent growth of distributed energy resources (DERs), customer demand has become increasingly dynamic. Investments in traditional distribution infrastructure such as transformers and substations can longer be viewed as inevitable, especially as distributed energy resources and non-wires solutions demonstrate they can be used to meet certain energy needs more efficiently. Additionally, it has become clear that the ability to advance policy priorities such as increased resiliency, decarbonization, and greater demand flexibility (which can help achieve greater utilization from the distribution assets we already have) depends not only on large scale resources that may identified in an IRP, but also on DERs identified through a transparent, inclusive stakeholder distribution planning process.

Q. Please define the term Distributed Energy Resources.

Definitions for Distributed Energy Resources can vary based on jurisdiction, regional policy objectives, etc. The National Association of Regulatory Utility Commissioners (NARUC) offers that a "DER is a resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load. Examples of different types of DER include solar photovoltaic (PV), wind, combined heat and power (CHP), energy storage, demand response (DR), electric vehicles (EVs), microgrids, and energy efficiency (EE)".[6] An important aspect of this definition is that it views DERs as a "resource" (not just a "source") that can be leveraged to supply a broad range of meaningful energy services to the grid, and can be much more than a system condition that needs to be managed.

Q. How do utilities and their customers benefit from IDP?

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[6] NARUC Manual on Distributed Energy Resources Rate Design and Compensation Prepared by the Staff Subcommittee on Rate Design. 2016 https://pubs.naruc.org/pub.cfm?id=19fdf48b-aa57-5160-dba1-be2e9c2f7ea0

A. Utilities and their customers can derive substantial benefits from transitioning to IDP, including:

- lowering costs to reduce rate pressure in a low load growth environment;
- enhancing the efficiency of existing assets and processes;
- creating more cost-effective programs with better returns for customers and shareholders;
- identifying new capabilities required to better align operations with changing customer expectations; and
- preparing a grid that supports and is better adapted to increasing deployment of distributed energy resources.

GridLab's IDP Report[7] (Exhibit CEO-32 to my testimony) presents a framework developed through an assessment of grid modernization and distribution planning activities across various states.

Q. Please describe the components of an IDP framework.

A. The IDP framework identifies five essential capabilities needed to ensure utilities and their customers get the most out of investments in grid modernization and the products and services that may be developed as a result of these investments.[8]

Specifically, these capabilities include:

(1) Advanced Forecasting and System Modeling

(2) Hosting Capacity Analysis

[7] Curt Volkmann. Integrated Distribution Planning A Path Forward. GridLab. 2019. http://gridlab.org/wp-content/uploads/2019/04/IDPWhitepaper_GridLab-1.pdf

(3) Disclosure of Grid Needs and Locational Value

(4) New Solution Acquisition

(5) Meaningful Stakeholder Engagement

An IDP framework can provide a long-term, cohesive, and transparent view of utility distribution system investment decisions, including on demonstration projects and pilots, before proposals appear in a rate case. For instance, the Commission's recent "Michigan Statewide Energy Assessment Final Report" offered recommendations that urged better alignment between distribution plans and integrated resource plans, consideration for the value of fuel security and diversity of resources, and consideration for the value of resilience in future investment decisions related to energy infrastructure in future cases[9]. IDP can create a forum where separate, associated efforts and planned investments related to distribution planning on demand response, sourcing of resources, and resilience and other priorities are harmonized. This is essential to ensuring desired policy objectives are effectively pursued while minimizing the potential for uncoordinated efforts and gaps in planning and implementation.

Though the Commission has initiated a stakeholder process on distribution planning through MI Power Grid "designed to maximize the benefits of the transition to clean, distributed energy resources for Michigan residents and businesses"[10], the effort is still underway. It is anticipated the Commission will issue guidance to Michigan utilities based on Staff's recent Electric Distribution Planning Stakeholder Process report on

[9] Michigan Statewide Energy Assessment Final Report; Michigan Public Service Commission; September 11, 2019 https://www.michigan.gov/documents/mpsc/2019-09-11_SEA_Final_Report_with_Appendices_665546_7.pdf
[10] MI Power Grid – Electric Distribution Planning Stakeholder Process; MPSC Staff Report; April 1, 2020 https://www.michigan.gov/documents/mpsc_old/Distribution_Planning_Report_Final_685525_7.pdf

future distribution plans. This report summarized stakeholder input and provided recommendations from Staff. The Company's current filing however was made before this direction could be issued, and is thus not able to benefit from this guidance. The Company's current proposal includes commitments on distribution planning, grid modernization, and the role of DERs that could differ from the direction that is ultimately adopted as part of a stakeholder distribution planning process, so it should proceed with caution to ensure it is on a path of least regret.

Q. Does transitioning to IDP require that a utility implement all five "capabilities" in the IDP framework immediately?

A. No. To some extent, utilities may pursue each of these capabilities independent of each other. However, utilities can maximize the value of these capabilities when they work in concert. Meaningful stakeholder engagement is key to any IDP process, and ensures investments, programs, and operations align with the need of customers and others that may be impacted. Acquiring new solutions to systems constraints is more effective when there is more transparency on the nature of a specific need and the value of meeting that need. Similarly, advanced forecasting and system modeling that considers distributed energy resources ("DER") allows energy service companies to have forward-looking information about the market. When incorporated into a hosting capacity analysis, this information becomes more actionable to developers than only having information on the present status of the grid.

Q. Does the IDP framework prescribe specific technologies or solutions?

A. No. The goal of the framework is not to be prescriptive in recommending specific technologies or solutions, but rather to provide a foundation for utilities, customers, and other energy stakeholders to develop a common understanding of the essential capabilities that arise from grid modernization investments and integrated distribution planning practices. This process also facilitates discovery amongst stakeholders of the prioritization and weight that should be assigned to each IDP capability based on the objectives of the collaborative. In addition, all investments that impact the distribution system—whether for reliability, resiliency, modernization, capacity, or efficiency are provided a dedicated forum where cross-impacts and synergies can be identified and understood.

Q. Why is IDP relevant to the Company's application in this proceeding?

A. In its application, the Company describes both its proposed compensation for customers with distributed generation (its proposed DG Tariff), as well as its proposed approach to accommodating increasing penetrations of distributed generation and DER on the grid. By implementing IDP, the Company can help ensure that it is planning its distribution grid in a manner that leverages the value of distributed generation and other DER. If the Company were to implement IDP, it would replace the current paradigm of approaching distribution planning as a process that reacts primarily to system shortfalls, with an approach that provides the Company the tools necessary to proactively pursue the capabilities stakeholders would like to see from their energy system—including enhanced resiliency, expanded options for customer products and services, and additional tools for decarbonization. Moreover, IDP can help the Company better evaluate the value of distributed generation and other DER to the grid, which can inform a "Value of Solar" approach to compensating distributed generation (as discussed by JCEO witnesses Chan and Rabago).

Q. What do you recommend to the Commission with respect to the Company's distribution planning process?

A. I recommend the Commission direct the Company to investigate IDP—including its several components which I have described in my testimony—through the long-term stakeholder-informed distribution planning process being carried out in Docket No. U-20147.

IV. GRID MODERNIZATION STRATEGY

Q. What is your understanding of the Company's grid modernization strategy?

A. The Company is focused on building three primary advanced grid capabilities over the next five years, namely: reliability and resilience; system efficiency and optimization; and DER integration. This would be achieved through investments in core traditional infrastructure and modernization of the electric grid, allowing the company the means for "excelling at the basics and building for the future".

Q. How does the Company's grid modernization strategy compare to industry-accepted best practices in grid modernization?

A. The Company has identified the DOE's "Next Generation Distribution System Platform" (DSPx) as a tool that can provide a consistent understanding of the interrelationships of key functions and technology investments to support grid modernization goals. It is also deploying some of the "core components" of the DSPx, and correctly states that"[w]hen foundational components are integrated and work together as a platform, it allows additional applications to be built, providing even greater potential benefits, with both the foundational components and applications working together interdependently."[11]

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[11] Direct Testimony of Richard T. Blumenstock on behalf of Consumers Energy Company, February 2020, Case No. U-20697, page 38, line 23.

However, in order to align with industry best practices, this strategy should incorporate policy and customer priorities, such as those identified through stakeholder workshops and summarized in Staff's Electric Distribution Planning Stakeholder Process report[12], in order to set the pace and scope of grid modernization investments. This investment strategy should extend to the selection of pilot programs and demonstration projects, invite stakeholder input on the priorities selected, and have a process to measure outcomes and performance over time in order to allow for course correction as necessary.

Q. What is your overall reaction to the Company's grid modernization strategy?

The primary capabilities that Consumers has chosen are sound, but the Company can do more to expand the selection of portfolio of viable investments and strategies to include more DER solutions. For instance as part of an its Integrated Grid Planning process, Hawaiian Electric Company submits a five-year plan with discrete investments, programs, and pricing proposals to the commission for its review.[13] The solutions evaluated as part of this plan include: 1) utility developed resources 2) utility procured resources (grid scale and aggregated / DERs) 3) DER and DR programs and 4) tariffs.

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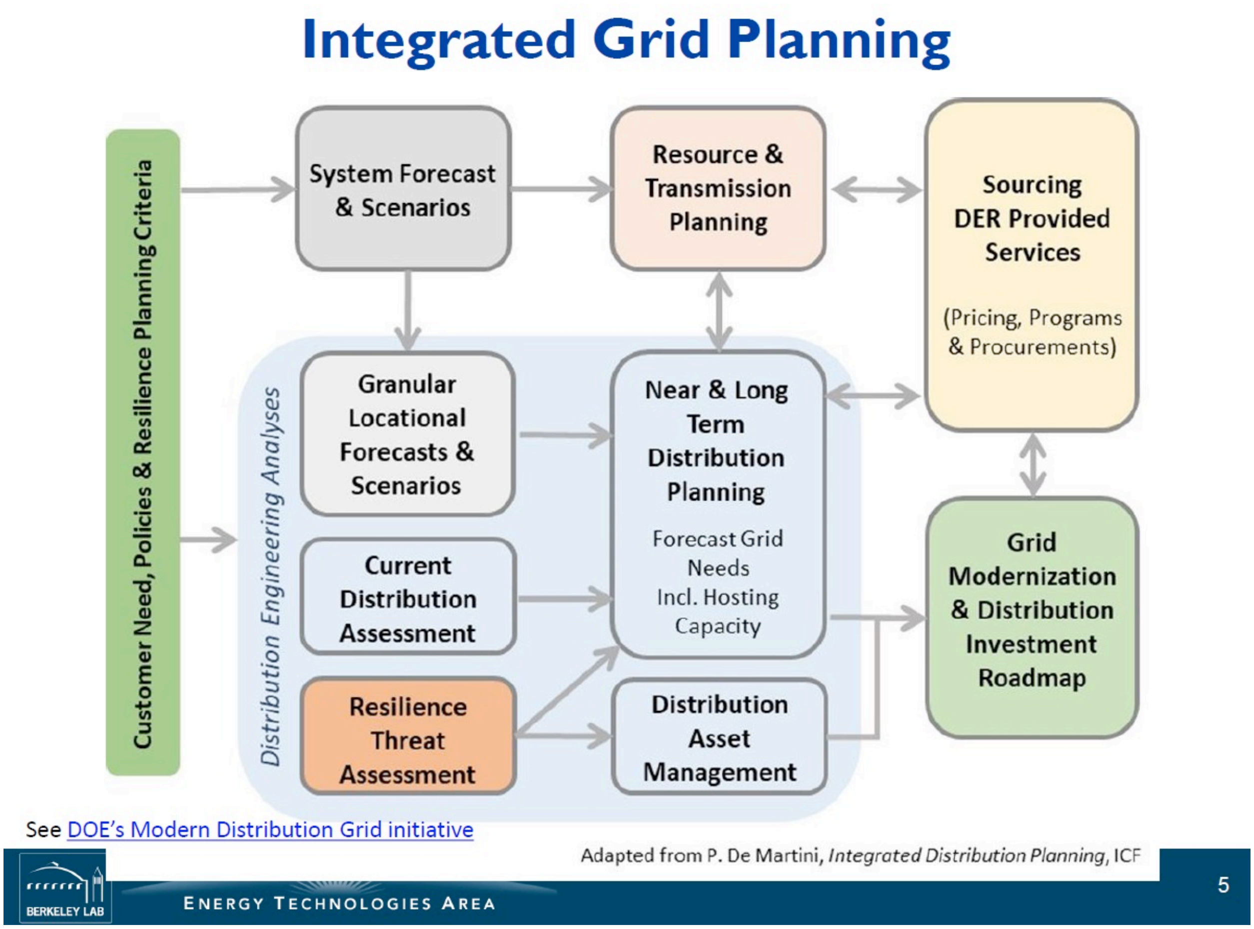
[12] MI Power Grid – Electric Distribution Planning Stakeholder Process; MPSC Staff Report; April 1, 2020 https://www.michigan.gov/documents/mpsc_old/Distribution_Planning_Report_Final_685525_7.pdf

[13] https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A18G12B05711C00464

The following is a figure that reflects an Integrated Grid Planning process, including the sourcing of diverse solutions:

Figure 1. Elements of Integrated Grid Planning. Data Source: L. Schwartz; Lawrence Berkeley National Laboratory (LBNL); Adapted from P. De Martini, Integrated Distribution Planning, ICF[14].



[14] Distribution Planning Regulatory Practices in Other States; Lisa Schwartz; Berkeley Lab; Presentation to the Oregon Public Utility Commission; May 21, 2020 https://www.oregon.gov/puc/utilities/Documents/DSP-Schwartz-Presentation.pdf

Q. Does the Company consider distributed energy resources in its grid modernization strategy?

A. Yes. One of the three primary "advanced grid capabilities" that the Company is focused on building over the next five years is increasing coordination and management of an increasing penetration of DER on the electric distribution system. In the near-term, the Company specifically plans to deploy Company-owned battery energy storage systems across a few locations on its distribution system, including at the residential level.

The Company also highlights its investment in an Advanced Distribution Management System (ADMS) and Distributed Energy Resource Management System (DERMS), in order to support the deployment of small-scale DER technologies.

Q. What is your overall reaction to the Company's treatment of DER as a part of its overall grid modernization strategy?

A. The Company's Grid Modernization Strategy could benefit from a more long-range view than what it presents in this case. This could take the form of a stand-alone long-range grid modernization plan that is aligned with the distribution planning process, or as an expanded component of the EDIIP.

The Grid Modernization Strategy could look beyond investments to help monitor and manage DERs, and consider the capabilities needed to source DERs to provide grid services and meet the objective of MI Power Grid to "maximize the benefits of the transition to clean, distributed energy resources for Michigan residents and businesses"[15]. Currently, the Company has indicated through discovery that it does not "study or calculate the impacts of distributed generation on the distribution system after

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[15] MI Power Grid – Electric Distribution Planning Stakeholder Process; MPSC Staff Report; April 1, 2020 https://www.michigan.gov/documents/mpsc_old/Distribution_Planning_Report_Final_685525_7.pdf

interconnection projects are complete"[16]. It also "has not studied DER penetration values at the substation or circuit level", which is a starting point for understanding DER impacts and begin to forecast DERs across these assets.

In addition, the Company has indicated it has "yet to find any compelling research" supporting the claim "that DG customers benefit the grid"[17].

Q. How do you react to this assertion?

A. To the extent that the Company is suggesting that distributed generation does not benefit the grid, I strongly disagree. Distributed generation and other DER can benefit the grid in several ways (which I discuss further in Section V of my testimony). The Company's assertion to me indicates that its grid modernization strategy does not optimally account for or leverage distributed generation or other DER.

Q. What do you recommend to the Commission regarding the Company's grid modernization strategy?

A. Again, I recommend that the Commission direct the Company to investigate IDP—including its several components which I have described in my testimony—through the long-term stakeholder-informed distribution planning process being carried out in Docket No. U-20147. As I have explained, IDP directly and deliberately accounts for distributed generation and other DER as potentially valuable grid resources. By implementing IDP, I believe the Company will be better positioned to develop a robust grid modernization strategy.

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[16] Company response to ELPC-CE-896

[17] Direct Testimony of Hubert W. Miller III on behalf of Consumers Energy Company, February 2020, Case No. U-20697, page 24, line 23.

V. VALUE OF DISTRIBUTED GENERATION

Q. How does the Company currently compensate distributed generation on its system?

A. The Company compensates distributed generation using the Net Energy Metering (NEM) program. My understanding is that the program credits customers for net excess generated power put back on the grid at their full retail rate (which includes production, transmission, and delivery charges for most customers).

Q. What method for compensating distributed generation does the Company's propose in this case?

A. The Company proposes the "Inflow/Outflow" method. Under this method, distributed generation customers are billed their normal rates for all power taken from the grid (Inflow), and provided a production credit for all excess generated power put back on the grid (Outflow). The Company proposes that the production credit would include its embedded production rates (power supply less transmission), and that the production credit would be applied as an offset to only the production section of customers' monthly energy bills (as opposed to the NEM program, which applies a credit to the customer's full monthly bill, minus any fixed charges).

Q. What is the Company's justification for crediting DG customers using its embedded production rates?

A. My understanding is that the Company's proposed method is based on their interpretation of Section 177(4) of Public Act 342 of 2016. However the Company also explains that it does not propose to include transmission in the outflow credit because it believes that would compensate the customer "for a service they are not providing." I understand this to mean that the Company believes that distributed generation does not benefit the grid.

Q. Can distributed generation benefit the grid?

Yes. Distributed generation can benefit the grid through various value streams associated with these technologies, including:

- reduction in peak demand – which can result in the deferral of planned capital investments in the long run and lower energy costs in the short term,
- reduction in energy losses – which reduce the energy that needs to be generated to offset these losses, and
- diversification of the energy supply mix – which can increase "energy surety"[18] or uninterrupted service by reducing vulnerabilities associated with the loss of fuels, in addition to enhancing resiliency
- voltage regulation – which involves maintaining reliable and constant voltage within a transmission or distribution line to ensure electrical equipment is not damaged
- contingency response– which involves maintaining frequency in response to an unexpected failure or outage of a system component (e.g., generator, transmission line).
- regulating reserves– which involves maintaining frequency during normal (non-event) conditions. [19]

Q. Are there other ways in which distributed generation can benefit the grid?

[18] https://www.nrel.gov/docs/fy13osti/57744.pdf
[19] Cook, Jeffrey J., Kristen Ardani, Eric O'Shaughnessy, Brittany Smith, and Robert Margolis. 2018. Expanding PV Value: Lessons Learned from Utility-led Distributed Energy Resource Aggregation in the United States. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71984. https://www.nrel.gov/docs/fy19osti/71984.pdf.

A. Emerging efforts have attempted to pursue more active approaches to leveraging DERs in a way that expands its benefits to include ancillary services. For instance, a recent study[20] by the National Renewable Energy Laboratory (NREL) found that "Distributed PV and other emerging distributed energy resources (DERs) like battery storage and electric vehicles (EVs) may provide demand response, voltage regulation, and other grid services".

In assessing the performance of DER aggregation efforts across the country, NREL arrived at a series of recommendation and lessons learned on proactive approaches for leveraging DERs in system planning.

One case study grouped diverse technologies across various homes, including:

- 10 Rooftop PVs with Smart Inverters
- 80 Bidirectional EV Chargers with batteries and Rooftop PVs
- 2 Large Battery Storage systems

These DER were managed to provide various grid services, resulting in the following observations:

- "The batteries demonstrated frequency response."
- "The EVs with bidirectional chargers consumed excess electricity, including during times of higher grid-connected wind generation from 10 PM – 4 AM and PV generation from 12 – 4 PM. The EVs then discharged electricity to the grid

[20] Cook, Jeffrey J., Kristen Ardani, Eric O'Shaughnessy, Brittany Smith, and Robert Margolis. 2018. Expanding PV Value: Lessons Learned from Utility-led Distributed Energy Resource Aggregation in the United States. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71984. https://www.nrel.gov/docs/fy19osti/71984.pdf.

during the peak demand period (6 – 9 PM), when renewable generation was lower."

- "Finally, the 10 PV arrays with smart inverters provided voltage support in response to voltage signals from a local transformer."[21]

When various DER technologies are aggregated to work in concert, they can potentially come together as a "virtual power plant" (VPP) to provide a number of energy and ancillary services. These aggregated resources can potentially work alongside the Company's Grid Modernization strategy and Energy Waste Reduction programs to continue to deliver on the Company's "clean and lean" approach of keeping bills affordable and limiting customer risk. A prime example of this concept at work is underway in Hawaii Electric Company (HECO) territory, where the utility is collaborating with Sunrun to deploy 1,000 distributed, residential solar-plus-storage systems in Oahu to offer 4.3 MWs of capacity and into the HECO grid[22]. The technology was stated to also have autonomous capabilities. This VPP will begin providing service this year in response to peak demand requirements over the next four years and will contribute to advancing the island's renewable energy goals.

I would note that through discovery, the Company indicated it was in the early stages of deploying battery systems in a circuit across 50 residential customers in collaboration with Sunverge Energy to explore "different values that batteries could provide to the overall grid, such as potential investment deferral, resiliency and reliability, while also

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[21] Cook, Jeffrey J., Kristen Ardani, Eric O'Shaughnessy, Brittany Smith, and Robert Margolis. 2018. Expanding PV Value: Lessons Learned from Utility-led Distributed Energy Resource Aggregation in the United States. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71984. https://www.nrel.gov/docs/fy19osti/71984.pdf.

[22] https://www.utilitydive.com/news/sunrun-partnership-enhances-hecos-ability-to-tap-into-der-systems-when-pow/562733/

providing backup of critical loads for pilot participants."[23] This suggests that the Company appears to recognize that DERs can in concept provide meaningful benefits to both customers and the grid, even if it has not yet systematically incorporated that approach into its distribution planning and grid modernization strategies.

Q. Has the Company evaluated the grid benefits of distributed generation?

A. It does not appear that the Company has evaluated the grid benefits of distributed generation in any thorough or systematic manner. Though the Company acknowledged in a discovery response[24] the "reduced loading on equipment, reduced electrical losses, and voltage support" benefits that distributed generation can provide, it noted that these benefits may be realized "if and to the extent that interconnecting distributed generation systems provide such benefits and those benefits can be directly and appropriately quantified". JCEO Witnesses Rabago[25] and Chan[26] have provided extensive references on research that identify these grid benefits.

Though the Company is pursuing pilots that may provide some insight on how technologies like battery storage could work in concert with solar generation, it should take a more holistic appraoch to assessing what these benefits can mean for the system at broader scales. The EDIIP may provide an ideal forum for identifying how distributed generation can more effectively meet grid needs currently addressed through more costly options. This identification of benefits may also inform the comprehensive VOS analysis

[23] Company response to ELPC-CE-130.
[24] Company response to ELPC-CE-1288.
[25] Rabago at 46.
[26] Chan at 18.

recommended by JCEO witness Chan[27] that can compensate customers for the value distributed generation can provide the utility, other customers, and society in general.

Q. How can IDP help inform an evaluation of the value of distributed generation to the grid?

The magnitude and the nature of the value associated with distributed generation depends in part on the location of the resource, its technological attributes, and how it is deployed and dispatched. Company witness Blumenstock appears to acknowledge this in a discovery response[28] , where he states that “interconnecting distributed generation systems” can result in result in reduced loading on equipment, reduced electrical losses, and voltage support “if and to the extent that interconnecting distributed generation systems provide such benefits and those benefits can be directly and appropriately quantified”. This highlights the importance of an IDP process, because such a process involves an examination of grid needs over the short- and long-term, and an evaluation of the value that distributed generation and other DER can provide in addressing those needs. Distribution system planning often involves a “Grid Needs Assessment” that identifies potential shortfalls in the planning horizon across required grid services. As these grid needs become more transparent through IDP, the Company should consider portfolios of distributed generation and other DER as viable solutions to fill these requirements, and value those solutions based on their ability to meet the short- and long-term needs of the grid.

Q. What do you recommend to the Commission with respect to the value of distributed generation to the grid?

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[27] Chan at 5.
[28] Company response to ELPC-CE-1288.

A. First, I recommend that the Commission direct the Company to include, as a part of its compensation to DG customers, compensation for the value of distributed generation to the grid. Second, I recommend that the Commission further investigate the value of distributed generation to the grid as a part of the Value of Solar study that JCEO witnesses Rabago and Chan describe in more detail. Third, I reiterate my recommendation that the Commission direct the Company to investigate IDP, because over the long term, that process can help inform and improve the Company's assessment of the value of distributed generation and other DER to the grid.

VI. GRID STORAGE PILOTS

Q. Please summarize your understanding of the Company's planned battery energy storage system pilots.

A. The Company is proposing a new "Grid Storage" sub-program which includes plans for three battery projects. The first is a battery at a solar farm and aims to engage in smoothing out the generation profile of the solar facility. The second is a portable battery the Company is deploying in hopes of deferring a projected substation capacity upgrade. The third project is a battery designed to allow islanding and ensure continuity of electric service through a circuit outage. The Company is projecting "Grid Storage" capital expenditures of $10 million in the 2021 Test Year across the three projects.

Q. How do the Company's planned battery storage pilots relate to its broader grid modernization strategy?

A. The objectives of the three pilot projects align well with the three primary advanced grid capabilities of the Company's Grid Modernization Strategy - reliability and resilience, system efficiency and optimization, and DER integration. In addition to the large scale battery projects previously listed, the Company indicated it has also been conducting a pilot to test the installation of "Company-owned residential behind-the-meter batteries on a circuit"[29].

Q. Do you have recommendations for the Company's proposed implementation of battery storage pilots?

My recommendations echo those expressed by Michigan distribution planning stakeholders[30] on pilot programs in general and summarized in the Electric Distribution Planning Stakeholder Process MPSC Staff Report. One recommendation called for providing guidance on pilot design issues including on: "where pilots are necessary and what problems need to be resolved", timeframes for "when distribution planning matters to appropriately align with state policy objectives", and potential rate designs that could "better align end user pricing with generation, transmission, and distribution variable costs from a time and location aspect".

The Company's pilot programs appear to be spread across proceedings, press releases, and other company documents. Without a more formalized structure accompanied by periodic reporting, and that includes design elements like what is in scope, what isn't being addressed, and timing to inform a specified process, it is difficult to gauge how meaningful these pilot efforts will turn out to be.

For instance, the Company stated that in 2017 it initiated a pilot program to "explore whether or not an anticipated capacity upgrade….could be deferred through the use of

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[29] Direct Testimony of Richard T. Blumenstock on behalf of Consumers Energy Company, February 2020, Case No. U-20697, page 40, line 10.

[30] MI Power Grid – Electric Distribution Planning Stakeholder Process; MPSC Staff Report; April 1, 2020 p.14 https://www.michigan.gov/documents/mpsc_old/Distribution_Planning_Report_Final_685525_7.pdf

targeted energy efficiency and demand response”[31]. It added that as it “continued to develop lessons learned from these pilots, the Company may become better able to consider non-wires alternatives as solutions more widely”.

Though progress may have been made, this dynamic highlights another recommendation expressed in Staff’s report of encouraging design elements on pilot programs to be developed upfront, in order to avoid the appearance of a cycle where ideas continue to be tested without a clear path to resulting in larger deployments.

Overall, I recommend that in order to strengthen the Company’s storage and other pilots, the Commission direct the Company, in future applications in which the Company proposes pilots, to:

- Clearly articulate intended outcomes from those pilot proposals, and;
- Clearly articulate a path for the pilot to lead to large-scale deployment.

VII. DISTRIBUTED ENERGY RESOURCE MANAGEMENT SYSTEMS

Q. What are Distributed Energy Resource Management Systems (“DERMS”)?

Though Distributed Energy Resource Management System (“DERMS”) capabilities are still evolving, a recent report[32] described the technology as one allows for the management of a “variety of both aggregated and individual DERs to support various objective functions related to grid support, customer value, or market participation. This may be accomplished through software only, or a combination of software and hardware.”

[31] Direct Testimony of Richard T. Blumenstock on behalf of Consumers Energy Company, February 2020, Case No. U-20697, page 212, line 18.

[32] Pacific Gas & Electric. Electric Program Investment Charge (EPIC) 2.02 – Distributed Energy Resource Management System. January 2019. https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-2.02.pdf

Q. Please summarize your understanding of the Company's planned investment in Distributed Energy Resource Management Systems ("DERMS").

A. The Company is proposing to deploy the first phase of a "small-scale" DERMS deployment over a period of 24 to 36 months, at an estimated cost of $3,000,000[33]. Its stated objective for this investment is to "optimize and control a limited number of DERs and address potential local operational challenges associated with DER penetration at the circuit and/or substation level".

Through discovery, the Company added it wouldn't just focus on the challenges associated with DERs, but would also focus on understanding the "opportunities and benefits associated with DERs using DERMS"[34]. These opportunities could include using DERMS to "help support solar smoothing" by managing solar generation and battery storage, as well as help "support volt-var management" of DERs by providing or absorbing "real and reactive power as required".

The Company stated that it would use DERMS in its first phase of deployment to control solar generation and battery storage systems[35], but does not plan to include any customer-sited DER systems in this phase[36]. The Company indicated, however, that it plans to evaluate installations that may include customer-sited, DER communications and control assets to respond to its request for services in its DERMS operation "and may present proposals to do so in future regulatory proceedings"[37].

[33] Direct Testimony of Richard T. Blumenstock on behalf of Consumers Energy Company, February 2020, Case No. U-20697, page 153, line 1.
[34] Company response to ELPC-CE-1284.
[35] Company response to ELPC-CE-1285.
[36] Company response to ELPC-CE-1287.
[37] Company response to ELPC-CE-1286.

Q. Do you have concerns associated with the Company's planned investment in Distributed Energy Resource Management Systems ("DERMS")?

Yes. I am concerned that the Company is planning to invest in DERMS at a stage of DER adoption that does not merit that investment. A recent report[38] from GridLab stated that DERMS technologies were "nascent" and found it hard to conclude at this time that these technologies could be supported even at high penetrations of DERs. Further, I am concerned the Company is planning to invest in DERMS without sufficiently considering (and therefore, potentially excluding) other potential methods of managing and coordinating DER technologies. By doing so, the Company may be failing to consider the potential negative impacts (ie curtailment) of DERMS on DERs.

Q. What experience have other utilities had with DERMS?

A. As I indicated earlier, DERMS is still an emerging and evolving area in the grid modernization space. Utilities across various regions[39] are still digesting the early lessons learned and challenges in coordinating and executing on the promise of DERMS investments. Managing a broad range of DER technologies, developing compensation mechanisms for providers of various grid services, and pursuing associated investments in cost effective manner has been very challenging in these early stages.

Q. How does Consumers intend to implement DERMS?

In discovery response 20697-ELPC-CE-126, the Company provided a description on how DERMS investments would operate by indicating it would "use DERMS to control the

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[38] Sara Baldwin, Ric O'Connell, Curt Volkmann. A Playbook for Modernizing the Distribution Grid; Volume I: Grid Modernization Goals, Principles and Plan Evaluation Checklist. P.14 IREC and GridLab. May 2020. https://irecusa. org/publications/ and https://gridlab.org/publications/.

[39] Pacific Gas & Electric. Electric Program Investment Charge (EPIC) 2.02 – Distributed Energy Resource Management System. January 2019. https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-2.02.pdf

voltage, power factor, real power, and reactive power settings of DERs." However, the Company did not provide specifics at this time on how it would compensate DER sites for these additional services to the grid they would provide.

In the subsequent discovery response 20697-ELPC-CE-866, the Company indicated it "may consider compensating a DER when the DER is able to provide an additional service and the Company had a need for such services, however the method by which a DER would be compensated is dependent on how the program is established and administered". This response concerns me.

Q. Why does this concern you?

A. The Company should develop a proposal that details how DERs would participate (voluntary, mandatory etc.), the eligible technologies that would be managed, how these resources would compensated if the Company reduces its power output, alonside other considerations. Ideally, the Company should define this proposal before it invests in DERMS, especially since the effectiveness of these investments rely on DER participation levels and the ability to manage the settings of DERs as previously described.

Q. Are there any other reasons why the Company's proposed investment in DERMS concerns you?

A. Yes. I believe that current installed capacity levels of distributed generation systems is still too low[40], in my view, to merit investment in DERMS. The Company has stated it was "not currently experiencing any local operational challenges associated with DER penetration"[41] and that "experience and research shows that operational challenges begin

[40] Company response to ELPC-CE-878
[41] Company response to ELPC-CE-126.

when DER penetration reaches between 20% and 30% at the substation and circuit level". The Company's proposal for DERMS references "potential" local operational challenges as a justification for the investments identified. An alternate approach could involve the Company collecting data on the nature of these "operational challenges" and identify potential strategies, such as demand flexibility and reactive power management as described in the Grid Modernization strategy.

Q. Please elaborate on the approaches to DER management and control, beyond DERMS, that the Company should pursue.

In its November 21, 2018 Order in Case No. U-20147, the Commission expressed that with the "increased use of DERs and upgrades to hardware and software systems to support distribution operations and customer engagement, the sequencing and integration of controls, sensors, communications, and data management systems will be important for safety, reliability, and cost." It further added that "[u]nderstanding the expected costs, timeframes, functions, and integration risk issues on the front end will assist with the Commission's prudency reviews in rate cases and ongoing monitoring as technology projects are implemented".

The Company indicated it has "engaged initial whitepaper research and literature reviews regarding the impacts and methods of coordinating DERs with volt-var optimization", but "has not conducted any internal testing or field studies specific to its own system"[42] As I discuss later, voltage optimization can be used to "lower the cost and increase the speed at which rooftop solar can be added to the grid"[43]. In addition, concepts such as

[42] Company response to ELPC-CE-1282.
[43] Hawaiian Electric Company, Inc.; Varentec Grid Optimization Project. https://www.hawaiianelectric.com/about-us/our-vision-and-commitment/investing-in-the-future/varentec-grid-optimization-project

Autonomous Energy Grids[44] may allow assets connected to the grid to "self-optimize" and maintain reliable operation, without the needs for a large number of controls across these assets that would create an increasing level of complexity.

I believe a more thorough proposal for a DERMS deployment that illuminates the progression of the deployment and anticipated end-state, takes into account its comparative advantages and disadvantages with other technologies and approaches, and demonstrates consideration for customer participation elements such as compensation and the mandatory or voluntary nature of associated programs, is warranted before investments in the technology move forward.

Q. What do you recommend to the Commission with respect to the Company's proposed investment in DERMS?

A. I recommend that the Commission disallow the Company's proposed expenditures related to DERMS at this time, because the Company has not provided sufficient evidentiary support demonstrating that its proposed investment in DERMS is necessary or reasonable.

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[44] Kroposki, et al; National Renewable Energy Laboratory; 2018; https://scholarspace.manoa.hawaii.edu/bitstream/10125/50229/1/paper0342.pdf

VIII. CONSERVATION VOLTAGE REDUCTION

Q. What is conservation voltage reduction (CVR)?

A. GridLab and Interstate Renewable Energy Council define[45] Integrated Volt / VAR Control (IVVC) as "a process of controlling voltage and reactive power flow on the distribution system to improve overall system performance, allowing a utility to reduce electrical losses, eliminate voltage profile problems and reduce electrical demand." Conservation Voltage Reduction (CVR) is a specialized application of IVVC, and can reduce overall voltage levels, while ensuring these voltages remain within acceptable standards for electric distribution. As the Company explains, CVR has "the capability to optimize service-point, or customer meter, voltages to reduce energy demand without requiring active participation or behind-the-meter investment by customers". Reductions in distribution system voltage have been demonstrated to result in reductions in energy consumption across the electric circuits on which this practice is applied.

Q. Please summarize your understanding of the Company's planned investment in conservation voltage reduction (CVR).

A. The Company's plan for implementing CVR involves several separate capital projects (totaling $2,851,000 in the 2021 Projected Test Year), including installing Distribution SCADA, regulator controllers and capacitor controllers on targeted circuits to ensure those circuits can enable CVR. The Commission approved CVR-related capital expenditures in a previous Order in Case No. U-20165.

Q. Has the Company articulated a plan to measure the performance of its CVR plan?

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[45] Sara Baldwin, Ric O'Connell, Curt Volkmann. A Playbook for Modernizing the Distribution Grid; Volume I: Grid Modernization Goals, Principles and Plan Evaluation Checklist. IREC and GridLab. May 2020. https://irecusa.org/publications/ and https://gridlab.org/publications/.

A. Yes. The Company states that its initial testing of CVR (in 2019) creates a baseline, and that once CVR is fully enabled and operational on a circuit, its meter data would provide "sufficient telemetry to ensure continuous measurement and verification of CVR performance."

Q. Do you have any concerns with the Company's proposed plan to measure and verify the performance of its CVR investments?

The Company's proposed approach to the measurement and verification of CVR performance appears sound. However, the Company should also file periodic reports with metrics detailing the level of voltage reductions, loss reductions, service quality issues encountered, energy savings, demand reductions, and greenhouse gas emission reductions that can be attributed to the performance of its CVR deployments. The Company has already provided forecasts of some of these potential metrics in its CVR deployment plan and recognized that as it "continues its initial testing", its forecasts "may be refined". Reporting on these performance metrics over time could inform future decisions on what modernization investments should continue to be pursued and expanded on, or where course correction may be needed.

Q. How does the Company's CVR plan relate to its broader grid modernization strategy?

A. Investments in IVVC technology and grid modernization can result not only in energy reductions, but also may provide additional visibility and operational flexibility in responding to a variety of dynamic system conditions. This plan aligns well with the Company's focus on advancing "system efficiency and optimization" capabilities.

Q. Do you have any concerns with the Company's proposed implementation of its CVR plan?

A. Though the Company's commitment to waste reduction through CVR is notable, the Company should explore the capabilities of the broader IVVC offerings to actively manage dynamic system conditions. Regions with significant levels of DERs, such as Hawaii, have begun to explore[46] how the broad suite of IVVC offerings in voltage and reactive power management may be used to safely "add more rooftop solar systems to the grid" and "lower the cost and increase the speed at which rooftop solar can be added to the grid"[47]. These options may be a more preferable means of managing dynamic conditions on the grid, if CVR is already being pursued, than separate and potentially more costly investments, such as DERMS.

Q. What do you recommend to the Commission with respect to the Company's proposed investments in CVR?

A. I recommend that the Commission direct the Company to file periodic reports with metrics detailing the level of voltage reductions, loss reductions, service quality issues encountered, energy savings, demand reductions, and greenhouse gas emission reductions that can be attributed to the performance of its CVR deployment.

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[46] Asano, Marc & Wong, Frankie & Ueda, Reid & Moghe, Rohit & Rahimi, Kaveh & Chun, Hong & Tholomier, Damien. (2019). On the Interplay between SVCs and Smart Inverters for Managing Voltage on Distribution Networks. 1-5. 10.1109/PESGM40551.2019.8973743.

[47] Hawaiian Electric Company, Inc.; Varentec Grid Optimization Project. https://www.hawaiianelectric.com/about-us/our-vision-and-commitment/investing-in-the-future/varentec-grid-optimization-project

IX. CONCLUSION

Q. Please summarize your recommendations.

A. Broadly, my testimony in this proceeding recommends that the Company better leverage distributed generation and other DER as a key tool in its distribution planning and grid modernization strategy going forward, because distributed generation and other DER can provide value to the grid. Specifically, I recommend that the Commission:

- Direct the Company to include, as a part of its compensation to DG customers, compensation for the value of distributed generation to the grid;
- Further investigate the value of distributed generation to the grid as a part of the Value of Solar study that JCEO witnesses Rabago and Chan describe in more detail;
- Direct the Company to investigate IDP—including its several components which I have described in my testimony—through the long-term stakeholder-informed distribution planning process being carried out in Docket No. U-20147;
- Direct the Company, in future applications in which the Company proposes pilots, to clearly articulate intended outcomes from those pilot proposals, and clearly articulate a path for the pilot to lead to large-scale deployment;
- Disallow the Company's proposed expenditures related to DERMS, and;
- Direct the Company to file periodic reports with the Commission including metrics detailing the level of voltage reductions, loss reductions, service quality issues encountered, energy savings, demand reductions, and greenhouse gas

emission reductions that can be attributed to the performance of its CVR deployment.

Q. Does this conclude your testimony?

A. Yes.

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	)))))	Case No. U-20697

EXHIBITS OF

WILLIAM D. KENWORTHY

ON BEHALF OF

THE ECOLOGY CENTER
THE ENVIRONMENTAL LAW & POLICY CENTER
THE GREAT LAKES RENEWABLE ENERGY ASSOCIATION
THE SOLAR ENERGY INDUSTRIES ASSOCIATION
AND VOTE SOLAR

June 24, 2020

Testimony and Comments of William D. Kenworthy

Regulatory Director, Midwest
Vote Solar
June 1, 2020

Testimony

Direct Testimony of William D. Kenworthy on behalf of the Environmental Law and Policy Center, the Ecology Center, the Solar Energy Industries Association, and Vote Solar, *In the matter of the application of CONSUMERS ENERGY COMPANY for approval of Voluntary Green Pricing programs pursuant to Section 61 of 2016 PA 342*, Michigan Public Service Commission, Case No. U-20649, May 28, 2020.

Rebuttal Testimony of William D. Kenworthy on behalf of the Environmental Law & Policy Center and Vote Solar, *In the matter of Proposed Revisions to Rider Parallel Operation of Retail Customer Generating Facilities Community Supply*, Illinois Commerce Commission, Docket No. 19-1121, April 23, 2020.

Direct Testimony of William D. Kenworthy on behalf of the Environmental Law & Policy Center and Vote Solar, *In the matter of Proposed Revisions to Rider Parallel Operation of Retail Customer Generating Facilities Community Supply*, Illinois Commerce Commission, Docket No. 19-1121, February 21, 2020.

Direct Testimony of William D. Kenworthy on behalf of the Environmental Law and Policy Center, the Ecology Center, the Solar Energy Industries Association, and Vote Solar, *In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.* Michigan Public Service Commission, Case No. U-20561, November 6, 2019.

Direct Testimony of William D. Kenworthy on behalf of the Environmental Law and Policy Center, the Ecology Center, the Solar Energy Industries Association, and Vote Solar, *In the matter of the Application of Indiana Michigan Power Company for authority to increase its rates for the sale of electric energy and for approval of depreciation rates and other related matters,* Michigan Public Service Commission, Case No. U-20359, October 17, 2019.

Rebuttal Testimony of William D. Kenworthy on Behalf of the Environmental Law and Policy Center and Vote Solar*, In the Matter of the Joint Application of Wisconsin Power Company, Wisconsin Gas LLC, and Wisconsin Public Service Corporation to Adjust Electric, Natural Gas and Steam Rates,* Wisconsin Public Service Commission, Docket No. 5-UR-109, October 4, 2019.

Rebuttal Testimony of William D. Kenworthy on behalf of the Environmental Law and Policy Center and the Iowa Environmental Council*, In re: Interstate Power & Light Compan*y, Iowa Utilities Board, Docket No. RPU-2019-001, September 10, 2019.

Direct Testimony of William D. Kenworthy on Behalf of the Environmental Law and Policy Center and Vote Solar*, In the Matter of the Joint Application of Wisconsin Power Company, Wisconsin Gas LLC, and Wisconsin Public Service Corporation to Adjust Electric, Natural Gas* *and Steam Rates,* Wisconsin Public Service Commission, Docket No. 5-UR-109, August 23, 2019.

Rebuttal Testimony of Will Kenworthy on behalf of the Environmental Law and Policy Center, the Ecology Center, the Solar Energy Industries Association, and Vote Solar, *In the matter of Application of DTE ELECTRIC COMPANY for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief*, Michigan Public Service Commission, Case No. U-20471, August 21, 2019.

Direct Testimony of William D. Kenworthy on behalf of the Environmental Law and Policy Center and the Iowa Environmental Council, *In re: Interstate Power & Light Company*, Iowa Utilities Board, Docket No. RPU-2019-001, August 1, 2019.

Rebuttal Testimony of Will Kenworthy on behalf of the Environmental Law and Policy Center, the Ecology Center, the Solar Energy Industries Association, and Vote Solar, *In the matter of the Application of DTE Electric Company for authority to increase its rate schedules and rules governing the distribution and supply of electric energy, and for other relief,* Michigan Public Service Commission, Case No. U-20162, November 28, 2018.

Direct Testimony of Will Kenworthy on behalf of the Environmental Law and Policy Center, the Ecology Center, the Solar Energy Industries Association, and Vote Solar, *In the matter of the Application of DTE Electric Company for authority to increase its rate schedules and rules governing the distribution and supply of electric energy, and for other relief,* Michigan Public Service Commission, Case No. U-20162, November 7, 2018.

Comments

Comments of Vote Solar in the Matter of Updating Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities Established Under Minn. Stat. § 216B.1611, Minnesota Public Service Commission Docket No: E-999/CI-16-521, September 19, 2018.

Comments of Vote Solar, the Environmental Law and Policy Center, Natural Resources Defense Council, and Plugged In Strategies on the Michigan Distributed Planning Framework: MPSC Report. *In the matter, on the Commission's own motion, to open a docket for certain regulated electric utilities to file their five-year distribution investment and maintenance plans and for other related, uncontested matters.* Case No. U-20147, October 5, 2018.

Comments of Vote Solar, the Environmental Law and Policy Center, Natural Resources Defense Council, and Plugged In Strategies on the Indiana Michigan Power Company's draft *Michigan Five Year Distribution Plan for 2019-2023* per the Commission's November 21, 2018 Order in Case No. U-20147, December 21, 2018.

Comments of Vote Solar in the Matter of the Commission's Inquiry into Standby Service Tariffs, Minnesota Public Service Commission Docket No: E999/CI-15-115, February 19, 2019.

Comments of Vote Solar in the Matter of a Commission Investigation to Identify and Develop Performance Metrics, and Potentially, Incentives for Xcel Energy's Electric Utility Operations, , Minnesota Public Service Commission Docket No: E002/CI-17-401, May 6, 2019.

Reply Comments of Vote Solar in the Matter of a Commission Investigation to Identify and Develop Performance Metrics, and Potentially, Incentives for Xcel Energy's Electric Utility Operations, , Minnesota Public Service Commission Docket No: E002/CI-17-401, June 6, 2019.

Supplemental Comments of Vote Solar in the Matter of the Commission's Inquiry into Standby Service Tariffs, Minnesota Public Service Commission Docket No: E999/CI-15-115, September 23, 2019.

Question:

1. For Category 1 (residential distributed generation systems < 20kW) of the current distributed generation program, please determine the following values. Please include all calculations to determine these values.

   a. Total kW available for Category 1 under the program (given soft cap of 0.5% of average in-state peak load).
   b. Current amount of installed/operational kW in Category 1.
   c. Remaining amount of kW available for installation under Category 1 program based on total installed/operational kW (given total kW available as determined in a. and current amount of kW installed/operational in b.).
   d. Remaining percentage available in the Category 1 program currently based on installed/operational distributed generation systems.
   e. Current amount of kW of pending applications for Category 1.
   f. Total current amount of installed/operational kW in Category 1 plus current amount of kW of pending applications for Category 1.
   g. Remaining amount of kW that would be available for installation under Category 1 program given all installed/operational systems and assuming all pending applications were completed and operational.
   h. Remaining percentage available in the Category 1 program given all installed/operational systems and assuming all pending applications were completed and operational.
   i. For each of the months April 2019 through March 2020, the number of applications under Category 1 program and the number of kW requested in such applications.

Response:

a. The applicable Category 1 cap of the program can be calculated as 0.5% of the Consumers Energy average peak load for the preceding 5-year period. This calculation results in a current program cap of 36,405 kW.
b. The total installed capacity of active Category 1 program participants is 25,433 kW.
c. The remaining program capacity available for Category 1 systems can be calculated as the difference between the cap in part a. to this response (36,405 kW) and the amount of Category 1 installed capacity active in the program (25,433 kW). This calculation results in remaining Category 1 program capacity of 10,972 kW.
d. The remaining Category 1 program capacity can be calculated as the Category 1 program capacity available (10,972 kW) divided by the total Category 1 program cap (36,405 kW). This calculation results in remaining Category 1 program capacity of approximately 30.14%.
e. The Company has 2,510 kW of total capacity of pending or incomplete Category 1 applications for the Net Metering Program.

f. The total installed Category 1 program capacity (25,433 kW) plus the pending or incomplete Category 1 applications (2,510 kW) is 27,943 kW.
g. The total Category 1 program cap (36,405 kW) minus the sum of (i) the total installed Category 1 program capacity and (ii) the pending or incomplete Category 1 applications (27,943 kW) is 8,462 kW.
h. The remaining Category 1 program capacity calculated in part g. (8,462 kW) divided by the total Category 1 program cap (36,405 kW) is approximately 23.24%.
i. Please see the table below:

Month	Applications Reviewed	Total kW
2019-04	102	879
2019-05	156	1190
2019-06	168	1221
2019-07	138	1105
2019-08	154	1076
2019-09	145	1070
2019-10	170	1310
2019-11	121	969
2019-12	100	803
2020-01	134	1150
2020-02	108	729
2020-03	82	565
2020-04*	27	186

*Through April 14, 2020

KEITH G. TROYER
April 14, 2020

Question:

2. For Category 2 (distributed generation systems 20kW-150kW) of the current distributed generation program, please determine the following values. Please include all calculations to determine these values.
a. Total kW available for Category 2 under the program (given soft cap of 0.25% of average in-state peak load).
b. Current amount of installed/operational kW in Category 2.
c. Remaining amount of kW available for installation under Category 2 program based on total installed/operational kW (given total kW available as determined in a. and current amount of kW installed/operational in b.).
d. Remaining percentage available in the Category 2 program currently based on installed/operational distributed generation systems.
e. Current amount of kW of pending applications for Category 2.
f. Total current amount of installed/operational kW in Category 2 plus current amount of kW of pending applications for Category 2.
g. Remaining amount of kW that would be available for installation under Category 2 program given all installed/operational systems and assuming all pending applications were completed and operational.
h. Remaining percentage available in the Category 2 program given all installed/operational systems and assuming all pending applications were completed and operational.
i. For each of the months April 2019 through March 2020, the number of applications under Category 2 program and the number of kW requested in such applications.

Response:

a. The applicable Category 2 cap of the program can be calculated as 0.25% of the Consumers Energy average peak load for the preceding 5-year period. This calculation results in a current program cap of 18,203 kW.
b. The total installed capacity of active Category 2 program participants is 11,152 kW.
c. The remaining program capacity available for Category 2 systems can be calculated as the difference between the cap in part a. to this response (18,203 kW) and the amount of Category 2 installed capacity active in the program (11,152 kW). This calculation results in remaining Category 2 program capacity of 7,051 kW.
d. The remaining Category 2 program capacity can be calculated as the Category 2 program capacity available (7,051 kW) divided by the total Category 2 program cap (18,203 kW). This calculation results in remaining Category 1 program capacity of approximately 38.74%.

e. The Company has 2,746 kW of total capacity of pending or incomplete Category 2 applications for the Net Metering Program.
f. The total installed Category 2 program capacity (11,152 kW) plus the pending or incomplete Category 2 applications (2,746 kW) is 13,898 kW.
g. The total Category 2 program cap (18,203 kW) minus the sum of (i) the total installed Category 2 program capacity and (ii) the pending or incomplete Category 2 applications (13,898 kW) is 4,305 kW.
h. The remaining Category 2 program capacity calculated in part g. (4,305 kW) divided by the total Category 2 program cap (18,203 kW) is approximately 23.65%.
i. Please see the table below:

Month	Applications Reviewed	Total kW
2019-04	12	643
2019-05	9	975
2019-06	1	66
2019-07	2	178
2019-08	4	541
2019-09	5	437
2019-10	6	508
2019-11	4	614
2019-12	9	1280
2020-01	4	303
2020-02	2	377
2020-03	2	401
2020-04*	0	0

* Through April 14, 2020

KEITH G. TROYER
April 14, 2020

Question:

3. For Category 3 (methane digesters 150kW – 550kW) of the current distributed generation program, please determine the following values. Please include all calculations to determine these values.

   a. Total kW available for Category 3 under the program (given soft cap of 0.25% of average in-state peak load).
   b. Current amount of installed/operational kW in Category 3.
   c. Remaining amount of kW available for installation under Category 3 program based on total installed/operational kW (given total kW available as determined in a. and current amount of kW installed/operational in b.).
   d. Remaining percentage available in the Category 3 program currently based on installed/operational distributed generation systems.
   e. Current amount of kW of pending applications for Category 3.
   f. Total current amount of installed/operational kW in Category 3 plus current amount of kW of pending applications for Category 3.
   g. Remaining amount of kW that would be available for installation under Category 3 program given all installed/operational systems and assuming all pending applications were completed and operational.
   h. Remaining percentage available in the Category 3 program given all installed/operational systems and assuming all pending applications were completed and operational.
   i. For each of the months April 2019 through March 2020, the number of applications under Category 3 program and the number of kW requested in such applications.

Response:

a. The applicable Category 3 cap of the program can be calculated as 0.25% of the Consumers Energy average peak load for the preceding 5-year period. This calculation results in a current program cap of 18,203 kW.

b. The total installed capacity of active Category 3 program participants is 190 kW.

c. The remaining program capacity available for Category 3 systems can be calculated as the difference between the cap in part a. to this response (18,203 kW) and the amount of Category 3 installed capacity active in the program (190 kW). This calculation results in remaining Category 3 program capacity of 18,013 kW.

d. The remaining Category 3 program capacity can be calculated as the Category 3 program capacity available (18,013 kW) divided by the total Category 3 program cap (18,203 kW). This calculation results in remaining Category 3 program capacity of approximately 98.96%.

e. The Company has no pending applications for the Category 3 program.

f. The total installed Category 3 program capacity (190 kW) plus the pending or incomplete Category 3 applications (0 kW) is 190 kW.

g. The total Category 3 program cap (18,203 kW) minus the sum of (i) the total installed Category 3 program capacity and (ii) the pending or incomplete Category 3 applications (190 kW) is 18,013 kW.

h. The remaining Category 3 program capacity calculated in part g. (18,013 kW) divided by the total program cap (18,203 kW) is approximately 98.96%.

i. There were no additional Category 3 applications submitted to the Company during this time.

KEITH G. TROYER
April 14, 2020

EGI Contracts & Settlements

<u>Question:</u>

5. For each of Category 1, 2, and 3 distributed generation, when does Consumers Energy forecast that applications will reach the program cap?

<u>Response:</u>

Due to the uncertain impacts of the ongoing COVID-19 pandemic, it is not entirely clear when the program cap will be reached for Category 1, 2, and 3 distributed generation. Based solely on the historical participation rates in the Company's program, the program cap for Category 1 generation could be reached in October of 2020 and the program cap for Category 2 generation could be reached by the end of 2021. Historical participation levels may not be an accurate indication of future participation in the program due to the uncertainty caused by COVID-19. Since there has been a lack of anaerobic digestion interest in the program historically, there is no clear indication of when the program cap for Category 3 will be reached.

KEITH G. TROYER
April 14, 2020

EGI Contracts & Settlements

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	)))))	Case No. U-20697

EXHIBITS OF

KEVIN LUCAS

ON BEHALF OF

THE ECOLOGY CENTER
THE ENVIRONMENTAL LAW & POLICY CENTER
THE GREAT LAKES RENEWABLE ENERGY ASSOCIATION
THE SOLAR ENERGY INDUSTRIES ASSOCIATION
AND VOTE SOLAR

June 24, 2020

KEVIN M. LUCAS

SOLAR ENERGY INDUSTRIES ASSOCIATION

Mr. Lucas is Director of Rate Design for the Solar Energy Industries Association (SEIA). SEIA is the national trade association for the U.S. solar industry. SEIA is leading the transformation to a clean energy economy, creating the framework for solar to achieve 20% of U.S. electricity generation by 2030. SEIA works with its 1,000 member companies and other strategic partners to fight for policies that create jobs in every community and shape fair market rules that promote competition and the growth of reliable, low-cost solar power.

Since 2010, Mr. Lucas has worked in the energy and environment industry focusing on policies such as renewable energy, energy efficiency, and greenhouse gas reduction. In his role at SEIA, Mr. Lucas develops expert witness testimony for rate cases, integrated resource plans, and other regulatory proceedings. He is actively involved in the New York Reforming the Energy Vision docket, with a focus on distributed energy resource valuation and rate design. Prior to joining SEIA, Mr. Lucas worked for the Alliance to Save Energy, a Washington DC-based nonprofit focused on reducing energy use in the built environment. Before the Alliance, he worked for the Maryland Energy Administration, the state energy office, on numerous legislative and regulatory issues and developed and presented testimony before the Maryland General Assembly and the Maryland Public Service Commission.

Prior to entering the energy and environment field, Mr. Lucas was a manager at Accenture, a leading consulting firm. Mr. Lucas implemented enterprise resource planning software for Fortune 500 companies in industries such as consumer electronics, oil and gas, and manufacturing.

AREAS OF EXPERTISE

- Renewable Energy Policy Analysis: extensive experience analyzing renewable energy policy issues and communicating results to both expert and general audiences.
- Energy Efficiency Policy Analysis: detailed understanding of energy efficiency policies, including the development of potential studies and utility efficiency program design and implementation.
- Quantitative Analysis: deep expertise in quantitative analysis across a broad range of topics including analyzing financial and operational data sets, constructing models to explore electricity industry data, and incorporating original analysis into expert witness testimony.
- Energy Markets: studies interaction of renewable energy and energy efficiency policies with wholesale market operation and price impacts.
- Legislative Analysis: reviews legislation related to energy issues to discern potential impacts on markets, utilities, and customers.

EDUCATION

Mr. Lucas holds a Masters of Business Administration from the University of North Carolina, Kenan-Flagler Business School (2009) and a Bachelor of Science in Engineering, Mechanical Engineering from Princeton University (1998).

ACADEMIC HONORS

- Beta Gamma Sigma Honor Society
- Paul Fulton Fellowship, Kenan-Flagler Business School
- Graduated *cum laude* from Princeton University

EXPERT WITNESS TESTIMONY

Public Utilities Commission of the State of Colorado

- Docket 17A-0797E – *Public Service Company - Accelerated Depreciation - AD/RR*
    - Advocating for appropriate structure to utilize renewable energy funds to support the early retirement of coal facilities and to continue to support distributed resources
- Docket 19A-0369E – *In the Matter of The Application of Public Service Company of Colorado For Approval of Its 2020-2021 Renewable Energy Compliance Plan*
    - Advocating for changes to better support solar and solar plus storage installations
- Docket 19AL-0687E - *In the Matter Of Advice No. 1814-Electric of Public Service Company of Colorado to Revise its Colorado P.U.C. No. 8 – Electric Tariff to Reflect a Modified Schedule RE-TOU and Related Tariff Changes to be Effective on Thirty-Days' Notice*
    - Designed and advocated for new data-based default time of use rate

Maryland Public Service Commission

- Case 9153, 9154, 9155, 9156, 9157, 9362 - *In the Matter Of Maryland Utility Efficiency, Conservation And Demand Response Programs Pursuant To The Empower Maryland Energy Efficiency Act Of 2008*
    - Multiple filings regarding the design and implementation of Maryland's energy efficiency portfolio standard
- Case 9271 - *In re the Merger of Exelon Corp. & Constellation Energy Grp., Inc.*
    - Analysis of renewable energy commitments in merger proposal
- Case 9311 - *In re the Application of Potomac Elec. Power Co. for an Increase in its Retail Rates for the Distrib. of Elec. Energy*
    - Supporting the implementation of a limited cost tracker to accelerate reliability investments after 2012 Derecho
- Case 9326 - *In re the Application of Balt. Gas & Elec. Co. for Adjustments to its Elec. & Gas Base Rates.*
    - Supporting the implementation of a limited cost tracker to accelerate reliability investments after 2012 Derecho
- Case 9361 - *In re the Matter of the Merger of Exelon Corporation and Pepco Holdings, Inc.*
    - Policy analysis of merger proposal

Michigan Public Service Commission

- Case U-18419 – *In the matter of the application of DTE ELECTRIC COMPANY for approval of Certificates of Necessity pursuant to MCL 460.6s, as amended, in connection with the addition of a natural gas combined cycle generating facility to its generation fleet and for related accounting and ratemaking authorizations.*
    - Arguing against DTE Electric's proposal to construct a new natural gas combined cycle generating facility and instead meet its future capacity and energy needs with a distributed portfolio of solar, wind, energy efficiency, and demand response.
- Case U-20162 – *In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority*
    - Arguing against DTE Electric's proposal for a net energy metering successor tariff that improperly undervalued the contribution of distributed solar.
- Case U-20165 - *In the matter of the application of Consumers Energy Company for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief.*
    - Discussing Consumers Energy Company's integrated resource plan, arguing for advancing the deployment of solar to meet its capacity requirements, arguing against Consumers' proposed financial compensation mechanism for third-party PPA contracts, supporting a robust PURPA market, and supporting transparent and equitable competitive procurement guidelines.
- Case U-20471 - *In the matter of the Application of DTE Electric Company for approval of its integrated resource plan pursuant to MCL 460.6t, and for other relief.*
    - Evaluating DTE's integrated resource plan, arguing for the Company to modify its modeling assumptions for solar, analyzing the operation and reliability of DTE's aging peaker fleet, demonstrating that solar and solar plus storage could replace some of DTE's peakers, advocating for robust competition and third-party access to new resources.

Public Utility Commission of Nevada

- Docket Nos. 17-06003 & 17-06004 Phase III – Rate Design – *Application of Nevada Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto.*
    - Arguing against Nevada Power Company's proposal to increase fixed customer charge

Public Utility Commission of Texas

- Docket 46831 – *Application of El Paso Electric Company to change rates*
    - Critiquing El Paso Electric's proposal to implement a three-part rate for residential and small commercial net metered customers

Question:

47. Refer to Exhibit A-21 (JCA-7). Please produce all data and information that was provided to Brattle for the purposes of conducting the analysis of Consumers' Standby Customers, including the data provided for Residential NEM Customers.

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request for the reason that it seeks data and information protected from disclosure under the Company's Customer Data Privacy tariffs, as approved by the Michigan Public Service Commission. Subject to this objection, and without waiving it, Consumers Energy Company answers as follows:

Attached are the files provided to Brattle in support of Exhibit A-21 (JCA-7) and the reports provided in response to U20697-ELPC-CE-110.

Only the aggregated meter data for residential and business customers with self-generation under 550 kw is being made available. Without such limitations, providing to ELPC the individual customer meter data and account information that was included in the files provided to Brattle would violate the Company's Customer Data Privacy tariffs. The hourly meter data, and the relevant customer information necessary to analyze the meter data, is either tracked separately or generated in separate files by the Company's IT system. Therefore, customer identifiable information, such as contract account, is necessary to connect the data sets. Connecting the data sets was a task that Brattle performed as a contractor of the Company and as part of the analytic services described in the Residential report, page 7, and Secondary/Primary report, page 6.

The meter data used for the development of Exhibit A-21 (JCA-7) is being provided after the Company manually replaced the contract account information for each customer with a simple numerical sequence. This numerical sequence was maintained across the data sets so that they could still be connected for an analysis.

JOSNELLY C APONTE
April 3, 2020

Rates & Regulation

Revised Response:

The 2018 meter data available for customers participating in the Company's net metering program is provided as an attachment to this updated response. The data for residential customers is captured in separate files from commercial & industrial customers.

- Inflow is in files labeled as "delivered" (power delivered to customer, ignoring any received power)
- Outflow is in files labeled as "received" (power received from customer, ignoring any delivered power)

The data attributes within the files are the following:

- Unit of Measure: KWh
- Time stamp: EST
- Hour ending intervals. When the files say 1/1/2018 INT01, this means that the data represents the kWh used between 1/1/2018 00:00:00 and 1/1/2018 00:59:59 and so on.
- Intervals are not cumulative. If an interval is missing, the energy is not captured in the following period.
- The identifier is a unique 9-letter code that's consistent for each customer across files. This code can be used to reference a particular customer in any follow up request.

The Company used an updated process to gather the information requested than what was used for providing information to Brattle. Although the Company does not believe the results will differ much, it is possible that the individual account level data provided for 2018 in response to this discovery may not perfectly aggregate to what Brattle used for the DG analysis.

JOSNELLY C APONTE
May 19, 2020

Rates & Regulation

Question:

172. What costs, if any, are allocated based on the 1CP cost allocator?

Response:

The Company does not use the single coincident peak method to allocate costs.

JOSNELLY C APONTE
June 1, 2020

Rates & Regulation

Question:

50. Reference Mr. Miller's testimony at page 23. Has Mr. Miller conducted any analysis of the cost of a NEM customers cost causation for their use of the grid? Is Mr. Miller aware of any such analysis conducted by the Company or at the Company's request?

Response:

As discussed on pages 26 and 27 of my direct testimony, the Company asked the Brattle Group to evaluate the cost of serving standby customers. Although I did not perform this study, the results of that study are described on page 31 of Company witness Aponte's testimony and indicate that the per unit cost of serving customers with distributed generation are between 20% and 50% higher than that of other customers.

Hubert W. Miller III

HUBERT W. MILLER III
March 30, 2020

Rates & Regulation Department

Question:

178. Does the Company's COSS and load studies use actual demand or ratcheted billing demand?

Response:

The Company's COSS and load studies use actual demand.

JOSNELLY C APONTE
June 9, 2020

Rates & Regulation

Question:

169. What is the proper method for accounting for very large customer growth in a test year for a customer class? For instance, if the Primary Time of Use Pilot GPTU class had increased from 300 customer to 1,032 customers during the 2018 test year, what, if any, adjustments need to be made to either the COSS model or to the underlying GPTU data that was input into the COSS model? Should the beginning, average, or ending number of customers be used?

Response:

For development of the historic load profiles, the Company uses the data from Annual Report of Consumers Energy Company to the Michigan Public Service Commission for the year ended December 31, 2018, page 304 and 304.1, column (b), which reflects "Average Number of Customers". For the test year, the Company uses the projections sponsored by Company witness Eugene M. Breuring (Please see response to request 20697-ELPC-CE-1254).

JOSNELLY C APONTE
June 1, 2020

Rates & Regulation

Question:

166. Confirm that the annual sales value from the “Sales & Revenue” tab is used in the “Load Data & TY Sales” tab as the basis to calculate the other load data in rows 137 to 166 (e.g. the 12 CP values, the sales by peak/off peak, the class peak, etc.) by taking the “Sales including ROA” row 163 and multiplying by the 3 year average ratios found in rows 104 to 133. If deny, please explain.

Response:

The Company applies the test year sales in the “Sales & Revenue” tab to the three-year average of historic profiles in the “Load Data & TY Sales” tab to develop the test year allocation schedules.

JOSNELLY C APONTE
June 1, 2020

Rates & Regulation

Question:

Please refer to the Company's response to ELPC-CE-110 regarding the various Brattle studies on standby customers over 550 kW, residential NEM customers, and secondary and primary NEM customers.

99. Do any of the Brattle studies credit customers for the outflow energy they send back on to the grid? If so, please indicate how this credit was incorporated into the analyses. If not, please explain why no credit was given for the outflow energy.

Response:

No. The studies performed by Brattle did not credit customers for the outflow energy they send back on to the grid. Instead, the Company's proposal for the Distributed Generation program includes an outflow bill credit that compensates customers for the generation not used on site and exported to the utility.

JOSNELLY C APONTE
May 26, 2020

Rates & Regulation

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	)))))	Case No. U-20697

EXHIBITS OF

CLAUDINE Y. CUSTODIO

ON BEHALF OF

THE ECOLOGY CENTER
THE ENVIRONMENTAL LAW & POLICY CENTER
THE GREAT LAKES RENEWABLE ENERGY ASSOCIATION
THE SOLAR ENERGY INDUSTRIES ASSOCIATION
AND VOTE SOLAR

June 24, 2020

Claudine Y. Custodio, E.I.T.
claudine@votesolar.org
Office: 360 22nd St, Suite 730, Oakland, CA 94612

Education

M.S. Civil and Environmental Engineer; Energy, Climate, and Civil Infrastructure Program
University of California at Berkeley, Berkeley, CA

B.S. Environmental Resources Engineering; Emphasis on Energy Resources, (ABET Accredited)
Humboldt State University, Arcata, CA
Graduated Cum Laude, Passed Fundamentals of Engineering Exam (EIT)—May, 2011

Technical Skills

Advanced Excel, Microsoft Office Suite (Excel, Word, Powerpoint), Google Drive & Docs, Github, Python, Javascript, SQL, HTML & CSS, FORTRAN 90, Machine Learning, MATLAB, Wix, Wordpress, ActionNetwork, Zoom, Slack

Experience

Regulatory Research Manager — **July 2019**
Vote Solar — **Riverside, CA**

- Coordinate with Regional Directors on rate cases related to solar distribution
- Analyze and summarize customer data using machine-learning techniques in Python
- Draft testimony and prepare workpapers

Steering Committee Member — **February 2018**
350 Riverside — **Riverside, CA**

- Facilitate skill sharing and training to members of the California 350.org local groups
- Write, research, and edit articles for monthly newsletter distributed to 100 local group leaders
- Discuss and advocate for legislation such as CA 100% Clean Energy Act with elected officials
- Manage 400-member mailing list and send monthly reminders about meetings and local events
- Create and manage website (Wordpress) and social media accounts (Facebook and Twitter)

Senior Research Associate — **June 2012 – September 2015**
Lawrence Berkeley National Lab — **Berkeley, CA**

- Streamline cleaning and formatting data from Energy Star Portfolio Manager, CBES, RECS, city and local government portfolios
- Diagnose building energy efficiency using benchmarking and statistical models in Python
- Assess energy and lighting data from numerous monitoring points and calculated retrofit energy savings using Excel
- Design & implement occupant survey and conducted interviews with facility managers
- Collaborated on technical documentation and project reports with team members using Google Docs and Microsoft Office
- Set up long-term monitoring experiments: installed light monitoring and remote monitoring equipment & upload software in partner project buildings

Graduate Student Instructor — **Fall 2011**
UC Berkeley Physics Department — **Berkeley, CA**

- Prepared weekly supplemental lessons for a class of 20 students in Introductory Physics
- Facilitated laboratory work once a week

Research Intern **Summer 2008**
Center for Environmental Research and Technology **Riverside, CA**

- ◆ Assisted graduate and PhD students in literature search
- ◆ Operated a batch processor and gas chromatographer

WORLD OF WATER

October 13, 2014

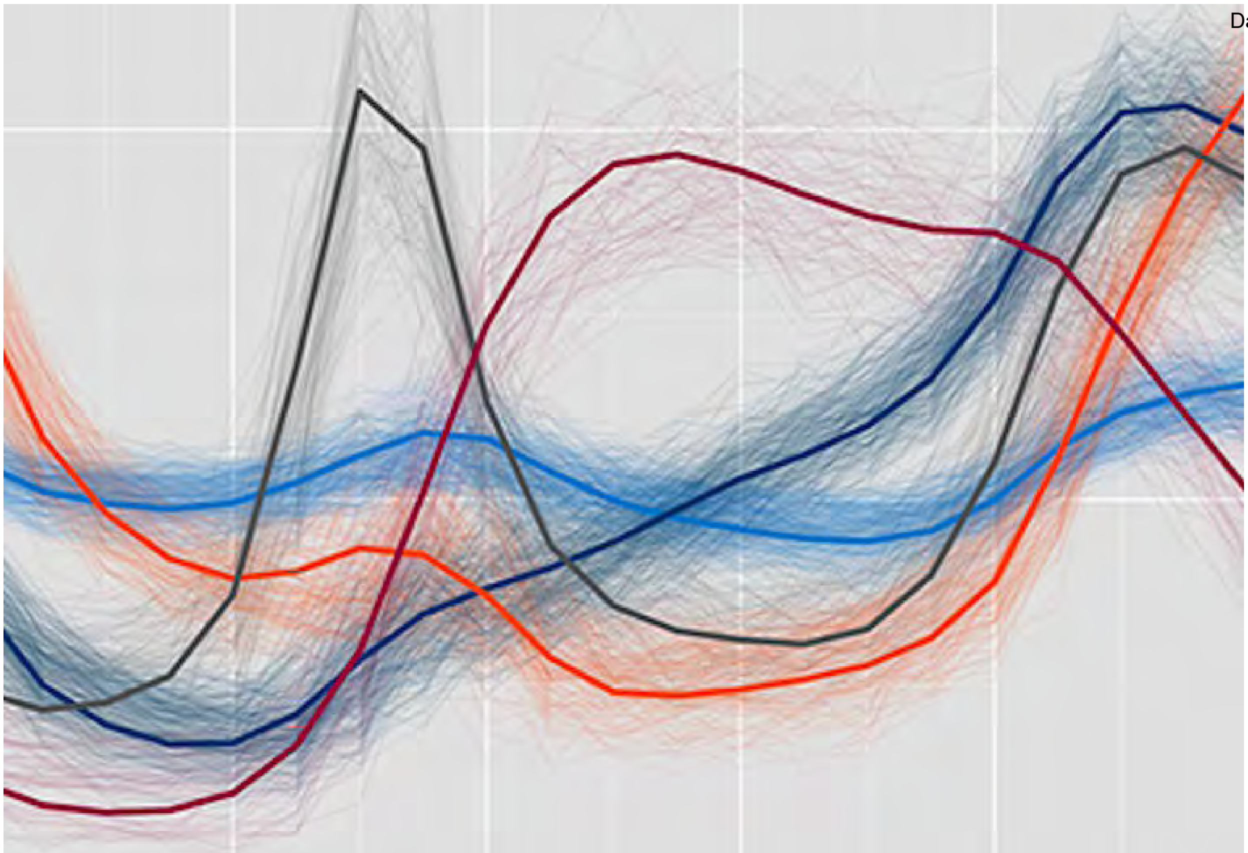
We plotted 812,000 energy usage curves on top of each other. This is the powerful insight we discovered.

Barry Fischer

We all know that not everyone uses energy the same way.

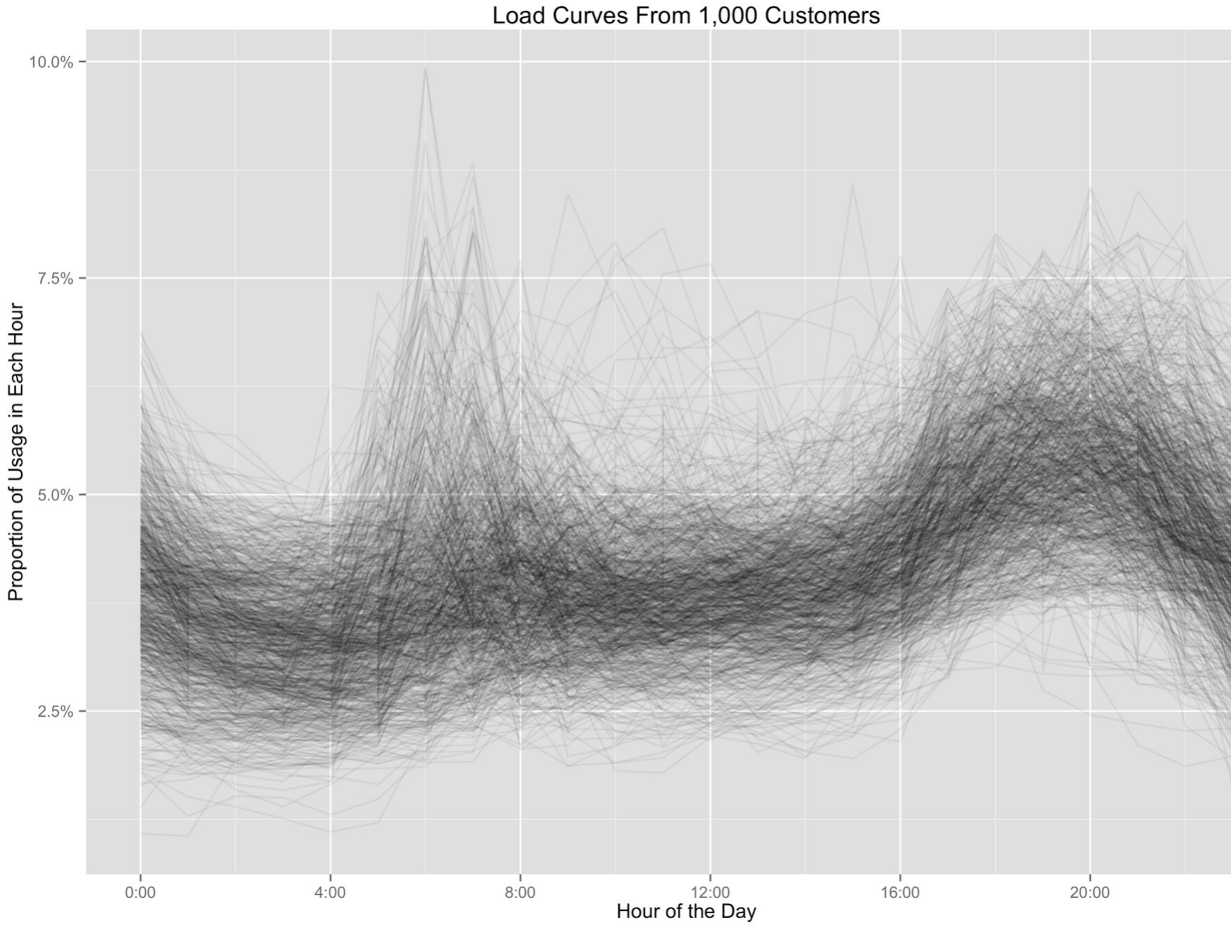
Some of us shut off all the lights when we leave in the morning until we get home at 6 p.m., others crank up the AC in the mid-afternoon. But, how does a utility go about uncovering these kinds of patterns for hundreds of thousands or millions of customers?

It starts with data of course. By combining detailed energy data along multiple dimensions — such as time, geography, and weather — you can then tease out key similarities and differences among types of energy users.



Working to extract insights from all those data is exciting. But to an untrained eye, it can also be overwhelming.

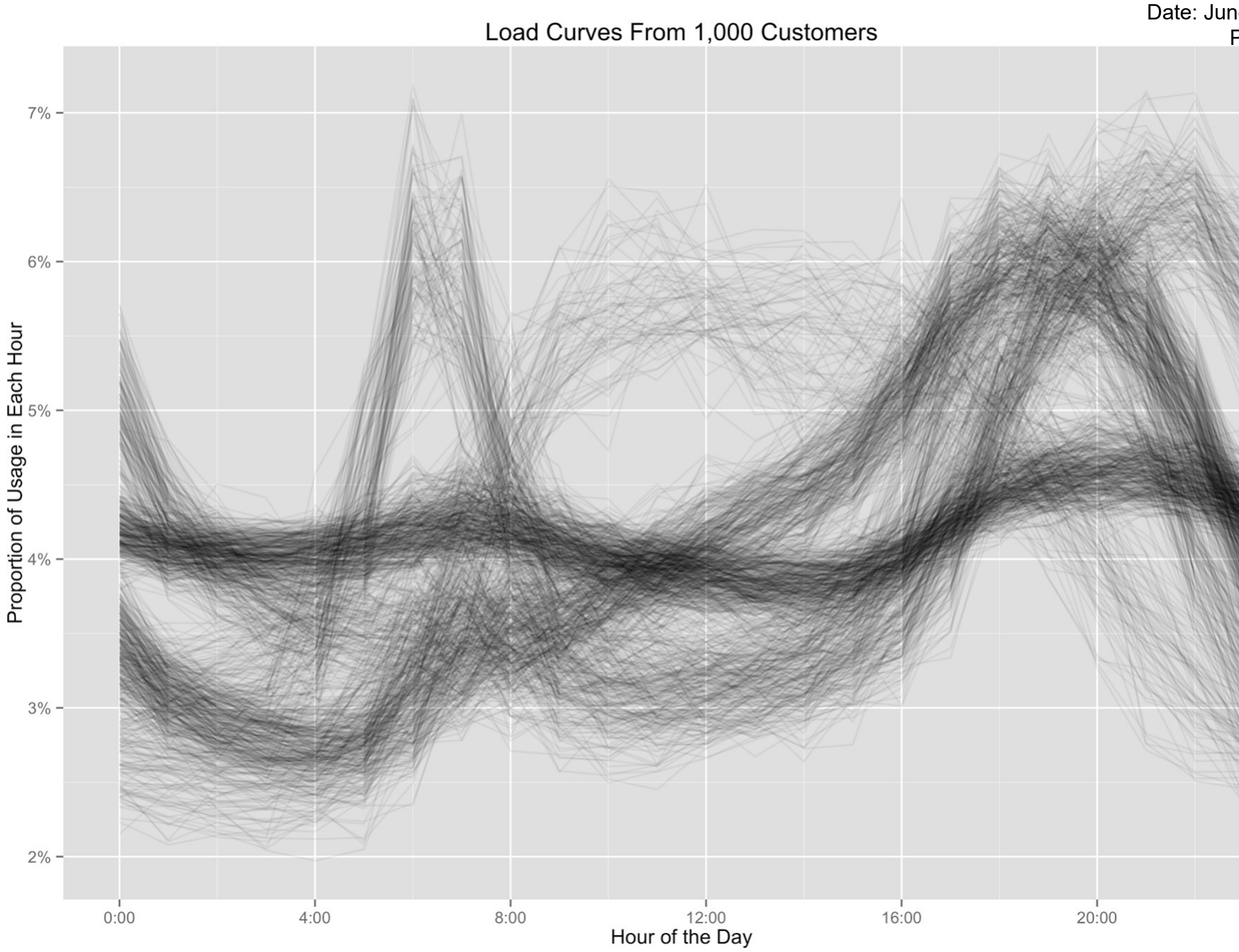
A quick glance at the below graph illustrates the point. The graph displays weather-normalized hourly electricity consumption from a random sample of 1,000 residential utility customers, for a typical weekday. It's not hard for an onlooker to be intimidated by the blob-like result.



Source: Opower (2014)

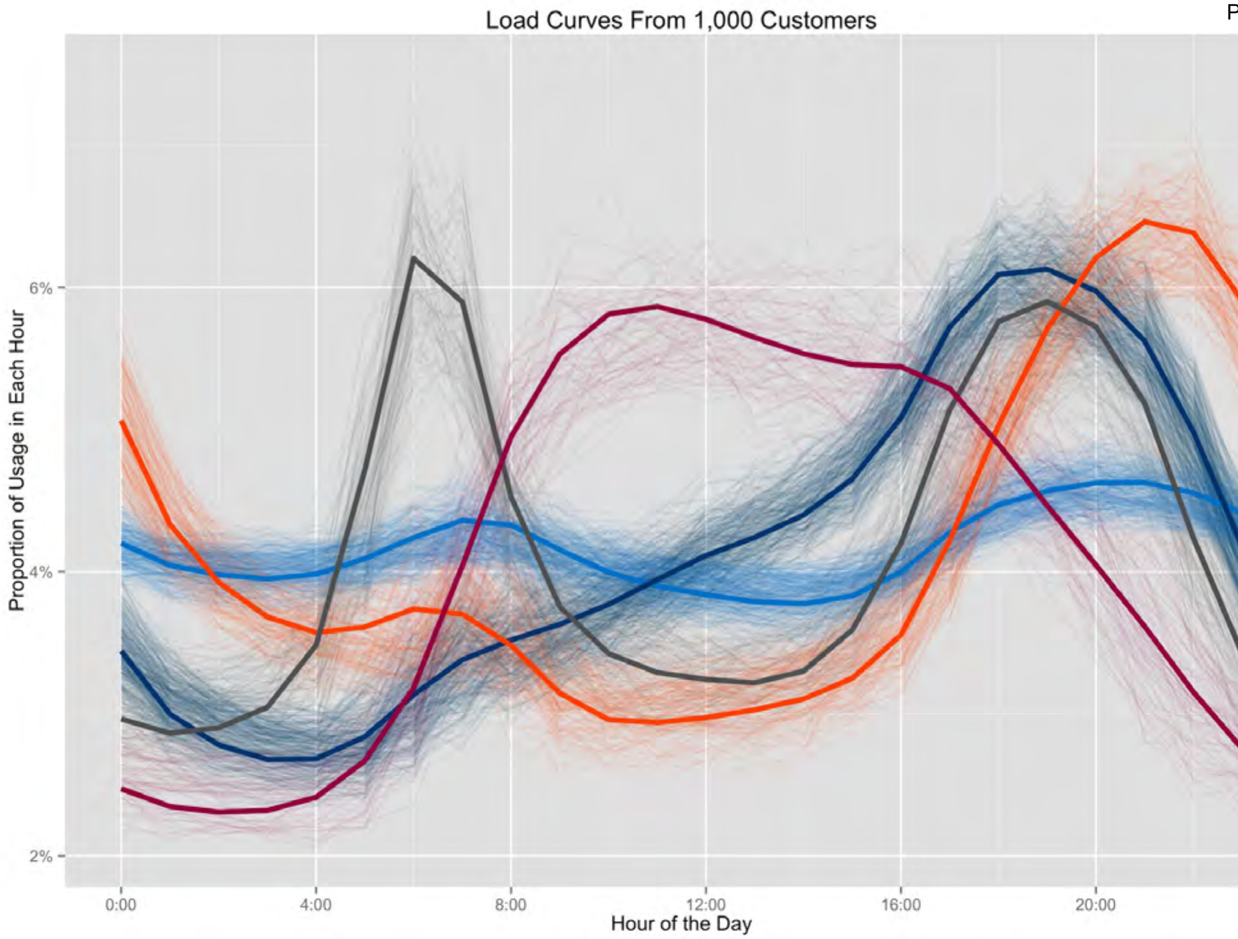
But with some clever machine learning logic and the right big data architecture (our data warehousing and processing frameworks run on tools like Hadoop and MapReduce), it's not long before you can start finding signals in the noise. In recent months, we did so by analyzing usage data from 812,000 utility customers (for simplicity, a fraction of that dataset is displayed here) in 3 major US metropolitan regions. By applying advanced clustering techniques, such as vector quantization, we were able to identify a series of recurring patterns across the usage data.

Specifically, based on our statistical clustering, you can see around five distinct hourly electric load patterns start to emerge from what *used to be* a mere jumble. Each of these well-defined patterns can be described as a particular "load archetype." There are about five weekday load archetypes discernible in the below graph.



Source: Opower (2014)

A little color can help further illuminate different load archetypes extracted from the dataset. For example, below you can transparently distinguish between distinct categories of customers, such as those whose usage spikes in the morning ("the coffee makers" - black curve) versus those whose usage reaches a maximum around 5pm ("the late afternoon peakers" - dark blue curve).



Source: Opower (2014)

An important discovery of our statistical analysis is that **constructing load archetypes at scale — and classifying customers within them — is not only readily possible; it can also unlock new opportunities for utilities and their customers.**

Utilities around the world rely on Opower's customer engagement platform to use data insights, like load curve archetypes, to deliver the right message at the right time to the right customer. By coupling these data insights with personalized communications, utilities can improve the customer experience while at the same time boosting the impact and cost-effectiveness of their programs.

For example, if a utility can easily and quickly identify the customers in a region who most closely fall into a "late afternoon peaker" load archetype, then the utility can take a more targeted and direct approach to delivering peak reduction programs like behavioral demand response or smart thermostat management. In such a scenario, a utility saves time and money by focusing their efforts on customers who are best positioned to reduce peak load, and all customers are happier because they're receiving offers that are most relevant to them (and not receiving offers that aren't relevant).

Or imagine a load archetype that corresponds to electric vehicle owners who tend to charge their cars during the daytime. A utility could identify customers whose usage behavior falls within that archetype class, and deliver automated targeted outreach to them about special rate plans that incentivize car charging after midnight (when the grid has more excess capacity).

Load archetypes and the market segmentation possibilities that flow from it are just a couple ways that utilities can infuse data-driven personalization into the utility customer experience. For more on how advanced data insights are creating next-generation opportunities for utilities and their customers, check out this nifty disaggregation algorithm that is unlocking the power of the smart grid.

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A clustering approach to domestic electricity load profile characterisation using smart metering data

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HIGHLIGHTS

- We characterise diurnal, intra-daily, seasonal and between customer electricity use.
- A series of profile classes reflective of home electricity use are constructed.
- We examine the influence of household characteristics on patterns of electricity use.

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ABSTRACT

The availability of increasing amounts of data to electricity utilities through the implementation of domestic smart metering campaigns has meant that traditional ways of analysing meter reading information such as descriptive statistics has become increasingly difficult. Key characteristic information to the data is often lost, particularly when averaging or aggregation processes are applied. Therefore, other methods of analysing data need to be used so that this information is not lost. One such method which lends itself to analysing large amounts of information is data mining. This allows for the data to be segmented before such aggregation processes are applied. Moreover, segmentation allows for dimension reduction thus enabling easier manipulation of the data.

Clustering methods have been used in the electricity industry for some time. However, their use at a domestic level has been somewhat limited to date. This paper investigates three of the most widely used unsupervised clustering methods: k-means, k-medoid and Self Organising Maps (SOM). The best performing technique is then evaluated in order to segment individual households into clusters based on their pattern of electricity use across the day. The process is repeated for each day over a six month period in order to characterise the diurnal, intra-daily and seasonal variations of domestic electricity demand. Based on these results a series of Profile Classes (PC's) are presented that represent common patterns of electricity use within the home. Finally, each PC is linked to household characteristics by applying a multi-nominal logistic regression to the data. As a result, households and the manner with which they use electricity in the home can be characterised based on individual customer attributes.

1. Introduction

Throughout the European Union, there has been a move towards smarter electricity networks, where increased visibility over electricity generation and consumption has been achieved with the installation of Advanced Metering Infrastructure (AMI). Smart metering is part of this and is seen as a necessary component to achieve EU 20-20-20 energy policy goals by the year 2020: to cut greenhouse gas emissions by 20%, to improve energy efficiency by 20% and for 20% of EU energy demand to come from renewable energy resources [1].

In recent years, smart meter installations have increased worldwide in a bid to modernise aging electricity networks [2]. Furthermore, improvements in the regulatory environment, particularly within the residential sector in Europe has resulted in a number of smart metering pilot programmes [3]. As a consequence, a wealth of new data exists for utilities, giving detailed electricity consumption at increased granularity for a large number of customers within the residential sector [4]. The availability of this source of data can potentially be used by utilities to create customised electricity load Profile Classes (PC) and can assist in areas such

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as: improved load planning and forecasting; Time of Use (ToU) tariff design; electricity settlement; and Demand Side Management (DSM) strategies [5].

This paper presents a new methodology for electricity load profile characterisation. In doing so, a series of domestic electricity PC's are constructed that are reflective of the varied manner with which electricity is used within the home. Currently, PC's are derived based on aggregating many dissimilar patterns of electricity use together [6]. The application of this type of approach, where individual households which may use electricity in very different ways get lumped together, results in the formation of highly aggregated load profiles. However, in reality this is not a true reflection of how electricity is actually consumed and which can change considerably between different customers [7]. The paper proposes an alternative method which uses clustering to identify similar patterns of electricity use before any aggregation processes are applied. In this way, information pertaining to the electricity load profile shape is not lost. In addition, the paper also presents a method of linking PC's to individual customers so that a household and the manner with which they use electricity within the home can be characterised based on their individual customer attributes.

The paper is structured as follows. Section 2 illustrates existing methods used for electricity load profile characterisation and their limitations in dealing with smart metering data. Section 3 presents the structure of the data on which the analysis was carried out. Section 4 provides the methodological approach for the paper which is divided into three distinct sections: clustering; electricity load profile characterisation; and customer profile classification. Section 5 presents and discusses results with Section 6 containing concluding remarks.

2. Domestic electricity load profile characterisation

Based on the literature, existing methods used to characterise domestic electricity use can generally be divided into four categories: statistical; engineering; time series and clustering. Statistical methods have been widely used in de-regulated electricity markets to form standard load PC's [6]. Standard load PC's are used for the purposes of settlement and provide an estimate as to the quantity and Time of Use (ToU) of electricity being used. A series of PC's are produced for different segments of the market (e.g. residential, commercial, industrial) and are derived based on the average for all customers contained within a single customer class [8]. The UK electricity market has two domestic PC's; Unrestricted and Economy 7. In Ireland, four PC's exist for the domestic sector; 24 h and Night Saver which are split by urban and rural divide [9]. Although PC's are suitable for the purposes of settlement, in reality they are not reflective of how electricity is actually consumed within the home on a daily basis and merely represent the average for all customers contained within the same class. Other statistical techniques consist of using descriptive statistics and probability [10–16] as well as regression [17–22] to describe electricity use within the home. Similar to that stated above, these methods produce highly diversified load profile shapes, a result of combining many dissimilar patterns of electricity use together [10].

Engineering approaches to domestic load profile characterisation are varied but generally characterise electricity use as a function of parameters such as occupancy or appliance ownership [23–28]. These methods are considered to be a bottom up approach where multiple profiles are constructed for different households and therefore do not suffer from the same problem highlighted above for statistical approaches. However, engineering methods are difficult to generalise and require detailed knowledge of household occupant and appliance Time Use (TU) [29]. In contrast time series approaches have been limited in their application to domestic households, but this is most likely due to a historical lack of available data for the sector [7]. The methods have been used extensively to describe electricity use at a Transmission System Operator (TSO) level [30–34]. However, these approaches suffer from a similar problem to that highlighted above for statistical techniques when many dissimilar profiles are aggregated together resulting in diversified electricity load profile shapes [35].

Finally data mining techniques such as cluster analysis have been used to group customers which exhibit similar electrical behaviour through ToU smart meter data, but have mostly been applied at an aggregated level [36–38]. Furthermore, customers have also been clustered based on aggregated parameter values such as annual electricity use or features relating to the electricity load profile shape (e.g. load factor) [39,40]. Similarly, load profiles have been constructed for commercial, industrial and mostly aggregated residential customers based on clustering methods: Self Organising Maps (SOM), k-means and Follow the Leader [41–43]. In particular, one large study of approximately 3000 residential customers was monitored over a period of a single year and used methods: SOM; k-means; and hierarchical to cluster and construct load profiles [44]. However, the analysis was restricted to only a small portion of the time series (5%) due to computational demands. Clustering methods do not suffer from many of the problems highlighted above particularly when it is applied prior to carrying out any statistical analysis. Furthermore with improvements in computer hardware tasks such as clustering, which can be computationally intensive have become easier to implement.

This paper fills a gap in the literature by clustering based on ToU for a large sample of residential customers over a period of six months. This allows for load PC's to be derived based on individual patterns of electricity use within the home over this period and does not suffer from some of the same aggregation problems highlighted above. Furthermore, as the entire dataset is clustered, diurnal, intra-daily and seasonal patterns to electricity use can be characterised, as well as between customer variations. Moreover, as dwelling, occupant and appliance characteristics are correlated with each PC's it also provides a method of assigning patterns of electricity use to individual customers. Finally, as the sample size is relatively large the PC's can be considered to be representative of the wider population in Ireland. A similar method could also be used in other electricity markets outside of Ireland.

3. Data structure

The smart metering trial carried out by Commission for Energy Regulation (CER) provided the necessary information to segment the domestic electricity market in Ireland based on ToU [45]. The trial was conducted between 2009 and 2010 and consisted of installing smart meters in over 4000 residential dwellings in Ireland. Electricity demand at half hourly intervals as well as detailed information on dwelling, occupant and appliance characteristics for a representative sample of dwellings in Ireland was recorded [46,47]. The data provided was in anonymised format in order to protect personnel and confidential information relating to the customer.

The data used in the analysis was taken over the period 1st July to 31st December 2009. The sample size was trimmed to 3941 customers in total on account of missing information due to technology communication problems. Matlab and its respective statistical (ver. 7.3) and neural network toolboxes (ver. 6.0.4) were used to carry out manipulation and analysis of the data [48]. SPSS was used to analyse dwelling, occupant and appliance characterises with a unique service ID providing the link between the two software programs [49].

4. Methodology

The smart metering data described in Section 3 was used to segment customers based on patterns of electricity use within the home using clustering. A series of PC's were produced and linked to dwelling and household characteristics, such as Head of Household (HoH) age and Household (HH) composition, through multi-nominal logistic regression. The methodology used is shown in Fig. 1 and can be divided into three distinct parts: clustering; electricity load PC characterisation; customer PC classification.

4.1. Stage 1 – Clustering

Firstly, each clustering technique was evaluated as to the suitability for segmenting the data. Three of the most widely used clustering algorithms for the electricity industry were investigated: k-means; k-medoid and Self Organising Maps (SOM) [50–52,42]. Secondly, a suitable number of clusters was identified to segment the data. In both cases, a Davies–Bouldin (DB) validity index was used to identify the most suitable clustering method and appropriate number of clusters [53]. This is a commonly used measure to evaluate how well a dataset has been segmented [54]. The index was evaluated over three separate random days and the average taken. This was done so as to ensure that the index was not calculated against an atypical day. Finally, once a suitable clustering method and number of clusters was identified, each day was clustered separately on a 24 h basis over a six month period. This ensures that the diurnal, intra-daily and seasonality components to electricity use within the home can be captured by the characterisation process.

4.2. Stage 2 – Electricity load PC characterisation

Electricity demand for an individual cluster on a particular day was averaged (as it represents a similar pattern of electricity use) to create a daily electricity load profile for a cluster. Clusters that were small in size and that differed slightly in terms of both magnitude and timing of electricity use were combined together (thus reducing the number of similar shaped profiles) to produce a series of PC's. This results in a vector size of 48 $\times$ 184 data points for each class representing average half hourly electricity use for each day over a six month period respectively. Fig. 2 shows an illustration of a single customer and the manner in which PC's are used to characterise daily electricity use within the home.

4.3. Stage 3 – Customer PC classification

The PC that each customer used on a particular day was recorded in a Customer Class Index (CCI). The data structure of the CCI index can be seen on the right hand side of Fig. 1. As customers tend to use electricity differently on a daily basis, as was shown in Fig. 2, often customers use multiple PC's over a period. Therefore, the statistical *Mode* of the CCI index was used to determine which PC each customer used for the majority of the time across the six month period. This was done so that a multi-nominal logistic regression could be used to determine the likelihood of a customer with individual characteristics (e.g. dwelling type, number of bedrooms, etc.) using a particular PC.

Eq. (1) describes the likelihood or odds ratio *Exp* [*B*] of using a particular PC where: β_0 is a constant; $\beta_1, \beta_2, \ldots, \beta_n$ are the regression coefficients that explain the association of each explanatory variable $X_1, X_2, \ldots, X_n$ (customer characteristics) on the response variable (PC). $P(x)$ describes the probability of using a particular PC when compared against a reference class $p'(x)$ [55]. The explanatory variables were chosen based on a linear multivariate regression model (shown in a previous paper) which described the key characteristics that influenced electricity use within the home [56].

$$Exp[B](odds\ ratio) = \log\left[\frac{p(x)}{p'x}\right] = \beta_0 + \beta_1 X_1 + \beta_2 X_2 + \cdots + \beta_n X_n \quad (1)$$

Table 1 shows the sample size for each explanatory variable with base categories highlighted in bold italics. For electric water heating and cooking the base category was households that use non-electric means to heat water and cook. Similarly for each appliance type the

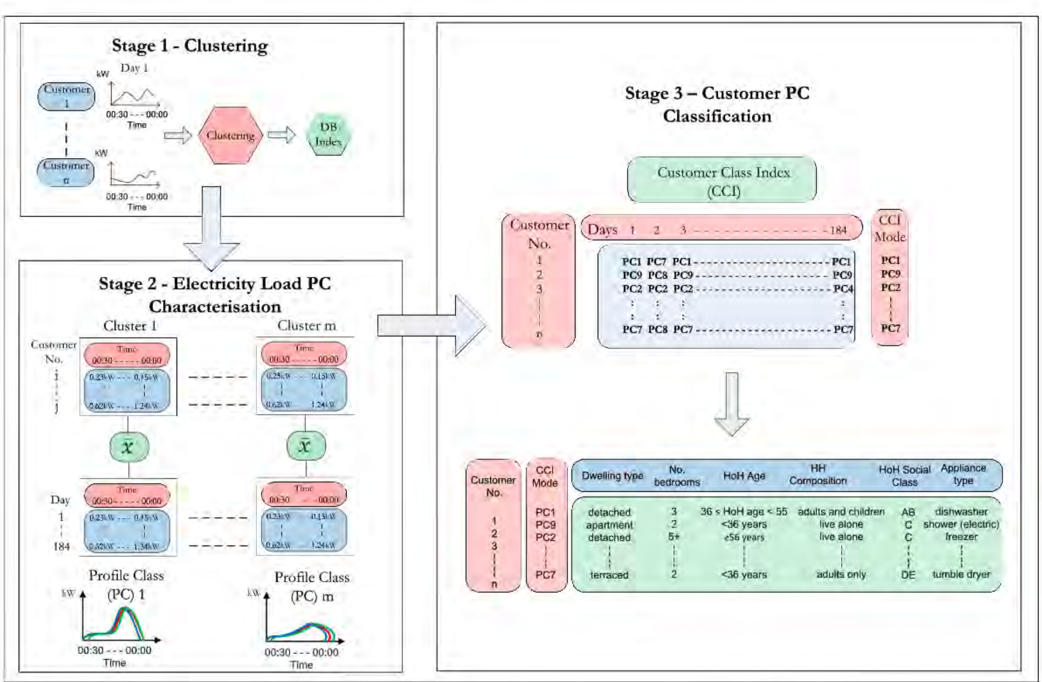

Fig. 1. Methodological approach to electricity load profile characterisation through clustering: Stages 1, 2 and 3 are described in Sections 4.1–4.3 respectively.

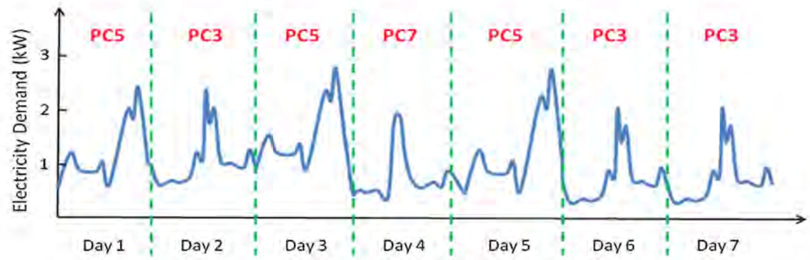

Fig. 2. Illustration of a single customer's characterised electricity use within the home using Profile Classes (PC).

Table 1
Dwelling, occupant and appliance characteristic sample sizes.

Explanatory variable	Explanatory variable explanation	Sample size (N)
Dwelling type – detached	Dwelling is detached (includes bungalows)	2068
Dwelling type – semi-detached	Dwelling is semi-detached	1230
Dwelling type – terraced	Dwelling is terraced	569
Dwelling type – apartment	Dwelling is apartment	67
No. of bedrooms – 1	Dwelling has one bedroom	42
No. of bedrooms – 2	Dwelling has two bedrooms	333
No. of bedrooms – 3	Dwelling has three bedrooms	1748
No. of bedrooms – 4	Dwelling has four bedrooms	1367
No. of bedrooms – 5+	Dwelling has five plus bedrooms	451
HoH age < 36 years	Head of household age less than 36 years	390
HoH age betw. 36 & 55 years	Head of household age between 36 and 55	1776
HoH age ⩾ 56 years	Head of household age above 56	1753
HH comp. – live alone	Household composition – live alone	756
HH comp. – with adults only	Household composition – live with adults only	2064
HH comp. – with adults and children	Household composition – live with adults and children	1121
HoH social class – AB	High and intermediate managerial, administrative or professional	593
HoH social class – C	Supervisory and clerical and junior managerial, skilled manual workers	1697
HoH social class – DE	Semi-skilled and unskilled manual workers, state pensioners, unemployed	1505
HoH social class – F	Farmers	107
Water heating – electric	Water is heated by electricity	2237
Cooking type – electric	Cooking is mostly done by electricity	2749
Washing machine	Appliance type washing machine is present	3873
Tumble dryer	Appliance type tumble dryer is present	2693
Dishwasher	Appliance type dishwasher is present	2638
Shower (instant)	Appliance type shower (instant) is present	2726
Shower (pumped)	Appliance type shower (pumped) is present	1150
Electrical cooker	Appliance type electrical cooker is present	3039
Heater (plug in convective)	Appliance type heater is present	1199
Freezer (stand alone)	Appliance type freezer is present	1961
Water pump	Appliance type water pump is present	772
Immersion	Appliance type immersion is present	3022
TV < 21 in.	Appliance type TV < 21 in. is present	2583
TV > 21 in.	Appliance type TV > 21 in. is present	3309
Computer (desktop)	Appliance type computer (desktop) is present	1864
Computer (laptop)	Appliance type computer (laptop) is present	2107
Game consoles	Appliance type game console is present	1310

base category was compared against households that do not own that particular appliance.

5. Results and discussion

The following section presents results and discussion for each stage of the methodology described in Section 4.

5.1. Clustering

The DB validity index was calculated for each clustering technique (k-means, k-medoid, SOM) and for varying number of clusters (2–16) over three separate random days with the average shown in Fig. 3. SOM showed a consistently lower DB index overall across varying number of clusters, and therefore was selected to segment the data further. The optimal number of segments used to divide the data was chosen at between 8 and 10 clusters as after this point any further decrease in DB index was minimal. It is important to note that the DB index was lowest overall for two clusters, however, as this would lead to highly aggregated PC's like that described in Section 2, more than two segments was sought.

The dataset was divided into nine clusters based on 3 × 3 hexagonal lattice structure shown on the left hand side of Fig. 4. Cluster centres are shown to be visually separated by Euclidean distance indicated by different colours. The brighter colours show clusters that are close together whereas the darker colours represent cluster centres that are further apart. It can be seen that clusters c6 and c9 are most similar to each other compared to any other cluster pair.

The cluster size is shown as a percentage of total sample size in Fig. 4. Clusters c6 and c9 combined represent nearly two thirds of the entire sample and therefore these were further divided using sub-clustering. This approach was used most recently by Lo et al.

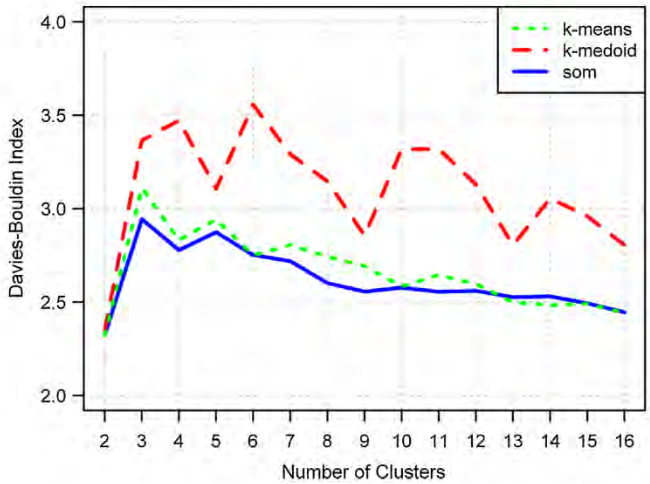

Fig. 3. Average DB index for clustering methods k-means, k-medoid, and SOM.

and Zainal et al. to break up larger clusters [57,58]. C6 and c9 were divided into four additional clusters each as shown on the right hand side of Fig. 4.

5.2. Electricity load PC characterisation

In total, ten PC's were produced using the methodology described in Section 4.2 which represent different patterns of electricity use both in terms of magnitude and timing. Fig. 5 shows the sample size for each PC as a total percentage of all classes.

Fig. 6 shows diurnal patterns of electricity use for each PC's over the six month period (note y-axes differ between subplots). In the majority of classes, a characteristic 'primary peak' and a smaller 'secondary peak' of electricity use is apparent. If a 'primary peak' occurs in the morning then the 'secondary peak' tends to be smaller in magnitude in the evening. Similarly, the converse is also true. It must be noted that PC8 shows characteristics quite different to any other class in terms of magnitude of electricity use across a 24 h period and most likely corresponds with a vacant dwelling.

Fig. 7 illustrates the intra-daily effects of electricity use for PC1 and is shown by Weekday, Saturday and Sunday. A similar effect is also observed across all classes but is unable to be shown due to space constraints. A clear distinction can be made between Weekends and Weekdays, where the majority of PC's show electricity use earlier in the morning for the latter. This earlier use of electricity during the Weekdays is most likely due to employment and schooling commitments for some or all of the occupants. Similarly, an earlier morning peak is apparent on Saturdays compared to Sundays, with the latter showing more electricity use across the afternoon period. An outlier is also evident for this particular class which corresponds to Christmas day.

The seasonal component to the classes is illustrated in Fig. 8. PC4 is presented, but like before a similar effect is observed across all classes. The brighter colours represent mid/late summer through to the darker colours indicating mid/late winter. The change in profile shape between seasons (particularly mornings and evenings) is likely to be influenced by sunrise and sunset times with the switching of lights on within the home. However, this could also be related to a change in occupancy between Summer and Winter. Similarly a change in profile shape during early morning/afternoon is apparent over the Summer which may also be related to changes in occupancy (e.g. children being at home during school holidays). However, this could also be related to an increase in external temperatures during the summer thus resulting in a greater cycling of cold appliances. A similar increase is also observed during the night (01:30–05:30) for the Summer suggesting that it is temperature rather than occupancy influencing its use during these times.

5.3. Customer PC classification

As discussed in Section 4.3 the statistical Mode was used to determine which PC customers used for the majority of time over the six month period. A multi-nominal logistic regression was then applied to determine the likelihood of households with certain characteristics using electricity in a similar manner to each PC. Table 2 presents results for the regression and shows the strength of the association for each explanatory variable with each individual PC's by way of an $Exp(B)$ value. Table 2 also shows standard errors and levels of statistical significance for each explanatory variable. Standard errors indicate variation within the explanatory variable and where large errors exist, it corresponds with small sample sizes within the sub-category. This was mitigated by combining clusters that showed similar patterns of electricity use as described in Section 4.2. However, in some instances particularly for apartments and one bedroom dwellings the total overall sample size is small (67 and 42 respectively) which contributes to large standard errors for some classes. Furthermore, this also has a

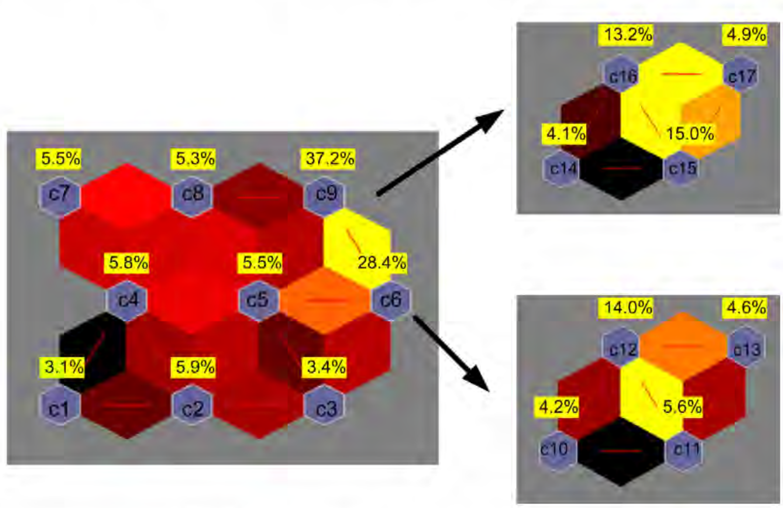

Fig. 4. Hexagonal lattice structure for SOM clusters.

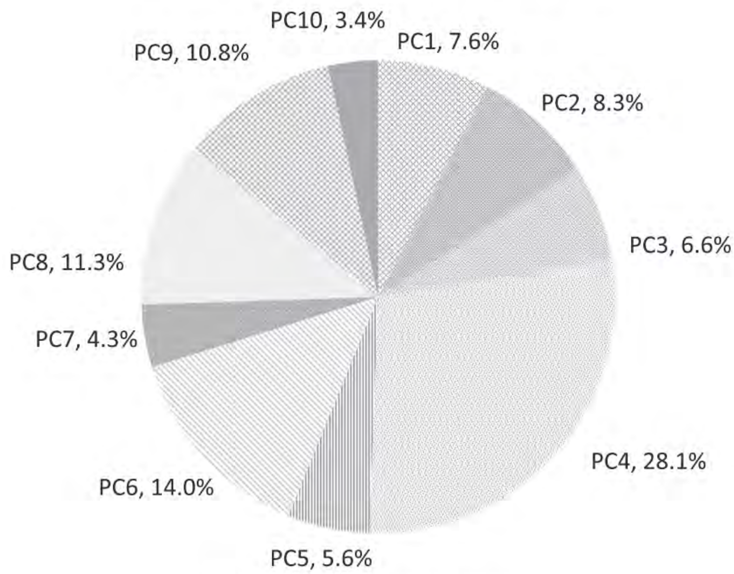

Fig. 5. Profile Class (PC) by sample sizes.

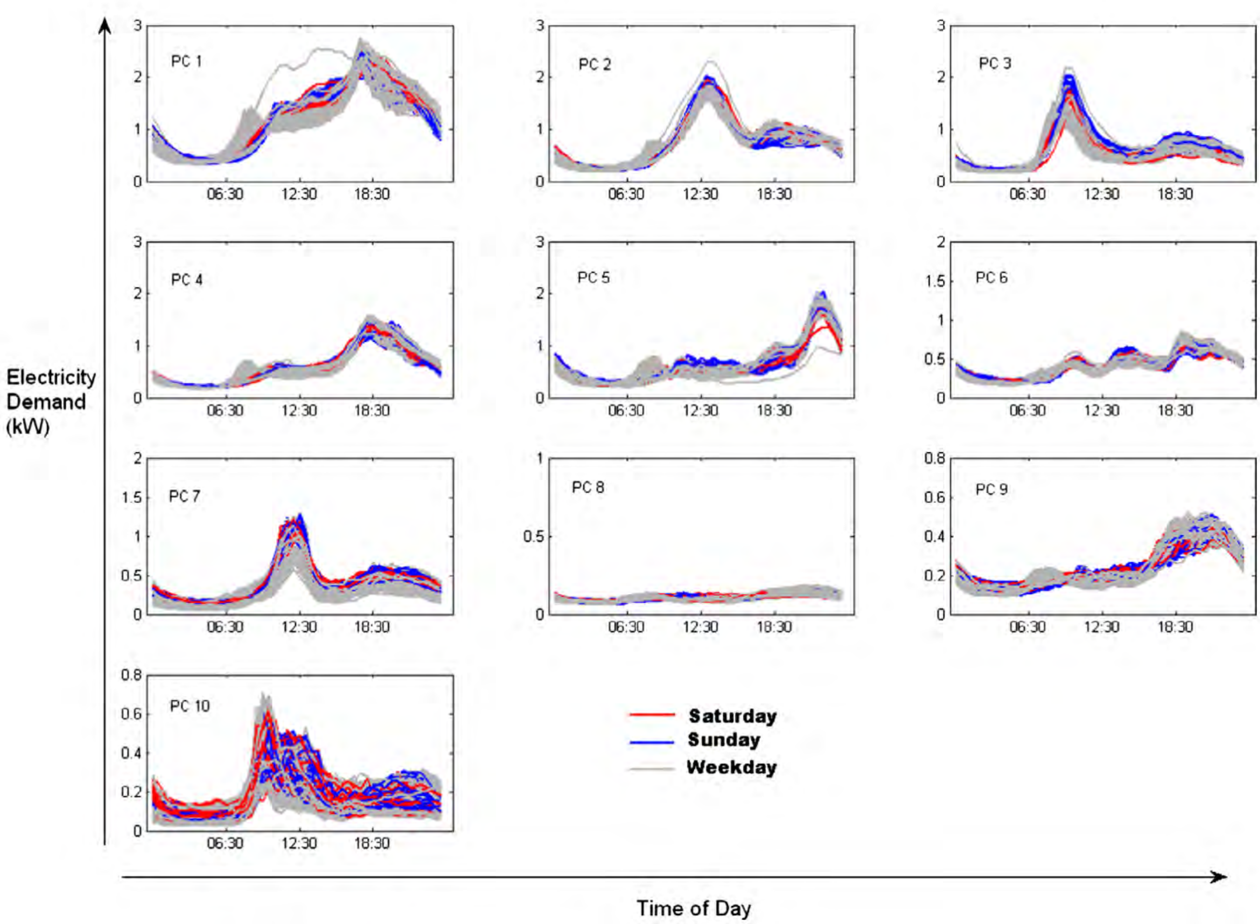

Fig. 6. PC's 1–10 over the six month period.

bearing on the statistical significance within some sub-categories in the regression model. Therefore when comparing classes, the degree with which each characteristic either positively or negatively influences use of a particular PC is additionally reported in instances where it is informative.

In the following text, each PC is discussed in terms of the influence that individual customer characteristics have on its use within the home. PC4 was used as the reference class as it corresponded with the largest number of households (28% as was shown in Fig. 5).

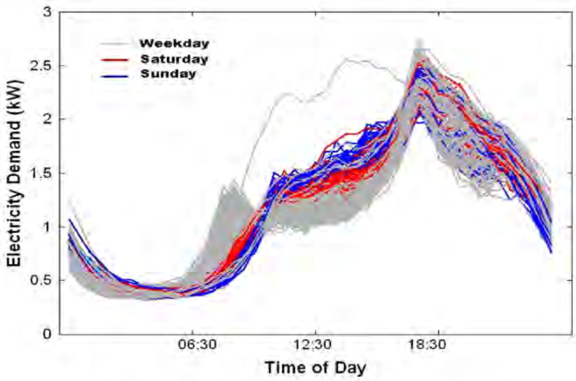

Fig. 7. PC1 by day type over the six month period.

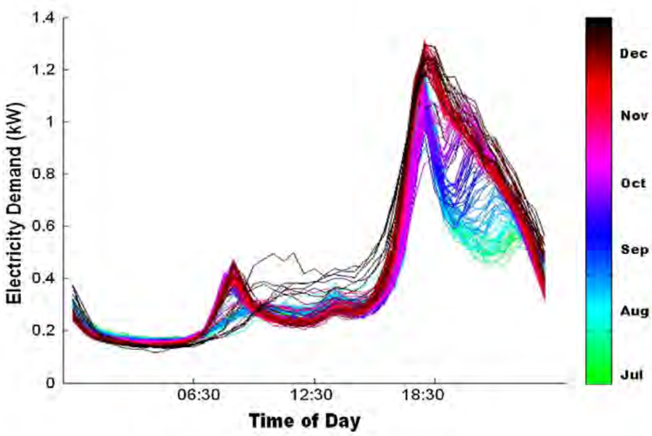

Fig. 8. PC4 for weekdays over the six month period.

5.3.1. Profile Class 1 (PC1)

This class reflects a heavy user of electricity across a 24 h period and therefore it is not surprising that occupiers of dwellings with 5+ bedrooms were more likely to use this class, with all other variables showing strong negative association within this category. Older (HoH $\geqslant$ 56 years) and middle aged (36 $\leqslant$ HoH < 55 years) were also more likely to use this PC compared to the base category, although the former was only statistically significant at the 10% level and latter not at all. A HoH social class of 'F' showed the greatest positive association for this PC but again was only shown to be significant at the 10% level. Finally, not surprisingly households that owned high energy intensive appliances such as tumble dryers and dishwashers were also more likely to use this class.

5.3.2. Profile Class 2 (PC2)

PC2 describes a high use of electricity centred around midday, with a considerably smaller evening peak compared to the previous class. The class showed poor statistically significant results within the regression model, however, it is still possible to discuss the effect. In particular, water heating showed a high association for this class which may explain the increase in electricity use around midday. Similarly, dwelling occupants which had a HoH age ($\geqslant$56 years) showed the greatest positive association. Finally, appliance types: tumble dryer, instant electric showers and water pumps all showed strong positive association.

5.3.3. Profile Class 3 (PC3)

This class showed a large morning peak with considerably less electricity used during the evening time. Similar to PC2, older HoH age ($\geqslant$56 years) showed strong positive association but this was not statistically significant. Strong positive association was also apparent for HH composition for occupants that lived alone. A strong positive association with households that use electricity for cooking was also evident but this was only statistically significant at the 10% level. Households that did not own a tumble dryer, TV > 21 inch and a desktop computer were also more likely to use this class.

5.3.4. Profile Class 4 (PC4)

As PC4 was used as the reference class all other profiles were compared against this. The class showed a similar pattern of electricity use to PC1 but with a smaller magnitude component.

5.3.5. Profile Class 5 (PC5)

PC5 shows an evening peak much later than any other class at 10:30 pm. In contrast to previous classes, younger HoH age < 36 years as well as households with a social class of 'AB' were more likely on account of negative association between all other categories for this variable, although neither were shown to be statistically significant. There was strong positive association for HH composition for people living alone although this was only shown to be significant at the 10% level. Households that did not use electricity for heating water were also more likely to use this class. Finally households that owned TV > 21 in. showed strong positive association but again was only significant at the 10% level.

5.3.6. Profile Class 6 (PC6)

This class showed three distinct electricity peaks occurring during morning, lunch and evening periods respectively, with a smaller magnitude component compared to previous classes. People living in apartments and dwellings of two and three bedrooms showed a high likelihood for using this class; however, none were shown to be statistically significant. Older households with a HoH age $\geqslant$ 56 years showed strong positive association. HH composition of live alone showed strong positive association indicating that single occupants were most likely to use this class. Households that do not use electricity to cook and/or heat water were more likely as indicated by the negative association for these categories. Finally, households that did not own a dishwasher or an instant electric shower were also more likely to use this class.

5.3.7. Profile Class 7 (PC7)

This class showed a large peak around midday but similar to PC2 showed poor statistically significant results. Comparable to PC2, this class also showed strong positive association for using electricity to heat water. Mid-sized dwellings of three and four bedrooms were more likely compared to the base category as well as households that lived with adults only. There was also strong negative association for households that did not own a dishwasher, computer or game console for this particular class.

5.3.8. Profile Class 8 (PC8)

As alluded to earlier, PC8 showed a pattern of electricity use that was quite different to the other classes in terms of the magnitude of electricity used across a 24 h period and most likely reflects an empty dwelling. Similar to PC6, people who lived in apartment dwellings showed a high likelihood of using this class, although this showed not to be statistically significant. Two bed dwelling occupants were strongly associated with this class. In contrast to PC6, younger HoH age < 36 years were more likely, with the other two age categories showing negative association. Similar to PC6, households that lived alone showed very strong positive association. Social classes 'AB' and 'F' were more likely amongst this class as well as households that did not own a tumble dryer, dishwasher or a stand-alone freezer.

Table 2
Multi-nominal logistic regression results for dwelling, occupant and appliance characteristics.

Dwelling, occupant and appliance characteristics	Profile classes																	
	PC 1		PC 2		PC 3		PC 5		PC 6		PC 7		PC 8		PC 9		PC 10	
	Exp(B)	Std. Error	Exp(B)	Std. Error	Exp(B)	Std. Error	Exp(B)	Std. Error	Exp(B)	Std. Error	Exp(B)	Std. Error	Exp(B)	Std. Error	Exp(B)	Std. Error	Exp(B)	Std. Error
Dwelling type – detached																		
Dwelling type – semi-detached	.753	.180	0.513**	.244	1.286	.237	.573	.347	.950	.130	.609	.423	.932	.152	1.088	.151	1.421	.417
Dwelling type – terraced	1.437	.256	.637	.342	1.793*	.298	.409	.641	.841	.174	1.192	.469	.783	.193	1.156	.185	1.801	.445
Dwelling type – apartment	6.920E–08	4871.374	2.530E–08	6701.038	1.477	1.112	2.663E–08	9835.488	1.512	.480	8.915E–08	7.184E+03	1.179	.439	1.106	.459	8.110E-09	0.000
No. bedrooms – 1	1.527E–08	6737.317	1.694	1.149	2.704E–09	0.000	2.572E–08	0.000	.403	.850	4.826E–08	9.858E+03	.709	.617	1.672	.615	4.268E+07	3.534E+03
No. bedrooms – 2	0.227**	.552	.759	.599	0.351*	.591	.538	1.122	1.453	.293	.502	1.280	2.122**	.330	2.448**	.355	4.810E+07	3.534E+03
No. bedrooms – 3	0.236***	.221	.932	.311	.595	.344	.763	.506	1.230	.206	1.781	.780	.968	.277	1.628	.299	3.472E+07	3.534E+03
No. bedrooms – 4	0.370***	.170	.854	.289	.621	.334	1.279	.434	.879	.203	1.669	.780	.787	.280	1.067	.303	7.514E+06	3.534E+03
No. bedrooms – 5+																		
HoH age < 36 years																		
HoH age between 36 and 55 years	1.538	.272	.588	.355	1.127	.402	.840	.437	1.002	.226	1.430E+07	3.142E+03	0.581**	.221	0.607**	.223	.580	.863
HoH age ⩾ 56 years	1.714*	.313	1.737	.382	1.338	.432	.565	.543	1.864**	.244	2.339E+07	3.142E+03	0.592**	.244	.706	.244	1.864	.884
HH composition – live alone	1.451	.382	.900	.462	5.432***	.379	3.915*	.579	2.433***	.224	.746	.885	25.838***	.253	17.687***	.251	3.202	.727
HH composition – live with adults only	.860	.171	1.051	.284	1.761*	.304	1.200	.335	1.053**	.160	1.487	.713	2.293***	.223	2.337***	.216	.620	.700
HH composition – live with adults & children																		
HoH social class – AB																		
HoH social class – C	.960	.182	.719	.299	.647	.288	.591	.346	.824	.184	.779	.823	0.591**	.205	0.691*	.205	1.485	1.081
HoH social class – DE	.980	.221	1.015	.308	0.576*	.320	.715	.419	1.215	.192	1.795	.783	0.571**	.221	0.669*	.221	2.947	1.062
HoH social class – F	2.025*	.412	2.509*	.491	1.341	.676	.724	1.074	1.593	.379	2.793	1.085	2.800**	.398	1.234	.455	13.634*	1.339
Water heating – electric	.761	.248	1.320	.438	.900	.444	0.347**	.401	0.390***	.195	3.362	1.036	.756	.274	0.493**	.241	1.623	1.051
Cooking type – electric	1.157	.173	1.501	.252	1.575*	.267	0.568*	.313	0.713**	.135	.988	.417	.788	.155	0.564***	.151	1.314	.448
Washing machine	.792	1.078	9.862E+05	0.000	1.309	1.084	8.361E+05	0.000	1.511	.590	1.101E+06	1.250E+03	.529	.468	1.078	.509	1.647	1.148
Tumble dryer	1.690**	.229	1.452	.260	0.524**	.219	.690	.343	0.802*	.126	.644	.363	0.477***	.138	0.427***	.136	.649	.349
Dishwasher	1.884**	.251	.712	.234	.868	.234	.836	.388	0.620***	.126	0.341**	.373	0.445***	.142	0.545***	.140	0.399**	.382
Shower (instant)	.823	.164	1.198	.236	.933	.231	1.017	.324	0.783**	.122	1.029	.384	.832	.142	0.749**	.138	.990	.383
Shower (pumped)	1.029	.151	.866	.220	.964	.234	1.271	.299	1.131	.126	1.012	.392	1.065	.154	1.047	.150	.689	.492
Electrical cooker	.943	.295	.793	.499	.488	.476	.733	.445	0.493**	.205	2.490	1.433	0.364***	.288	0.465**	.254	.299	1.079
Heater (plug in convective)	1.155	.154	.900	.208	1.394	.212	1.291	.303	1.009	.123	1.737	.343	.889	.143	.913	.142	1.138	.357
Freezer (stand alone)	1.093	.149	.987	.196	.856	.206	1.004	.288	1.094	.113	1.314	.346	0.596***	.135	.855	.130	0.390**	.397
Water pump	1.209	.165	1.395	.225	.754	.297	1.046	.331	1.096	.140	.790	.475	0.628**	.188	.925	.172	.950	.522
Immersion	.981	.217	.861	.303	1.335	.351	1.549	.406	0.693**	.147	1.010	.492	1.054	.180	.926	.168	0.422*	.470
TV < 21inch	1.026	.158	1.116	.211	.918	.227	1.037	.302	.899	.123	.943	.369	0.568***	.143	0.699**	.139	.645	.381
TV > 21 in.	1.043	.267	1.185	.313	0.584**	.265	3.537*	.743	.777	.157	.860	.451	0.529***	.171	.833	.177	.656	.427
Computer (desktop)	1.233	.158	.888	.199	0.624**	.216	1.367	.307	1.011	.116	0.469**	.376	0.543***	.143	0.677**	.137	.515	.417
Computer (laptop)	1.300	.161	.758	.202	.896	.221	1.338	.322	1.020	.120	0.244**	.445	0.788*	.143	.895	.141	.603	.421
Game console	1.994***	.171	.807	.258	.733	.274	1.086	.329	.878	.145	0.255*	.793	0.651**	.196	0.496***	.192	.272	.808

Base variables: Dwelling type detached; No. bedrooms – 5+; HoH age < 36 years, HH composition – live with adults and children; HoH social class – AB; Water heating – non-electric; and Cooking type – non-electric, no washing machine, no tumble dryer, no dishwas.

*** $P < 0.01$.

** $P < 0.05$.

* $P < 0.1$.

5.3.9. Profile Class 9 (PC9)

Similar to PC5 this class also shows a late evening peak but differs in terms of a much smaller magnitude component to electricity use across a 24 h period. Dwellings with a smaller number of bedrooms were more likely, particularly those with two bedrooms. A HoH age < 36 years was more likely, as indicated by negative association for the other two categories. People who lived alone were also particularly likely to use this class as indicated by strong positive association. It was also likely for people not to use electricity for heating and cooking. Households that did not own appliance types tumble dryers, dishwashers and instant electric showers were also more likely to use this PC as indicated by strong negative association.

5.3.10. Profile Class 10 (PC10)

This class shows a morning peak time use of electricity that continues until lunch time. Households, with HoH age $\geqslant$ 56 years were more likely to use this class as well as those that lived alone although neither were shown to be statistically significant. Electric water heating and cooking was also likely but was not statistically significant. Appliance types that were least likely to be owned by users of this class were: dishwasher and stand alone freezer.

The PC's described above are characterised based on dwelling, occupant and appliance characteristics and have a number of practical applications as introduced in Section 1. For example, electricity demand for new residential developments may be estimated based on knowledge of dwelling characteristics and demographics for a particular area. Similarly, by understanding how electricity is actually used within the home, new tariff structures can be tailored to suit customer lifestyles and new standard load profiles introduced for residential settlement based on ToU within the market. Finally customers that are most likely to use electricity at peak times can be targeted by utilities for demand reduction schemes.

The application of the approach described in this paper is applicable to any smart metering dataset. However, depending upon the usage profile within the electricity market the number of clusters may vary. Furthermore, the Irish smart metering trials collected detailed information on dwelling, occupant and appliance characteristics for each of the participants. It is unlikely that an electricity utility will hold this level of detailed information for each of their customers. However, information such as location (which was excluded from the Irish smart metering trial on anonymity grounds) and building type etc could be used to carry out a similar analysis. Finally, a balance was sought in this research paper between over fitting and producing a series of load profiles that were reflective of the varied manner with which electricity is used within the home.

6. Conclusions

This paper presented a clustering methodology for creating a series of representative electricity load PC's for the domestic sector in Ireland. Clustering methods: k-means, k-medoid and SOM were evaluated against a DB validity index for segmenting the data into disparate patterns of electricity use within the home. SOM proved to be the most suitable and therefore was used to segment the data prior to carrying out any aggregation. In this way characteristic information pertaining to the load profile shape is maintained.

Ten PC's for each day across a six month period were presented thus preserving the diurnal; intra-daily; and seasonality components to electricity use within the home. A multi-nominal logistic regression was then used to link PC's to dwelling, occupant and appliance characteristics. In most cases, individual customer characteristics showed either a positive or negative association with each class indicating which pattern of electricity use was more or less likely to be used within a household. As a result, it is possible to classify customers and the manner with which they use electricity based on their individual characteristics, and without prior knowledge of household electricity consumption.

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STATE OF MICHIGAN
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In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	)))))	Case No. U-20697

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[1] "A Dynamic Approach for Identifying Technological Breakthroughs with an Application in Solar Photovoltaics" (with Bixuan Sun, Sergey Kolesnikov, and Anna Goldstein). *Technological Forecasting and Social Change*. Revise and Resubmit.

[2] "Comparing and Contrasting the Institutional Relationships, Regulatory Frameworks, and Energy System Governance of European and U.S. Electric Cooperatives" (with Stephanie Lenhart, Matthew Grimley, and Elizabeth Wilson). Book chapter in *Handbook of Energy Democracy* (Routledge). Accepted.

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[5] "Energy Justice in the United States: An Emerging Research Agenda" (with Bhavin Pradhan)

[6] "Bounding the Co-Benefits of Carbon Reductions in California: Aggregate and distributional impacts" (with Andrew Fang).

[7] "Power to, from, or for the People: Distributed Energy Resources in Public Power and Rural Cooperatives" (with Stephanie Lenhart, Matthew Grimley, and Elizabeth Wilson)

[8] "The Social Construction of Electric System Benefits, Costs, and Risk: Evidence from 100 Minnesota Community Solar Contracts" (with Matthew Grimley, Isaac Evans, Poulomi Mazumder)

MANUSCRIPTS (drafts available upon request, underline indicates student or post-doc co-author)

[1] "A Cross-State Examination of the Community Shared Solar Landscape" (with Jacob Herbers, Ryan Streitz)

[2] "Navigating Interests in Community Solar: Minnesota's Municipal and Cooperative Utility Experience" (with Nicholas Neuman, Matthew Grimley, Maureen Hoffman)

[3] "Increasing Equitable Participation in Solar Energy: Opportunities and Challenges for Community Shared Solar" (with Isaac Evans, Elizabeth Arnold, Jordan Morgan)

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[5] "The Role of the CDM in Financing Wind Energy in China, 2003 – 2012" (with Joern Huenteler)

[6] "The Additionality of Clean Development Mechanism Projects in the Chinese Wind Sector" (with Joern Huenteler)

[7] "Improving Decision Making for Public R&D Investment in Energy: Utilizing Expert Elicitation in Parametric Models" (with Laura Diaz Anadon)

[8] "Crossing the Divide in Studies of Innovation: A Unifying Framework for Analysis of Multilevel Innovation Systems" (with Laura Diaz Anadon, Kira Matus, Suerie Moon, Alicia Harley, Sharmila Murthy, Vanessa Timmer, William Clark)

[9] "Socio-Technical Characteristics as Determinants of Technology Innovation for Sustainable Development: Building Bridges Across Sectors and Disciplines" (with Laura Diaz Anadon, Kira Matus, Suerie Moon, Alicia Harley, Sharmila Murthy, Vanessa Timmer, William Clark)

[10] "Innovation for Sustainable Development: A Systems Perspective for Policy Makers and Other Stakeholders" (with Laura Diaz Anadon, Kira Matus, Suerie Moon, Alicia Harley, Sharmila Murthy, Vanessa Timmer, William Clark)

[11] "The Global Innovation System: A Typology of Transnational Functions for Enhancing the Benefits of Technology for Sustainable Development" (with Laura Diaz Anadon, Kira Matus, Suerie Moon, Alicia Harley, Sharmila Murthy, Vanessa Timmer, William Clark)

TECHNICAL REPORTS AND PUBLISHED DISCUSSION PAPERS (underline indicates student or post-doc co-author)

[1] **Gabriel Chan**, Stephanie Lenhart, Lindsey Forsberg, Matthew Grimley, and Elizabeth Wilson. February 2019. *Barriers and Opportunities for Distributed Energy Resources in Minnesota's Municipal Utilities and Electric Cooperatives*. University of Minnesota Center for Science Technology and Environmental Policy. Technical Report.

"Barriers and Opportunities for Distributed Energy Resources in Minnesota's Municipal Utilities and Electric Cooperatives." University of Minnesota Center for Science Technology and Environmental Policy. Policy Brief. (February 2019)

[2] **Gabriel Chan**, Jordan Morgan, and Ryan Streitz. February 2019. *Solar for Humanity: Nonprofit Solar Partnerships with Habitat for Humanity: Landscape and Financial Analysis with Applications for Minnesota.* University of Minnesota Center for Science Technology and Environmental Policy. Technical Report.

[3] **Chan, Gabriel**, Lindsey Forsberg, Peder Garnaas-Halvorson, Samantha Holte, and DaSeul Kim. September 2018. *Issue Linkage in the Climate Regime: Gender Policies in Climate Finance*. University of Minnesota Center for Science Technology and Environmental Policy. Technical Report

"Issue Linkage in the Climate Regime: Gender Policies in Climate Finance." University of Minnesota Center for Science Technology and Environmental Policy. Policy Brief. (June 2018)

"Linking Gender Policy and Climate Finance." University of Minnesota Center for Science Technology and Environmental Policy. Policy Brief. (November 2017)

[4] **Chan, Gabriel**, Matthew Grimley, Elizabeth Arnold, Isaac Evans, Jacob Herbers, Maureen Hoffman, Benjamin Ihde, Poulomi Mazumder, Jordan Morgan, Nick Neuman, and Ryan Streitz. March 2018. *Community Shared Solar in Minnesota: Learning from the First 300 Megawatts*. University of Minnesota Center for Science Technology and Environmental Policy. Technical Report.

"Community Shared Solar in Minnesota: Learning from the First 300 Megawatts." University of Minnesota Center for Science Technology and Environmental Policy. Policy Brief. (March 2018)

[5] Bin-Nun, Amitai Y, **Gabriel Chan**, Laura Diaz Anadon, Venkatesh Narayanamurti, and Sarah Jane Maxted. November 2017. *The Department of Energy National Laboratories: Organizational Design and Management Strategies to Improve Federal Energy Innovation and Technology Transfer to the Private Sector*. Environment and Natural Resources Program and the Science, Technology, and Public Policy Program, Belfer Center for Science and International Affairs, Harvard University. Technical Report.

[6] **Gabriel Chan**, and Laura Diaz Anadon. December 2016. “Improving decision making for public R&D investment in energy: utilizing expert elicitation in parametric models.” Cambridge University, Energy Policy Research Group Working Paper Economics: 1682. Discussion Paper.

[7] Binz, Christian, **Gabriel Chan**, Claudia Doblinger, Joern Huneteler, Dongbo Shi, Tian Tang, Lei Xu, and Laura Diaz Anadon. 2015. “Energy Technology Innovation Policy in the Backdrop of the U.S.-China Emissions Agreement.” Energy Technology Innovation Policy Research Group, Belfer Center for Science and International Affairs. Workshop Report.

[8] Harley, Alicia, Sharmila Murthy, Laura Diaz Anadon, **Gabriel Chan**, Kira Matus, Suerie Moon, Vanessa Timmer, and William C. Clark. 2014. “Innovation and Access to Technologies for Sustainable Development: A Global Systems Perspective.” Harvard Sustainability Science Working Paper #2014-02. Discussion Paper.

[9] Anadon, Laura Diaz, Kira Matus, Suerie Moon, **Gabriel Chan**, Alicia Harley, Sharmila Murthy, Ahmed Abdel Latif, Kathleen Araujo, Kayje Booker, Hyundo Choi, Kristian Dubrawski, Lonia Friedlander, Christina Ingersoll, Erin Kempster, Laura Pereira, Jennie Stephens, Vanessa Timmer, Lee Vinsel, and William C. Clark. 2014. “Innovation and Access to Technologies for Sustainable Development: Diagnosing Weaknesses and Identifying Interventions in the Transnational Arena.” Harvard Sustainability Science Working Paper #2014-01. Discussion Paper.

[10] Anadon, Laura Diaz, Valentina Bosetti, **Gabriel Chan**, Gregory Nemet, and Elena Verdolini. 2014. “Energy Technology Expert Elicitations for Policy: Workshops, Modeling, and Meta-Analysis.” Belfer Center Discussion Paper #2014-08. Discussion Paper.

[11] **Gabriel Chan**, Mathias Gabel, Steffen Jenner, Stephan Schindele. 2011. “BRIC by BRIC: Governance and Energy Security in Developing Countries.” University of Tubingen Institute of Political Science Working Paper #47-2011. Discussion Paper.

[12] Anadon, Laura Diaz, Matthew Bunn, **Gabriel Chan**, Melissa Chan, Charles Jones, Ruud Kempener, Audrey Lee, Nathaniel Logar, and Venkatesh Narayanamurti. 2011. “Transforming U.S. Energy Innovation.” Energy Technology Innovation Policy Research Group, Belfer Center for Science and International Affairs. Technical Report.

[13] Anadon, Laura Diaz, Matthew Bunn, **Gabriel Chan**, Melissa Chan, Kelly Sims Gallagher, Charles Jones, Ruud Kempener, Audrey Lee, Venkatesh Narayanamurti. 2010. “DOE FY 2011 Budget Request for Energy Research, Development, Demonstration, and Deployment: Analysis and Recommendations.” Energy Technology Innovation Policy Research Group, Belfer Center for Science and International Affairs. Technical Report.

[14] **Gabriel Chan**. 2009. “Trade and the Environment: The Political Economy of CO_2 Emission Leakage with Analysis of the Steel and Oil Sands Industries.” M.I.T. Undergraduate Thesis.

REGULATORY FILINGS AND LEGISLATIVE TESTIMONY (underline indicates student or post-doc co-author)

[1] **Gabriel Chan** and <u>Matthew Grimley</u>. May 5, 2020. “Methodologies for the Avoided Distribution Cost Component of the Minnesota Value of Solar.” Minnesota Public Utilities Commission Docket M-13-867 and M-14-65. Public Comments.

[2] **Gabriel Chan**. February 25, 2020. “Testimony on the Value of Solar Tariff and Minnesota’s Community Solar Garden Program.” Oral testimony before the Minnesota House of Representatives Energy and Climate Finance and Policy Division for Bill H.F. 3368.

[3] **Gabriel Chan**. February 7, 2020. “Cooperative electricity generation and distribution.” Oral testimony before the Minnesota House of Representatives Energy and Climate Finance and Policy Division.

[4] **Gabriel Chan**, Matthew Grimley, Bixuan Sun. August 23, 2019. "Reply Comments on Xcel Energy's May 1, 2019 Filing on the Calculation of the Avoided Distribution Cost Component of the Value of Solar." Minnesota Public Utilities Commission Docket M-13-867. Public Comments and Invited Testimony before the Commission on October 31, 2019 (MN PUC staff briefing paper derived 5 decision options citing this comment and the MN PUC order on December 3, 2019 cited this comment in the establishing a stakeholder working group).

[5] **Gabriel Chan**. January 21, 2019. "Ratepayer Impact of Xcel Energy's Community Solar Garden Program." Oral testimony before the Minnesota House of Representatives Energy and Climate Finance and Policy Division for Bill H.F. 2625.

[6] **Gabriel Chan**. January 21, 2019. "Ratepayer Impact of Xcel Energy's Community Solar Garden Program." Oral testimony before the Minnesota Senate Energy and Utilities Finance and Policy Committee for Bill S.F. 1891.

[7] **Gabriel Chan**, Matthew Grimley, and Nick Stumo-Langer. December 13, 2018. "Reply Comments on Xcel Energy's 2019 VOS Calculation and Proposed 2019 Vintage Year Bill Credit Tariff Sheets." Minnesota Public Utilities Commission Docket M-13-867. Public Comments.

[8] **Gabriel Chan**, Matthew Grimley, and Nick Stumo-Langer. November 27, 2018. "Comments on Xcel Energy's 2019 VOS Calculation and Proposed 2019 Vintage Year Bill Credit Tariff Sheets." Minnesota Public Utilities Commission Docket M-13-867. Public Comments and Invited Testimony before the Commission on January 31, 2019 (MN PUC staff briefing paper derived 6 decision options citing this comment).

[9] **Gabriel Chan**, Isaac Evans, and Matthew Grimley. April 6, 2018. "Comments on Value of Solar Adders Analysis, Community Solar Gardens Program." Minnesota Public Utilities Commission Docket M-13-867. Public Comments.

[10] Narayanamurti, Venkatesh, Laura Diaz Anadon, **Gabriel Chan**, and Amitai Bin-Nun. 2015. Written Testimony to the U.S. Senate Appropriations Subcommittee on Energy & Water Development Hearing on "Securing America's Future: Realizing the Potential of the DOE National Laboratories."

OP-EDS, POLICY BRIEFS, ESSAYS, AND PODCASTS (underline indicates student or post-doc co-author)

[1] **Gabriel Chan**, Lindsey Forsberg, and Matthew Grimley. December 20, 2018. "After Xcel Energy's Zero-Carbon Pledge, Let's Make Sure the Public Benefits." *MinnPost*. Op-Ed.

[2] **Gabriel Chan**, Isaac Evans, Elizabeth Arnold, Matthew Grimley, Jacob Herbers, Benjamin Ihde, Poulomi Mazumder, Jordan Morgan, Nick Neuman, and Ryan Streitz. March 2018. "Broadening Access to Solar Energy: Community Shared Solar Programs." University of Minnesota Center for Science Technology and Environmental Policy. Policy Brief.

[3] **Gabriel Chan** and Jacob Herbers. January 30, 2018. "Solar tariffs more likely to cut than protect jobs." *Star Tribune*. Op-Ed.

[4] Ellen Anderson, **Gabriel Chan**, and Melissa Hortman. June 7, 2017. "Minnesota steps up to the plate on climate." *Star Tribune*. Op-Ed.

[5] **Gabriel Chan**. May 19, 2017. "Climate and Environmental Policy in Trump's First 100 Days: A Summary through a Gender Lens." *Gender Policy Report*. Essay.

[6] **Gabriel Chan**. January 30, 2017. "Public Funding for Energy Research and Development." *Civios*. Podcast.

[7] **Gabriel Chan** and Peder Garnaas-Halvorson. January 16, 2017. "What's to Come for More Gender-Responsive Climate Policy?" *Gender Policy Report*. Essay.

[8] **Gabriel Chan**, Jill Rook, and Ashfaqul Chowdhury. November 2016. "Cooperative Climate Change R&D That Works." University of Minnesota Center for Science Technology and Environmental Policy. Policy Brief.

[9] **Gabriel Chan**, Haley Bloomquist, Brianna Denk, and Alexandra Hillstrom. November 2016. "Guidelines for a Sectoral Sustainable Development Mechanism in the Post-2020 Climate Regime." University of Minnesota Center for Science Technology and Environmental Policy. Policy Brief.

[10] Karnamadakala Rahul Sharma and **Gabriel Chan**. October 31, 2016. "Energy Poverty: Electrification and Well-Being." *Nature: Energy - News & Views* 1 (Article 16171). Review.

DATASETS

[1] **Gabriel Chan**, Eric O'Shaughnessy, Jenny Heeter. June 2019. "Sharing the Sun: Community Solar Project List" National Renewable Energy Laboratory. https://dx.doi.org/10.7799/1560152

TEACHING

PA5790: Energy Justice Reading Group (Graduate level)
Humphrey School of Public Affairs, University of Minnesota
Fall 2019

ARCH 5250/PA 5790: Global Convergence Laboratory (Graduate level, study "abroad" course in Puerto Rico)
Humphrey School of Public Affairs and School of Architecture, University of Minnesota
Co-Instructors: Prof. Jacob Mans and Megan Vorhees
Partners: National Institute for Energy and Island Sustainability
Spring 2019, Spring 2020

PA 5045: Statistics for Public Affairs, Accelerated (Masters level)
Humphrey School of Public Affairs, University of Minnesota
Fall 2018, Fall 2019

PA 5031: Empirical Analysis I (Masters level)
Humphrey School of Public Affairs, University of Minnesota
Fall 2017

PA 5724: Climate Change Policy (Masters level)
Humphrey School of Public Affairs, University of Minnesota
Fall 2016, Fall 2017, Fall 2018

PA 5790: International Climate Change Policy: The United Nations Framework Convention on Climate Change COP22 (Masters level, study abroad course in Marrakech, Morocco)
Co-Instructors: Hon. Melissa Hortman and Ellen Anderson
Humphrey School of Public Affairs, University of Minnesota
Fall 2016

PA 5711: Science, Technology, and Environmental Policy (Masters level)
Humphrey School of Public Affairs, University of Minnesota
Fall 2015, Fall 2016, Fall 2017, Fall 2018

PA 8706: Interdisciplinary Research Seminar on Science, Technology, and Environmental Policy (Ph.D. level)
Humphrey School of Public Affairs, University of Minnesota
Fall 2015

CONSULTING AND OTHER PROFESSIONAL POSITIONS

2020 — The Ecology Center, Environmental Law & Policy Center, Great Lakes Renewable Energy Association, Solar Energy Industries Association, and Vote Solar
Retained Expert Witness/Consultant for Michigan Case U-20697 (Consumers Energy Rate Case)

2018 – 2019 — Cooperative Energy Futures
Consultant for the U.S. Department of Energy Solar in Your Community Challenge

2012 – 2015 — Belfer Center for Science and International Affairs, Harvard Kennedy School
Research Fellow, Energy Technology Innovation Policy Group

2011 – 2014 — Intergovernmental Panel on Climate Change 5th Assessment Report: Working Group III
Chapter Scientist & Contributing Author, "International Cooperation: Agreements and Instruments"
Contributing Author, "Working Group III: Technical Summary"

2007, 2009 — U.S. Department of Energy
Intern, Climate Change Technology Program

RESEARCH GRANTS, FELLOWSHIPS, AND AWARDS

2020 – 2021	U.S. Department of Energy: Solar Energy Innovation Network for "Organizational Innovation for Equitable Solar Deployment with Electric Cooperatives." **PI: Gabriel Chan**, Team Lead Organization: East River Electric Cooperative, Partners and Advisors: Clean Energy Resource Teams, Great Plains Institute, Renville-Sibley Cooperative Power Association, Lyon-Lincoln Electric Cooperative, Sioux Valley Energy, Bon Homme Yankton Electric Association, STAR Energy Services, Minnesota Farmer's Union. ($125,000)
2020 – 2021	McKnight Foundation for "Municipal and Cooperative Utility Engagement Platform." **PI: Gabriel Chan**, Partners: Clean Energy Resource Teams, Great Plains Institute. ($100,000)
2019 – 2020	Mitchell Foundation for "Trajectories of Change for Scaling Up Community Solar in Texas." PI: Varun Rai (University of Texas-Austin), **Co-PI: Gabriel Chan**. (Award Total: $100,000, University of Minnesota Sub-Award: $65,000)
2019 – 2020	McKnight Foundation for "Low-Income Access to Community Solar." **PI: Gabriel Chan**, Partners: GRID Alternatives, Fresh Energy. ($78,000)
2018 – 2021	U.S. Department of Energy Solar Energy Technology Office for "Sharing the Sun: Community Solar Data and Cost." PI: Jenny Heeter (National Renewable Energy Lab). **Sub-Award PI: Gabriel Chan**. (Award Total: $579,669, University of Minnesota Sub-Award: $125,805)
2018 – 2021	Alfred P. Sloan Foundation for "What Factor Drive Innovation in Energy Technologies? The Role of Technology Spillovers and Government Investment." PI: Venkatesh Narayanamurti, Harvard University, **Co-PI: Gabriel Chan,** Co-PI: Laura Diaz Anadon, Cambridge University. (Award Total: $560,788, University of Minnesota Sub-Award: $215,865)
2018	University of Minnesota Global Programs & Strategy Alliance, International Travel Grant. ($1,500)
2018 – 2019	Hennepin County for "Fleet Electrification Project" to University of Minnesota Institute on the Environment Link program. PI: Jeff Standish. **Advisory Faculty: Gabriel Chan**. (Award Total: $95,000, Gabriel Chan Total: $7,142)
2018	University of Minnesota Central Regional Sustainable Development Partnership for "Solar for Humanity" **PI: Gabriel Chan**, Partners: Rural Renewable Energy Alliance. ($21,000)
2017 – 2018	McKnight Foundation for "Technological and Institutional Innovation in Minnesota's Rural Electric Cooperatives and Municipal Utilities." **PI: Gabriel Chan**, Co-PI: Elizabeth Wilson, Dartmouth University. ($100,000)
2017 – 2018	University of Minnesota Center for Urban and Regional Affairs, Faculty Interactive Research Program for "Sharing the Same Sun: A Collaborative Research Initiative on Community Solar Programs: Part 1 – Lessons from Minnesota." **PI: Gabriel Chan.** ($45,427)
2017 – 2018	University of Minnesota Office of the Vice President for Research, Grant-in-Aid of Research, Artistry, and Scholarship for "Sharing the Same Sun: A Collaborative Research Initiative on Community Solar Programs: Part 2 – Cross-State Comparison." **PI: Gabriel Chan.** ($34,319)
2017	Multicultural Research Award, University of Minnesota for "Understanding Gender-Responsiveness of Multilateral Climate Finance." **PI: Gabriel Chan.** ($7,000)
2016 - 2018	National Science Foundation, Sustainability Research Network (SRN): Sustainable Healthy Cities for "Integrated Urban Infrastructure Solutions for Environmentally Sustainable, Healthy and Livable Cities." Lead PI: Anu Ramawami, Co-PIs: Patricia Culligan, Armistead Russell, Yingling Fan, Benjamin Orlove. **Research Faculty: Gabriel Chan** (among 21 research faculty). (Grant total: $12,000,000, Gabriel Chan Supervisory Responsibility: $122,937)
2014 – 2015	Dissertation Completion Fellowship, Harvard Graduate Society
2012 – 2015	Pre-Doctoral Fellowship, Belfer Center for Science, Technology, and Public Policy ($55,000)
2011 – 2012	Pre-Doctoral Fellowship, Harvard Sustainability Science Program ($17,500)
2010 – 2012	Fellow, Harvard Graduate Consortium on Energy and the Environment ($6,000)

2010 – 2011	Vicki-Norberg Bohm Fellowship, Harvard Kennedy School for "The U.S. Energy Technology Innovation System: A Cross-Sectoral Investigation of the Interface between Technologists, Policymakers and Financiers." ($7,000)
2009 – 2015	Pre-doctoral fellow, Harvard Environmental Economics Program
2009 – 2011	Doctoral Fellowship, Harvard Kennedy School
2009	U.S. Department of Energy Scholars Program

HONORS AND RECOGNITION

2019-2021	University of Minnesota McKnight Land-Grant Professorship "to advance the careers of new assistant professors at a crucial point in their professional lives." (Award: $50,000)
2019	Named to Midwest Energy News' 40 Under 40 "highlighting emerging leaders throughout the region and their work in America's transition to a clean energy economy"

ACADEMIC CONFERENCES, WORKSHOPS, AND INVITED SEMINARS (includes scheduled)

2020	Dartmouth College (New Energy seminar)
	University of Minnesota (STEP Seminar, Institute on the Environment 2nd Mondays Series, Law School: Faculty Work in Progress)
	2nd Workshop on What Factors Drive Innovation in Energy Technologies (co-convener, Cambridge)
	Cambridge Centre for Environment, Energy and Natural Resource Governance (seminar)
	2nd Workshop on Trajectories of Change for Scaling Up Community Solar in Texas (co-convener, Mitchell Foundation)
2019	University of Minnesota (STEP Seminar x2, Diversity through the Disciplines, Law School Faculty Work in Progress Seminar)
	Sustainable Healthy Cities NSF SRN Annual Workshop (presenter)
	ITIF Energy Innovation Boot Camp for Early Career Scholars (workshop participant)
	APPAM Fall Research Conference (presenter x2; discussant)
	Energy Policy Research Conference (presenter)
	Energy Justice Workshop (Indiana University; workshop participant)
	1st Workshop on What Factors Drive Innovation in Energy Technologies (co-convener, Harvard)
	RE-AMP Network Workshop on Translating Across Boundaries: A Convening of Academics and Advocates on Climate Change (workshop participant)
	American Solar Energy Society National Conference (presenter)
	International Conference on Energy Research & Social Science (presenter)
	RISE 2019: Transforming University Engagement in Pre- and Post-Disaster Environments: Lessons from Puerto Rico (presenter, workshop participant)
	1st Workshop on Trajectories of Change for Scaling Up Community Solar in Texas (co-convener, UT-Austin)
2018	Indiana University School of Public and Environmental Affairs (seminar)
	Arizona State University (workshop participant)
	Adaptation Futures Conference (Cape Town, South Africa)
	American Solar Energy Society National Solar Conference (presenter)
	Energy Policy Research Conference (presenter)
	Energy Policy Institute at the U of Chicago: Clean Energy Innovation (workshop participant)

	University of Minnesota (Freeman Seminar; STEP Seminar),
	APPAM Fall Research Conference (presenter x2; poster; discussant)
2017	Association for Public Policy Analysis & Management (presenter; discussant)
	US/International Association for Energy Economics (presenter)
	Energy Policy Research Conference (presenter)
	APPAM International Conference (presenter; discussant)
	Danish Technical University (seminar)
	EU CARISMA Project (workshop participant)
	Sustainable Healthy Cities NSF SRN Annual Workshop (presenter)
2016	Carnegie Mellon Center for Climate and Energy Decision Making (workshop participant)
	Harvard Sustainability Science Symposium (presenter)
	Association of Environmental and Resource Economists Summer Conference (presenter)
	Workshop on Making Technological Innovation Work for Sustainable Development (UCL, co-convener)
	Sustainable Healthy Cities NSF SRN Annual Workshop (workshop participant)
	Association for Public Policy Analysis & Management (presenter x2; discussant)
	Municipal Utilities Workshop (Florida State University, presenter)
2015	University of Minnesota Humphrey School (seminar x2)
	University of Minnesota Applied Economics (seminar)
	Heartland Environmental & Resource Economics Workshop at Illinois (UI-Urbana-Champaign, presenter)
	University of Colorado Boulder Environmental and Resource Economics Workshop (presenter)
	Academy of Management (presenter)
	Association for Public Policy Analysis & Management (presenter; discussant)
2014	International Energy Agency (seminar, workshop participant)
	Technology Transfer Society Conference (presenter)
	Harvard Kennedy School Energy Policy Seminar (seminar)
	INFORMS Annual Meeting (presenter)
	Harvard Business School Science Based Business Seminar (seminar)
2013	Harvard Kennedy School Energy Policy Seminar (seminar)
	Harvard Business School Science Based Business Seminar (seminar)
	Atlanta Conference on Science and Innovation Policy (presenter)
	NC State University Camp Resources (presenter)
2012	International Conference on Science and Technology Indicators (presenter)
	Snowmass Climate Change Impacts and Integrated Assessment Workshop XVIII (presenter)
2011	International Energy Workshop (presenter)
2010	Pacific Northwest National Laboratory (workshop)
	World Student Environmental Summit (keynote)
	International Conference on Greenhouse Gas Technologies (presenter)

REFEREE SERVICE

Referee for *Environmental Research Letters, Climate Policy, Nature Climate Change, Proceedings of the National Academies of Science, Environmental and Resource Economics, Energy Economics, Energy Policy, Energy Research & Social Science (x2), The Journal of Technology Transfer* (x2), Cambridge University Press (book manuscript), *Journal of Cleaner Production, Environmental Policy and Governance, Review of Environmental Economics and Policy, Journal of Benefit Cost Analysis, Sustainable Production and Consumption, International Environmental Agreements: Politics, Law and Economics, Progress in Photovoltaics, American Solar Energy Society Annual Conference Referee, Journal of Policy and Management, Renewable & Sustainable Energy Reviews,* APPAM Fall Research Conference 2020

SERVICE TO THE PUBLIC AND THE PROFESSION OUTSIDE OF THE UNIVERSITY OF MINNESOTA

Board of Directors, Minnesota Center for Environmental Advocacy (2020 -)

Advisor, Cleveland Owns report on “Equitable Community Solar: Policy and Program Guidance for Community Solar Programs that Promote Racial and Economic Equity” (2019 - 2020)

Advisor, Cooperative Energy Futures report for “Response to City of Minneapolis Request for Information for Electricity from Renewable Sources for Minneapolis Municipal Operations and Community-Wide Goals” (2019)

Study Author, Hennepin County reports on “Electric Vehicle Fleet Conversion Study” and “Hennepin County’s Diesel Vehicles: CNG as Alternative Fuel?” with Charles Noble, Jeff Standish, Chelsea Ray, and Tim Smith (2018 - 2019)

Member, Study Advisory Committee to the Energy Transition Lab, Cadmus Group, Institute for Local Self-Reliance, and the City of Minneapolis Study on “Tariffed On-Bill Financing Feasibility” (2019)

Reviewer, U.S. Department of Energy Solar in Your Community Challenge (2019)

Grant Reviewer, Research Grants Council of Hong Kong (2018)

Member, Motley Sustainability Advisory Council (2018)

Member, Advisory Committee, Midwest Energy News 40 Under 40 (2018)

Grant Reviewer, Alfred P. Sloan Foundation (2017)

SERVICE TO THE UNIVERSITY OF MINNESOTA

Faculty Advisor, Energy, Environment, and Policy Club student group (2019 -)

Faculty Advisor, Law, Policy, and Business Collaborative on Energy and Environment student group (2019 -)

Member, Humphrey School Assistant Professor in STEP Search Committee (2019 - 2020)

Chair, Institute on the Environment Associates Advisory Board (2018 -)

Member, Associate Directors Search Committee, University of Minnesota Institute on the Environment (2018 - 2019)

Member, Strategic Planning Advisory Committee, University of Minnesota Energy Transition Lab (2018 - 2019)

Member, Faculty Leadership Council, University of Minnesota Institute on the Environment (2017 -); Engagement Working Group Chair

Curator (Built & Natural Environment Area), Gender Policy Report, University of Minnesota (2017 -)

Member, Faculty Advisory Board, University of Minnesota Acara Impact Entrepreneurship Program (2016 -)

Member, Ph.D. Committee, University of Minnesota Humphrey School (2016 - 2019)

Member, Humphrey School Assistant Professor in STEP Search Committee (2017 - 2018)

Co-Chair, Humphrey School Associate Dean Search Committee (2017)

Grant Reviewer, University of Minnesota Interdisciplinary Perspectives on International Development (2016)

Grant Reviewer, UMN Office of the Vice President for Research Serendipity Grants on Renewable Energy (2015)

MEDIA APPEARANCES

Jun 16, 2020	Midwest Energy News. Quoted in "Utility lobbying and policy inattention hinder community solar, study finds."
Apr 20, 2020	Midwest Energy News. Research project profiled in "Minnesota researcher studies how rural co-ops can build solar capacity."
Feb 28, 2020	Bloomberg Businessweek. Quoted in "Google Goes Green with Others Helping to Foot the Bill."
Feb 13, 2020	Inside Climate News. Quoted in "Inside Clean Energy: The Case for Optimism."
Feb 6, 2020	MPR News: Climate Cast. Radio interview for "MN students were in Puerto Rico learning about energy resilience when a quake knocked the power out" which covers our class.
Jan 31, 2020	Humphrey School News. Quoted in "'Surreal' Experience for UMN Students Who Were in Puerto Rico During Earthquakes" which covers our class.
Jan 30, 2020	KMSP (Fox Minnesota). Television interview for "U of M students studying how to respond to natural disasters visit Puerto Rico as earthquakes hit country" which covers our class.
Jan 3, 2020	Midwest Energy News. Profiled in "Minnesota academic pursues 'engaged scholarship' on clean energy policy."
Dec 15, 2019	NPR. Quoted in "Powered by faith, religious groups emerge as a conduit for a just solar boom."
Dec 7, 2019	Knowable Magazine. Quoted in "The tricky task of tallying carbon."
Oct 10, 2019	Minnesota Daily. Quoted in "Institute on the Environment releases statewide strategic plan."
Nov 21, 2019	Midwest Energy News. Quoted in "Minnesota 'value of solar' compromise likely to boost community solar payments."
Sep 30, 2019	UMN Law School News. Quoted in "A Cross-Field Collaboration to Tackle Thorny Environmental and Energy Issues."
Sep 17, 2019	WCCO (CBS Minnesota). Television interview for "What causes gas prices to rise?"
Sep 13, 2019	Inside Climate News: Clean Economy Weekly. Referenced in "Did Solar Power's Value Just Double in Minnesota?"
Sep 9, 2019	Midwest Energy News. Quoted in "Xcel Energy seeks changes as 'value of solar' rate spike looms in Minnesota."
Feb 21, 2019	Minnesota Daily. Quoted in "UMN researchers incorporate solar panels in low-income housing" which summarizes our research.
Feb 7, 2019	Minnesota Daily. Quoted in "UMN researchers explore access to sustainable energy around Minnesota."
Jan 25, 2019	Humphrey School News. Quoted in "Humphrey School's Gabe Chan Awarded McKnight Professorship to Support Research in Energy Policy."
Jan 24, 2019	Minnesota Daily. Quoted in "UMN collaborates with Puerto Rico to explore sustainable energy." Summarized and syndicated by the Associated Press and other outlets.
Dec 27, 2018	Star Tribune. Quoted in "Complicated economics of community solar gardens subject of debate."
Dec 27, 2018	Star Tribune. Quoted in "Minnesota set to see second consecutive year of strong solar energy growth."
Dec 19, 2018	MPR News. Climate Cast. Radio interview for "How Xcel could bring carbon-free power to Minnesota."
Dec 5, 2018	Minnesota Daily. Quoted in "UMN student, professor combine efforts on environmental advocacy."
Nov 8, 2018	Minnesota Daily. Quoted in "University changes course on energy efficiency program"

Oct 12, 2018	Brainerd Dispatch. Featured in "Humphrey School students and RREAL team up for 'Solar for Humanity'"
Oct 9, 2018	WCCO (CBS Minnesota). Television interview for "What are the top ways emissions are produced?"
Apr 3, 2018	WCCO (CBS Minnesota). Television interview for "What are the fuel emission standards for our cars?"
Mar 7, 2018	MPR News. Live radio interview on "Renewables now the number two source of power generation in Minnesota"
Feb 1, 2018	MPR News: Climate Cast. Radio interview for "Solar energy is booming. Why a tariff now?"
Jan 26, 2018	MinnPost. Quoted in "Solar flare-up: new Trump tariffs inject 10,000 watts of uncertainty into one of Minnesota's fastest growing industries"
Jan 25, 2018	MPR News. Live radio interview for "Is renewable energy hurt or helped by high tariffs?"
Jan 2, 2018	Greentech Media. Research project profiled in "The National Playbook for Creating an Energy Innovation Powerhouse."
Dec 6, 2017	Minnesota Daily. Quoted in "Researchers link acceptance of climate change to group identity"
Dec 5, 2017	Humphrey School News. Quoted in "Humphrey School Students Get Up-Close Look at UN Climate Talks."
Jun 8, 2017	Minnesota Daily. Quoted in "UMN faculty to Trump: Leaving Paris Agreement will impact U.S."
Mar 28, 2017	MPR News. Quoted in "Economics, not EPA, drive down power plant emissions in Minnesota"
Feb 15, 2017	Humphrey School News. Research project profiled in "Humphrey School's Gabe Chan: More Collaboration Needed to Address Climate Change."
Dec 16, 2016	MinnPost. Quoted in "Clean Power Plan B: Why Minnesota will be a climate leader in Trump's America"
Aug 5, 2016	Inside Climate News. Quoted in "Do IPCC Reports Communicate Effectively"

PUBLIC AND PRACTITIONER PRESENTATIONS

June 4, 2020	East River Electric. Speaker to the Board of Directors monthly meeting on "Organizational Innovation for Equitable Solar Deployment with Electric Cooperatives."
May 21, 2020	National Renewable Energy Lab. Speaker at the NREL public webinar on "Sharing the Sun: Understanding Community Solar Deployment and Subscriptions."
May 5, 2020	Illinois Commerce Commission. Speaker on a webinar invited by the Environmental Law and Policy Center, Vote Solar, GridLab on "Determining the Value of Distributed Energy Resources in Illinois."
Jan 29, 2020	Minnesota Department of Commerce. Speaker at MN PUC-directed workshop on "Value of Solar's Avoided Distribution Capacity: New York's Experience"
Dec 11, 2019	Environmental Initiative. Speaker at "Electrification: Who Benefits?"
Nov 15, 2019	Solar Energy Industries Association and Smart Electric Power Alliance: Solar and Energy Storage Midwest on "How to Expand Community Solar in the Midwest"
Oct 22, 2019	Association of Professional Schools of International Affairs: Public and International Service Advisor Network (PISA) training on "Strategies for Engaging Students in International Affairs"
Oct 15, 2019	University of Minnesota Law School on "The Legal and Scientific Case for Recovering Climate Change Damages in Minnesota from Fossil Fuel Companies"
Oct 3, 2019	University of Minnesota (Social Concerns Committee) Climate Solutions: Carbon Pricing and Policy on "Innovation: Climate Savior or Climate Distraction"

Jul 9-10, 2019	Coalition for Community Solar Access: Community Solar Summit on "Opening Session & Breakfast: Achieving Community Solar at Scale" and "Market Roundup: The Early Birds - Colorado and Minnesota"
Jun 14, 2019	University of Minnesota (Institute on the Environment) Minnesota's Clean Energy Future Series on "Around the World in 70 Minutes"
May 16, 2019	U.S. Department of Energy, Solar Energy Technology Office: SETO Community Solar Workshop on "The Value of Solar Tariff: Experience from Minnesota's Solar*Rewards Community Program"
May 7, 2019	Theater of Public Policy and Community Power. Panelist on "Preparing for a Climate Crossroads"
Apr 8, 2019	Minnesota Department of Commerce: Solar Minnesota on "Barriers and Opportunities for Distributed Energy Resources in Minnesota's Municipal Utilities and Electric Cooperatives" (with Matthew Grimley)
Mar 7, 2019	University of Minnesota (co-convener), Clean Energy Resource Teams, and Great Plains Institute. "Dialogue on Distributed Energy Resources w/ Cooperative & Municipal Utilities"
Jan 29, 2019	Third Way. Briefing on "An Analytical Approach to Improving Public Energy R&D Investment Decisions" (with Laura Diaz Anadon).
Oct 5, 2018	Rural Renewable Energy Alliance. Presentation at organization headquarters on "Incorporating Solar in Habitat for Humanity Households: Study Design and Preliminary Findings."
Sep 6, 2018	Minnesota Rural Electric Association CEO's Meeting. Speaker on "The Challenges and Opportunities of Distributed Energy Resources for Municipal Utilities and Electric Cooperatives."
Apr 3, 2018	Carlson School of Management: 2018 Energy Conference on "The Role of Business in the Energy Transition."
Jun 15, 2017	Environmental Initiative. Speaker at "Policy Forum Series: The Changing Federal-State Relationship & Minnesota's Environment."
Feb 1, 2017	University of Minnesota College of Biological Science: The Petri Dish. Panelist at "Where do we go from here? The science, policy and politics of addressing and adapting to global-scale environmental change."
Jan 17, 2017	Minnesota State Bar Association. Presenter at "Environmental and Energy Law and Policy Under a Trump Administration."
Jan 10, 2017	Kinect Energy Group. Presenter on Monthly Webinar "What to Expect for Environmental Regulation in a Trump Administration."
Jan 14, 2015	U.S. Department of Energy Office of Energy Efficiency and Renewable Energy. Invited seminar on "The Commercialization of Publicly Funded Science: How Licensing Federal Laboratory Inventions Affects the Rate of Knowledge Spillovers."
Aug 22, 2014	Lawrence Berkeley National Laboratory. Invited seminar on "Evaluating Patent Licensing Agreements for Technology Diffusion at the U.S. National Labs."
Jul 29, 2010	National Renewable Energy Laboratory. Invited seminar on "Expert Elicitation of Cost, Performance, and RD&D Budgets for Greenhouse Gas Reducing Strategies: Fossil Power with CCS (with discussion of advanced vehicles)."
May 7, 2010	U.S. Department of Energy. Invited seminar on "EMF-22 and Updated 'Waterfall' Chart."

GRADUATE THESIS COMMITTEES

in progress	Dampha, Nfamara. "Socio-economic & Ecosystem Service Assessment of Climate Change Impacts in a Developing Island Capital City, Banjul The Gambia." Ph.D. in Applied Economics. *Committee Member.*
	Ernt, Lauren. TBD. M.A. in the Hubbard School of Journalism and Mass Communication.
	Domingo, Nina. TBD. Ph.D. in Bioproducts and Biosystems Engineering.

Colgan, Kimberly. TBD. Ph.D. in Bioproducts and Biosystems Engineering.

Mayer, Terin. TBD. Ph.D. in Public Affairs.

Pradhan, Bhavin. TBD. Ph.D. in Public Affairs.

2020 Dellwo, Kristy. "Bridging the Gap Between Traditional Agro-Business Sustainability Programs and the Urgency for Science-based Targets: A Case Study for CHS Inc." *Committee Chair.*

Ingulsrud, Alex. "Solar Development of Farmland in Minnesota: Mapping Scenarios Based on Ten Metrics at the Nexus of Solar and Agriculture." *Committee Member*.

O'Malley, Jane. "Comparative Analysis of CCS Development Across Five Nations." *Committee Chair.*

Kirby, Eileen. "Climate Change and Disaster Response: Informing frameworks for analyzing evacuation planning and policy effectiveness through a comparative review of wildfire and hurricane evacuation studies." *Committee Chair.*

2019 Fang, Andrew. "Carbon, Air Pollution, and Health (CAH) Co-Benefits at the urban scale: Planning documents, coupled modeling and uncertainty." Ph.D. in Public Policy. *Committee Member*.

Grimley, Matt. "'Cooperative is an Oxymoron!': The History of How 4 Electric Cooperatives Created Load Management in Minnesota." MS-STEP, Thesis. *Committee Chair.*

Forsberg, Lindsey. "Market Rules in Transition: Energy Storage and the U.S. Electricity Grid." MS-STEP, Thesis. *Committee Chair.*

Arnold, Elizabeth. "Shalefield Secrets: Use of Nondisclosure Agreements by Gas Operators in Pennsylvania." MS-STEP. *Committee Chair.*

Martin, Ben. "Effects of Ground-Mounted Solar Installations on Values of Abutting Residential Properties." MPP. *Committee Chair.*

Venning, Alex. "Behind-the-Meter Battery Energy Storage in Minnesota: Assessment of Value, Challenges, and Policy Opportunities." MS-STEP. *Committee Chair.*

Kelbrants, Ryan. "Advancing Sustainable Management Practices to Responsibly Produce Corn to Feed and Power the World." M.L.S. *Committee Member.*

2018 Sun, Bixuan. "Strategic Interactions in the Transition to Clean Energy." Ph.D. in Applied Economics. *Committee Member*.

Hillstrom, Alexandra. "Incorporating 'sustainability' in Inver Grove Heights Fleet Management." MS-STEP. *Committee Chair*.

Kosse, Rachel. "Will Doubling Urban Agriculture in the Twin Cities Improve Self-Reliance?" MS-STEP. *Committee Member*.

2017 Chowdhury, Ashfaqul. "Additionality requirement in CDM carbon offset projects: Lessons for moving forward." MPP. *Committee Chair*.

Cronk, Sarah. "The place for corporate strategy in the regulated electric industry: Case study of Xcel Energy Inc. regulatory filings." MPP. *Committee Chair*.

Gurke, Kate. "Impacts of Scale on Food Waste Technologies: An Analysis of Three Technology Options for the City of Minneapolis." MS-STEP. *Committee Chair*.

Hanson, Aaron. "Market and Policy Landscape for Energy Efficient Homes." MS-STEP. *Committee Chair*.

Plouff, Abbie. "Reimagining the Iron Range Resource Economy: Lessons from Appalachia on Economic Diversification in a Post-Mining." MPP. *Committee Chair*.

Rook, Jill. "Successful International Cooperative R&D: An Institutional Analysis to Enhance Innovation in Clean Energy Technologies." MS-STEP. *Committee Chair*.

	Santhanam, Sukumar. "Equitable Loss Allocation in Distribution Systems." MS in Electrical Engineering. *Committee Member*.
	Sharma, Rahul. "Boundary Organizations in Practice: Neighborhood-scale Organic Waste Management in Linden Hills, Minneapolis." MPP. *Committee Co-Chair*.
	Terwilliger, Hanna. "Distributed Small Scale Solar Growth in Minnesota." MPP. *Committee Chair*.
2016	Beets, Rebecca. "Governing CRISPR: Evaluating Ethics, Risk, and Regulation in Gene Drive Research." MS-STEP. *Committee Member*.
	Hemmingsen-Jaeger, Amanda. "Direct-to-consumer genetic testing: Where we are and where we could be." MS-STEP. *Committee Member*.
	Gurung, Tashi. "Climate Change Adaptation policies in Himalayan Region of Nepal. Comparative analysis of INDCs between Nepal, India, and Peru." MS-STEP. *Committee Member*.

Professional Organizations

Association of Public Policy Analysis and Management, American Solar Energy Society

Other Service

Educational Councilor for M.I.T. (2016 - 2019)

Personal Information

Date of birth: 8/3/1987, Sex: Male, Citizenship: U.S., Legal name: Gabriel Angelo Sherak Au-Chan

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	)))))	Case No. U-20697

EXHIBITS OF

KARL R. RÁBAGO

ON BEHALF OF

THE ECOLOGY CENTER
THE ENVIRONMENTAL LAW & POLICY CENTER
THE GREAT LAKES RENEWABLE ENERGY ASSOCIATION
THE SOLAR ENERGY INDUSTRIES ASSOCIATION
AND VOTE SOLAR

June 24, 2020

Karl R. Rábago

Rábago Energy LLC
2025 E. 24th Avenue, Denver, CO 80205
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Nationally recognized leader and innovator in electricity and energy law, policy, and regulation. Experienced as a regulatory expert, utility executive, research and development manager, sustainability leader, senior government official, educator, and advocate. Successful track record of working with U.S. Congress, state legislatures, governors, regulators, city councils, business leaders, researchers, academia, and community groups. Nationally recognized speaker on energy, environment, and sustainable development matters. Managed staff as large as 250; responsible for operations of research facilities with staff in excess of 600. Developed and managed budgets in excess of $300 million. Law teaching experience at Pace University Elisabeth Haub School of Law, University of Houston Law Center, and U.S. Military Academy at West Point. Military veteran.

Employment

RÁBAGO ENERGY LLC

Principal: July 2012—Present. Consulting practice dedicated to providing business sustainability, expert witness, and regulatory advice and services to organizations in the clean and advanced energy sectors. Prepared and submitted testimony in more than 30 states and 100 electricity and gas regulatory proceedings. Recognized national leader in development and implementation of award-winning "Value of Solar" alternative to traditional net metering. Additional information at www.rabagoenergy.com.

- Chairman of the Board, Center for Resource Solutions (1997-present). CRS is a not-for-profit organization based at the Presidio in California. CRS developed and manages the Green-e Renewable Electricity Brand, a nationally and internationally recognized branding program for green power and green pricing products and programs. Past chair of the Green-e Governance Board.
- Director, Solar United Neighbors (2018-present).

PACE ENERGY AND CLIMATE CENTER, PACE UNIVERSITY ELISABETH HAUB SCHOOL OF LAW

Senior Policy Advisor: September 2019—Present. Part-time advisor and staff member. Provide expert witness, project management, and business development support on electric and gas regulatory and policy issues and activities.

Executive Director: May 2014—August 2019. Leader of a team of professional and technical experts and law students in energy and climate law, policy, and regulation. Secured funding for and managed execution of research, market development support, and advisory services. Taught Energy Law. Provided learning and development opportunities for law students. Additional activities:

- Former Director, Alliance for Clean Energy – New York (2018-2019).
- Former Director, Interstate Renewable Energy Council (IREC) (2012-2018).
- Former Co-Director and Principal Investigator, Northeast Solar Energy Market Coalition (2015-2017). The NESEMC was a US Department of Energy's SunShot Initiative Solar Market Pathways project. Funded under a cooperative agreement between the US DOE and Pace University, the NESEMC worked to harmonize solar market policy and advance supportive policy and regulatory practices in the northeast United States.

Karl R. Rábago

AUSTIN ENERGY – THE CITY OF AUSTIN, TEXAS

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

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

THE AES CORPORATION

Director, Government & Regulatory Affairs: June 2006—December 2008. Director, Global Regulatory Affairs, provided regulatory support and group management to AES's international electric utility operations on five continents. Managing Director, Standards and Practices, for Greenhouse Gas Services, LLC, a GE and AES venture committed to generating and marketing greenhouse gas credits to the U.S. voluntary market. Government and regulatory affairs manager for AES Wind Generation. Managed a portfolio of regulatory and legislative initiatives to support wind energy market development in Texas, across the United States, and in many international markets.

JICARILLA APACHE NATION UTILITY AUTHORITY

Director: 1998—2008. Located in New Mexico, the JANUA was an independent utility developing profitable and autonomous utility services that provide natural gas, water utility services, low income housing, and energy planning for the Nation. Authored "First Steps" renewable energy and energy efficiency strategic plan with support from U.S. Department of Energy.

HOUSTON ADVANCED RESEARCH CENTER

Group Director, Energy and Buildings Solutions: December 2003—May 2006. Leader of energy and building science staff at a mission-driven not-for-profit contract research organization based in The Woodlands, Texas. Responsible for developing, maintaining and expanding upon technology development, application, and commercialization support programmatic activities, including the Center for Fuel Cell Research and Applications; the Gulf Coast Combined Heat and Power Application Center; and the High-Performance Green Buildings Practice. Secured funding for major new initiative in carbon nanotechnology applications in the energy sector.

- President, Texas Renewable Energy Industries Association. As elected president of the statewide business association, led and managed successful efforts to secure and implement significant expansion of the state's renewable portfolio standard as well as other policy, regulatory, and market development activities.
- Director, Southwest Biofuels Initiative. Established the Initiative as an umbrella structure for a number of biofuels related projects.

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

CARGILL DOW LLC (NOW NATUREWORKS, LLC)

Sustainability Alliances Leader: April 2002—December 2003. Integrated sustainability principles into all aspects of a ground-breaking bio-based polymer manufacturing venture. Responsible for maintaining, enhancing and building relationships with stakeholders in the worldwide sustainability community, as well as managing corporate and external sustainability initiatives.

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

ROCKY MOUNTAIN INSTITUTE

Managing Director/Principal: October 1999–April 2002. Co-authored "Small Is Profitable," a comprehensive analysis of the benefits of distributed energy resources. Provided consulting and advisory services to help business and government clients achieve sustainability through application and incorporation of Natural Capitalism principles.

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

CH2M HILL

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

PLANERGY

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

ENVIRONMENTAL DEFENSE FUND

Energy Program Manager: March 1996–January 1998. Managed renewable energy, energy efficiency, and electric utility restructuring programs. Led regulatory intervention activities in Texas and California. In Texas, played a key role in crafting Deliberative Polling processes. Participated in national environmental and energy advocacy networks, including the Energy Advocates Network, the National Wind Coordinating Committee, the NCSL Advisory Committee on Energy, and the PV-COMPACT Coordinating Council. Frequently appeared before the Texas Legislature, Austin City Council, and regulatory commissions on electric restructuring issues.

Karl R. Rábago

UNITED STATES DEPARTMENT OF ENERGY

Deputy Assistant Secretary, Utility Technologies: January 1995–March 1996. Manager of the Department's programs in renewable energy technologies and systems, electric energy systems, energy efficiency, and integrated resource planning. Supervised technology research, development and deployment activities in photovoltaics, wind energy, geothermal energy, solar thermal energy, biomass energy, high-temperature superconductivity, transmission and distribution, hydrogen, and electric and magnetic fields. Managed, coordinated, and developed international agreements. Supervised development and deployment support activities at national laboratories. Developed, advocated, and managed a Congressional budget appropriation of approximately $300 million.

STATE OF TEXAS

Commissioner, Public Utility Commission of Texas. May 1992–December 1994. Appointed by Governor Ann W. Richards. Regulated electric and telephone utilities in Texas. Co-chair and organizer of the Texas Sustainable Energy Development Council. Vice-Chair of the National Association of Regulatory Utility Commissioners (NARUC) Committee on Energy Conservation. Member and co-creator of the Photovoltaic Collaborative Market Project to Accelerate Commercial Technology (PV-COMPACT).

LAW TEACHING

Professor for a Designated Service: Pace University Elisabeth Haub School of Law, 2014-2019. Non-tenured member of faculty. Taught Energy Law. Supervised a student intern practice.

Associate Professor of Law: University of Houston Law Center, 1990–1992. Full time, tenure track member of faculty. Courses taught: Criminal Law, Environmental Law, Criminal Procedure, Environmental Crimes Seminar, Wildlife Protection Law.

Assistant Professor: United States Military Academy, West Point, New York, 1988–1990. Member of the faculty in the Department of Law. Honorably discharged in August 1990, as Major in the Regular Army. Courses taught: Constitutional Law, Military Law, and Environmental Law Seminar.

LITIGATION

Trial Defense Attorney and Prosecutor, U.S. Army Judge Advocate General's Corps, Fort Polk, Louisiana, January 1985–July 1987. Assigned to Trial Defense Service and Office of the Staff Judge Advocate.

NON-LEGAL MILITARY SERVICE

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

Karl R. Rábago

Formal Education

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

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

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

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

Karl R. Rábago

Selected Publications

"Achieving 100% Renewables: Supply-Shaping through Curtailment," with Richard Perez, Marc Perez, and Morgan Putnam, PV Tech Power, Vol. 19 (May 2019).

"A Radical Idea to Get a High-Renewable Electric Grid: Build Way More Solar and Wind than Needed," with Richard Perez, The Conversation, online at http://bit.ly/2YjnM15 (May 29, 2019).

"Reversing Energy System Inequity: Urgency and Opportunity During the Clean Energy Transition," with John Howat, John Colgan, Wendy Gerlitz, and Melanie Santiago-Mosier, National Consumer Law Center, online at www.nclc.org (Feb. 26, 2019).

"Revisiting Bonbright's Principles of Public Utility Rates in a DER World," with Radina Valova, The Electricity Journal, Vol. 31, Issue 8, pp. 9-13 (Oct. 2018).

"Achieving very high PV penetration – The need for an effective electricity remuneration framework and a central role for grid operators," Richard Perez (corresponding author), Energy Policy, Vol. 96, pp. 27-35 (2016).

"The Net Metering Riddle," Electricity Policy.com, April 2016.

"The Clean Power Plan," Power Engineering Magazine (invited editorial), Vol. 119, Issue 12 (Dec. 2, 2015)

"The 'Sharing Utility:' Enabling & Rewarding Utility Performance, Service & Value in a Distributed Energy Age," co-author, 51st State Initiative, Solar Electric Power Association (Feb. 27, 2015)

"Rethinking the Grid: Encouraging Distributed Generation," Building Energy Magazine, Vol. 33, No. 1 Northeast Sustainable Energy Association (Spring 2015)

"The Value of Solar Tariff: Net Metering 2.0," The ICER Chronicle, Ed. 1, p. 46 [International Confederation of Energy Regulators] (December 2013)

"A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation," co-author, Interstate Renewable Energy Council (October 2013)

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

"Jicarilla Apache Nation Utility Authority Strategic Plan for Energy Efficiency and Renewable Energy Development," lead author & project manager, U.S. Department of Energy First Steps Toward Developing Renewable Energy and Energy Efficiency on Tribal Lands Program (2008)

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

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

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

"Applications of Life Cycle Assessment to NatureWorks™ Polylactide (PLA) Production," co-author, Polymer Degradation and Stability 80, 403-19 (2003)

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

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

Karl R. Rábago

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

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

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

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

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

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

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

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

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

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

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

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

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

Testimony Submitted by Karl R. Rábago, on behalf of Pace Energy and Climate Center, or through Rábago Energy LLC

(as of 8 June 2020)

Date	Proceeding	Case/Docket #	On Behalf Of:
Dec. 21, 2012	VA Electric & Power Special Solar Power Tariff	Virginia SCC Case # PUE-2012-00064	Southern Environmental Law Center
May 10, 2013	Georgia Power Company 2013 IRP	Georgia PSC Docket # 36498	Georgia Solar Energy Industries Association
Jun. 23, 2013	Louisiana Public Service Commission Re-examination of Net Metering Rules	Louisiana PSC Docket # R-31417	Gulf States Solar Energy Industries Association
Aug. 29, 2013	DTE (Detroit Edison) 2013 Renewable Energy Plan Review (Michigan)	Michigan PUC Case # U-17302	Environmental Law and Policy Center
Sep. 5, 2013	CE (Consumers Energy) 2013 Renewable Energy Plan Review (Michigan)	Michigan PUC Case # U-17301	Environmental Law and Policy Center
Sep. 27, 2013	North Carolina Utilities Commission 2012 Avoided Cost Case	North Carolina Utilities Commission Docket # E-100, Sub. 136	North Carolina Sustainable Energy Association
Oct. 18, 2013	Georgia Power Company 2013 Rate Case	Georgia PSC Docket # 36989	Georgia Solar Energy Industries Association
Nov. 4, 2013	PEPCO Rate Case (District of Columbia)	District of Columbia PSC Formal Case # 1103	Grid 2.0 Working Group & Sierra Club of Washington, D.C.
Apr. 24, 2014	Dominion Virginia Electric Power 2013 IRP	Virginia SCC Case # PUE-2013-00088	Environmental Respondents
May 7, 2014	Arizona Corporation Commission Investigation on the Value and Cost of Distributed Generation	Arizona Corporation Commission Docket # E-00000J-14-0023	Rábago Energy LLC (invited presentation and workshop participation)
Jul. 10, 2014	North Carolina Utilities Commission 2014 Avoided Cost Case	North Carolina Utilities Commission Docket # E-100, Sub. 140	Southern Alliance for Clean Energy
Jul. 23, 2014	Florida Energy Efficiency and Conservation Act, Goal Setting – FPL, Duke, TECO, Gulf	Florida PSC Docket # 130199-EI, 130200-EI, 130201-EI, 130202-EI	Southern Alliance for Clean Energy
Sep. 19, 2014	Ameren Missouri's Application for Authorization to Suspend Payment of Solar Rebates	Missouri PSC File No. ET-2014-0350, Tariff # YE-2014-0494	Missouri Solar Energy Industries Association
Aug. 6, 2014	Appalachian Power Company 2014 Biennial Rate Review	Virginia SCC Case # PUE-2014-00026	Southern Environmental Law Center (Environmental Respondents)

Testimony Submitted by Karl R. Rábago, on behalf of Pace Energy and Climate Center, or through Rábago Energy LLC

(as of 8 June 2020)

Aug. 13, 2014	Wisconsin Public Service Corp. 2014 Rate Application	Wisconsin PSC Docket # 6690-UR-123	RENEW Wisconsin and Environmental Law & Policy Center
Aug. 28, 2014	WE Energies 2014 Rate Application	Wisconsin PSC Docket # 05-UR-107	RENEW Wisconsin and Environmental Law & Policy Center
Sep. 18, 2014	Madison Gas & Electric Company 2014 Rate Application	Wisconsin PSC Docket # 3720-UR-120	RENEW Wisconsin and Environmental Law & Policy Center
Sep. 29, 2014	SOLAR, LLC v. Missouri Public Service Commission	Missouri District Court Case # 14AC-CC00316	SOLAR, LLC
Jan. 28, 2016 (date of CPUC order)	Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs, etc.	California PUC Rulemaking 14-07-002	The Utility Reform Network (TURN)
Mar. 20, 2015	Orange and Rockland Utilities 2015 Rate Application	New York PSC Case # 14-E-0493	Pace Energy and Climate Center
May 22, 2015	DTE Electric Company Rate Application	Michigan PSC Case # U-17767	Michigan Environmental Council, NRDC, Sierra Club, and ELPC
Jul. 20, 2015	Hawaiian Electric Company and NextEra Application for Change of Control	Hawai'i PUC Docket # 2015-0022	Hawai'i Department of Business, Economic Development, and Tourism
Sep. 2, 2015	Wisc. PSCo Rate Application	Wisconsin PSC Case # 6690-UR-124	ELPC
Sep. 15, 2015	Dominion Virginia Electric Power 2015 IRP	Virginia SCC Case # PUE-2015-00035	Environmental Respondents
Sep. 16, 2015	NYSEG & RGE Rate Cases	New York PSC Cases 15-E-0283, -0285	Pace Energy and Climate Center
Oct. 14, 2015	Florida Power & Light Application for CCPN for Lake Okeechobee Plant	Florida PSC Case 150196-EI	Environmental Confederation of Southwest Florida
Oct. 27, 2015	Appalachian Power Company 2015 IRP	Virginia SCC Case # PUE-2015-00036	Environmental Respondents
Nov. 23, 2015	Narragansett Electric Power/National Grid Rate Design Application	Rhode Island PUC Docket No. 4568	Wind Energy Development, LLC
Dec. 8, 2015	State of West Virginia, et al., v. U.S. EPA, et al.	U.S. Court of Appeals for the District of Columbia Circuit Case No. 15-1363 and Consolidated Cases	Declaration in Support of Environmental and Public Health Intervenors in Support of Movant Respondent-Intervenors' Responses in Opposition to Motions for Stay

Testimony Submitted by Karl R. Rábago, on behalf of Pace Energy and Climate Center, or through Rábago Energy LLC

(as of 8 June 2020)

Dec. 28, 2015	Ohio Power/AEP Affiliate PPA Application	PUC of Ohio Case No. 14-1693-EL-RDR	Environmental Law and Policy Center
Jan. 19, 2016	Ohio Edison Company, Cleveland Electric Illuminating Company, and Toledo Edison Company Application for Electric Security Plan (FirstEnergy Affiliate PPA)	PUC of Ohio Case No. 14-1297-EL-SSO	Environmental Law and Policy Center
Jan. 22, 2016	Northern Indiana Public Service Company (NIPSCO) Rate Case	Indiana Utility Regulatory Commission Cause No. 44688	Citizens Action Coalition and Environmental Law and Policy Center
Mar. 18, 2016	Northern Indiana Public Service Company (NIPSCO) Rate Case – Settlement Testimony	Indiana Utility Regulatory Commission Cause No. 44688	Joint Intervenors – Citizens Action Coalition and Environmental Law and Policy Center
Mar. 18, 2016	Comments on Pilot Rate Proposals by MidAmerican and Alliant	Iowa Utility Board NOI-2014-0001	Environmental Law and Policy Center
May 27, 2016	Consolidated Edison of New York Rate Case	New York PSC Case No. 16-E-0060	Pace Energy and Climate Center
June 21, 2016	Federal Trade Commission: Workshop on Competition and Consumer Protection Issues in Solar Energy	Invited workshop presentation	Pace Energy and Climate Center
Aug. 17, 2016	Dominion Virginia Electric Power 2016 IRP	Virginia SCC Case # PUE-2016-00049	Environmental Respondents
Sep. 13, 2016	Appalachian Power Company 2016 IRP	Virginia SCC Case # PUE-2016-00050	Environmental Respondents
Oct. 27, 2016	Consumers Energy PURPA Compliance Filing	Michigan PSC Case No. U-18090	Environmental Law & Policy Center, "Joint Intervenors"
Oct. 28, 2016	Delmarva, PEPCO (PHI) Utility Transformation Filing – Review of Filing & Utilities of the Future Whitepaper	Maryland PSC Case PC 44	Public Interest Advocates
Dec. 1, 2016	DTE Electric Company PURPA Compliance Filing	Michigan PSC Case No. U-18091	Environmental Law & Policy Center, "Joint Intervenors"
Dec. 16, 2016	Rebuttal of Unitil Testimony in Net Energy Metering Docket	New Hampshire Docket No. DE 16-576	New Hampshire Sustainable Energy Association ("NHSEA")
Jan. 13, 2017	Gulf Power Company Rate Case	Florida Docket No. 160186-EI	Earthjustice, Southern Alliance for Clean Energy, League of Women Voters-Florida

Testimony Submitted by Karl R. Rábago, on behalf of Pace Energy and Climate Center, or through Rábago Energy LLC

(as of 8 June 2020)

Jan. 13, 2017	Alpena Power Company PURPA Compliance Filing	Michigan PSC Case No. U-18089	Environmental Law & Policy Center, “Joint Intervenors”
Jan. 13, 2017	Indiana Michigan Power Company PURPA Compliance Filing	Michigan PSC Case No. U-18092	Environmental Law & Policy Center, “Joint Intervenors”
Jan. 13, 2017	Northern States Power Company PURPA Compliance Filing	Michigan PSC Case No. U-18093	Environmental Law & Policy Center, “Joint Intervenors”
Jan. 13, 2017	Upper Peninsula Power Company PURPA Compliance Filing	Michigan PSC Case No. U-18094	Environmental Law & Policy Center, “Joint Intervenors”
Mar. 10, 2017	Eversource Energy Grid Modernization Plan	Massachusetts DPU Case No. 15-122/15-123	Cape Light Compact
Apr. 27, 2017	Eversource Rate Case & Grid Modernization Investments	Massachusetts DPU Case No. 17-05	Cape Light Compact
May 2, 2017	AEP Ohio Power Electric Security Plan	PUC of Ohio Case No. 16-1852-EL-SSO	Environmental Law & Policy Center
Jun. 2, 2017	Vectren Energy TDSIC Plan	Indiana URC Cause No. 44910	Citizens Action Coalition & Valley Watch
Jul. 28, 2017	Vectren Energy 2016-2017 Energy Efficiency Plan	Indiana URC Cause No. 44645	Citizens Action Coalition
Jul. 28, 2017	Vectren Energy 2018-2020 Energy Efficiency Plan	Indiana URC Cause No. 44927	Citizens Action Coalition
Aug. 1, 2017	Interstate Power & Light (Alliant) 2017 Rate Application	Iowa Utilities Board Docket No. RPU-2017-0001	Environmental Law & Policy Center, Iowa Environmental Council, Natural Resources Defense Council, and Solar Energy Industries Assoc.
Aug. 11, 2017	Dominion Virginia Electric Power 2017 IRP	Virginia SCC Case # PUR-2017-00051	Environmental Respondents
Aug. 18, 2017	Appalachian Power Company 2017 IRP	Virginia SCC Case # PUR-2017-00045	Environmental Respondents
Aug. 23, 2017	Pennsylvania Solar Future Project	PA Dept. of Environmental Protection - Alternative Ratemaking Webinar	Pace Energy and Climate Center
Aug. 25, 2017	Niagara Mohawk Power Co. d/b/a National Grid Rate Case	New York PSC Case # 17-E-0238, 17-G-0239	Pace Energy and Climate Center

Sep. 15, 2017	Niagara Mohawk Power Co. d/b/a National Grid Rate Case	New York PSC Case # 17-E-0238, 17-G-0239	Pace Energy and Climate Center
Oct. 20, 2017	Missouri PSC Working Case to Explore Emerging Issues in Utility Regulation	Missouri PSC File No. EW-2017-0245	Renew Missouri
Nov. 21, 2017	Central Hudson Gas & Electric Co. Electric and Gas Rates Cases	New York PSC Case # 17-E-0459, -0460	Pace Energy and Climate Center
Jan. 16, 2018	Great Plains Energy, Inc. Merger with Westar Energy, Inc.	Missouri PSC Case # EM-2018-0012	Renew Missouri Advocates
Jan. 19, 2018	U.S. House of Representatives, Energy and Commerce Committee	Hearing on "The PURPA Modernization Act of 2017," H.R. 4476	Rábago Energy LLC
Jan. 29, 2018	Joint Petition of Electric Distribution Companies for Approval of a Model SMART Tariff	Massachusetts D.P.U. Case No. 17-140	Boston Community Capital Solar Energy Advantage Inc. (Jointly authored with Sheryl Musgrove)
Feb. 21, 2018	Joint Petition of Electric Distribution Companies for Approval of a Model SMART Tariff	Massachusetts D.P.U. Case No. 17-140 - Surrebuttal	Boston Community Capital Solar Energy Advantage Inc. (Jointly authored with Sheryl Musgrove)
Apr. 6, 2018	Narragansett Electric Co., d/b/a National Grid Rate Case Filing	RI PUC Docket No. 4770	New Energy Rhode Island ("NERI")
Apr. 25, 2018	Narragansett Electric Co., d/b/a National Grid Power Sector Transformation Plan	Rhode Island PUC Docket No. 4780	New Energy Rhode Island ("NERI")
Apr. 26, 2018	U.S. EPA Proposed Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Stories: Electric Utility Generating Units, 82 Fed. Reg. 48,035 (Oct. 16, 2017) – "Clean Power Plan"	U.S. EPA Docket No. EPA-HQ-OAR-2016-0592	Karl R. Rábago
May 25, 2018	Orange & Rockland Utilities, Inc. Rate Case Filing	New York PSC Case Nos. 18-E-0067, 18-G-0068	Pace Energy and Climate Center
Jun. 15, 2018	Orange & Rockland Utilities, Inc. Rate Case Filing	New York PSC Case Nos. 18-E-0067, 18-G-0068 – Rebuttal Testimony	Pace Energy and Climate Center
Aug. 10, 2018	Dominion Virginia Electric Power 2018 IRP	Virginia SCC Case # PUR-2018-00065	Environmental Respondents

Testimony Submitted by Karl R. Rábago, on behalf of Pace Energy and Climate Center, or through Rábago Energy LLC

(as of 8 June 2020)

Sep. 20, 2018	Consumers Energy Company Rate Case	Michigan PSC Case No. U-20134	Environmental Law & Policy Center
Sep. 27, 2018	Potomac Electric Power Co. Notice to Construct Two 230 kV Underground Circuits	District of Columbia Public Service Commission Formal Case No. 1144	Solar United Neighbors of D.C.
Sep. 28, 2019	Arkansas Public Service Commission Investigation of Policies Related to Distributed Energy Resources	Arkansas PSC Docket No. 16-028-U	Arkansas Audubon Society & Arkansas Advanced Energy Association
Nov. 7, 2018	DTE Detroit Edison Rate Case	Michigan PSC Case No. U-20162	Natural Resources Defense Council, Michigan Environmental Council, Sierra Club
Mar. 26, 2019	Guam Power Authority Petition to Modify Net Metering	Guam PUC Docket GPA 19-04	Micronesia Renewable Energy, Inc.
Apr. 4, 2019	Community Power Network & League of Women Voters of Florida v. JEA	Circuit Court Duval County of Florida Case No. 2018-CA-002497 Div: CV-D	Earthjustice
Apr. 25, 2019	Georgia Power 2019 IRP	Georgia PSC Docket No. 42310	GSEA & GSEIA
May 10, 2019	NV Energy NV GreenEnergy 2.0 Rider	Nevada PUC Docket Nos. 18-11015, 18-11016	Vote Solar
May 24, 2019	Consolidated Edison of New York Electric and Gas Rate Cases – Misc. Issues	New York PSC Case Nos. 19-E-0065, 19-G-0066	Pace Energy and Climate Center
May 24, 2019	Consolidated Edison of New York Electric and Gas Rate Cases – Low- and Moderate-Income Panel	New York PSC Case Nos. 19-E-0065, 19-G-0066	Pace Energy and Climate Center
May 30, 2019	Connecticut DEEP Shared Clean Energy Facility Program Proposal	Connecticut Department of Energy and Environmental Protection Docket No. 19-07-01	Connecticut Fund for the Environment
Jun. 3, 2019	New Orleans City Council Rulemaking to Establish Renewable Portfolio Standards	New Orleans City Council Docket No. UD-19-01	National Audubon Society and Audubon Louisiana
Jun. 14, 2019	Consolidated Edison of New York Electric and Gas Rate Cases – Rebuttal Testimony	New York PSC Case Nos. 19-E-0065, 19-G-0066	Pace Energy and Climate Center

Jun. 24, 2019	Program to Encourage Clean Energy in Westchester County Pursuant to Public Service law Section 74-a; Staff Investigation into a Moratorium on New Natural Gas Services in the Consolidated Edison Company of New York, Inc. Service Territory	New York PSC Case Nos. 19-M-0265, 19-G-0080	Earthjustice and Pace Energy and Climate Center
Jul. 12, 2019	Application of Virginia Electric and Power Company for the Determination of the Fair Rate of Return on Common Equity	Virginia SCC Case # PUR-2019-00050	Virginia Poverty Law Center
Jul. 15, 2019	New Orleans City Council Rulemaking to Establish Renewable Portfolio Standards – Reply Comments	New Orleans City Council Docket No. UD-19-01	National Audubon Society and Audubon Louisiana
Aug. 1, 2019	Interstate Power and Light Company – General Rate Case	Iowa Utilities Board Docket No. RPU-2019-0001	Environmental Law & Policy Center and Iowa Environmental Council
Aug. 19, 2019	Consolidated Edison of New York Electric and Gas Rate Cases – Surrebuttal	New York PSC Case Nos. 19-E-0065, 19-G-0066	Pace Energy and Climate Center
Aug. 21, 2019	Connecticut Department of Energy and Environmental Protection and Public Utility Regulatory Authority Joint Proceeding on the Value of Distributed Energy Resources - Comments	Connecticut DEEP/PURA Docket No. 19-06-29	Connecticut Fund for the Environment and Save Our Sound
Sep. 10, 2019	Interstate Power and Light Company – General Rate Case - Rebuttal	Iowa Utilities Board Docket No. RPU-2019-0001	Environmental Law & Policy Center and Iowa Environmental Council
Sep. 18, 2019	Connecticut Department of Energy and Environmental Protection and Public Utility Regulatory Authority Joint Proceeding on the Value of Distributed Energy Resources – Comments and Response to Draft Study Outline	Connecticut DEEP/PURA Docket No. 19-06-29	Connecticut Fund for the Environment, Save Our Sound, E4theFuture, NE Clean Energy Council, NE Energy Efficiency Partnership, and Acadia Center
Sep. 20, 2019	Connecticut Department of Energy and Environmental Protection and Public Utility Regulatory Authority Joint Proceeding on the Value of Distributed Energy Resources – Participation in Technical Workshop 1	Connecticut DEEP/PURA Docket No. 19-06-29 http://www.ctn.state.ct.us/ctnplayer.asp?odID=16715	Connecticut Fund for the Environment and Save Our Sound

Testimony Submitted by Karl R. Rábago, on behalf of Pace Energy and Climate Center, or through Rábago Energy LLC

(as of 8 June 2020)

Oct. 4, 2019	Connecticut Department of Energy and Environmental Protection and Public Utility Regulatory Authority Joint Proceeding on the Value of Distributed Energy Resources – Participation in Technical Workshop 2	Connecticut DEEP/PURA Docket No. 19-06-29 http://www.ctn.state.ct.us/ ctnplayer.asp?odID=16766	Connecticut Fund for the Environment and Save Our Sound
Oct. 15, 2019	Electronic Consideration of the Implementation of the Net Metering Act (KY SB 100)	Kentucky Public Service Commission Case No. 2019-00256	Kentuckians for the Commonwealth & Mountain Association for Community Economic Development
Oct. 15, 2019	New Orleans City Council Rulemaking to Establish Renewable Portfolio Standards – Comments on City Council Utility Advisors' Report	New Orleans City Council Docket No. UD-19-01	National Audubon Society and Audubon Louisiana, Vote Solar, 350 New Orleans, Alliance for Clean Energy, PosiGen, and Sierra Club
Oct. 17, 2019	Indiana Michigan Power Co. General Rate Case	Michigan Public Service Company Case No. U-20359	Environmental Law & Policy Center, The Ecology Center, the Solar Energy Industries Association, and Vote Solar
Dec. 4, 2019	Alabama Power Company Petition for Certificate of Convenience and Necessity	Alabama Public Service Commission Docket No. 32953	Energy Alabama and Gasp, Inc.
Dec. 5, 2019	In the Matter of Net Metering and the Implementation of Act 827 of 2015	Arkansas Public Service Commission Docket No. 16-027-R	National Audubon Society and Arkansas Advanced Energy Association.
Dec. 6, 2019	Proposed Revisions to Vermont Public Utility Commission Rule 5.100	Vermont Public Utility Commission Case No. 19-0855-RULE	Renewable Energy Vermont ("REV")
Jan. 15, 2020	General Rate Case	Washington Utilities and Transportation Commission Docket Nos. UE-190529 & UG-190530	Puget Sound Energy

Question:

15. Provide all bill impact analyses for DG customers and non-DG customers that have been conducted on the effect of the proposed DG tariff changes.

Response:

The transition to the inflow-outflow method will occur over time as net metering customers are moved to the alternative method ten years after the installation of their equipment. Because this will be occurring over time, the Company has not calculated the bill impact to customers at this time.

Hubert W. Miller

HUBERT W. MILLER III
March 31, 2020

Rates & Regulation Department

Question:

10. Please confirm or deny. The Company delivers the outflow from a DG customer to other customers on the Company's system. If the Company denies this assertion, please explain the reason for the denial.

Response:

The excess power put back on the grid by the DG customer functions the same way as any other generation resource connected to the Company's integrated system would. This means that during periods when excess power is put on the system, either upstream or down, the wholesale market prices adjust accordingly.

Hubert W. Miller

HUBERT W. MILLER III
March 31, 2020

Rates & Regulation Department

Question:

Please refer to the Company's response to ELPC-CE-074.

122. Please confirm or deny as requested. The question asked about the disposition of outflow energy from distributed generation customers.

Response:

My understanding is that when excess power is put back on the grid by a distributed generation customer, either upstream or down, that it behaves the same as any other power the Company purchases from a generator supplying power to the grid.

Hubert W. Miller III

HUBERT W. MILLER III
May 26, 2020

Rates and Regulation Department

Question:

Please refer to the Company's response to ELPC-CE-075.

123. Please confirm or deny as requested. The question asks whether outflow energy from a distributed generation customer serves load of other customers and generates charges and revenues.

Response:

The Company proposes to compensate DG outflow based on the retail power supply rate less transmission method defined in Public Act 342 and to charge its authorized retail rates to customers who take power from the grid. The outflow would be used to serve other customers in a manner similar to that of other generating resources connected to the Company's system.

Hubert W. Miller

HUBERT W. MILLER III
May 26, 2020

Rates and Regulation Department

Question:

Please refer to the Company's response to ELPC-CE-079.

127. Please confirm that the Company's response is that it has not conducted any bill impact analysis of the effects of its proposed DG tariff changes.

Response:

The Company has not performed an individual customer bill analysis for transitioning from the net metering program to the DG program. However, its likely a customer will see an increase in their monthly bill when transitioned to the DG program as a result of using the inflow-outflow method and reducing the subsidy paid for excess energy.

Hubert W. Miller III

HUBERT W. MILLER III
May 26, 2020

Rates and Regulation Department

<u>Question:</u>

Please refer to the Company's response to ELPC-CE-110 regarding the various Brattle studies on standby customers over 550 kW, residential NEM customers, and secondary and primary NEM customers.

99. Do any of the Brattle studies credit customers for the outflow energy they send back on to the grid? If so, please indicate how this credit was incorporated into the analyses. If not, please explain why no credit was given for the outflow energy.

<u>Response:</u>

No. The studies performed by Brattle did not credit customers for the outflow energy they send back on to the grid. Instead, the Company's proposal for the Distributed Generation program includes an outflow bill credit that compensates customers for the generation not used on site and exported to the utility.

JOSNELLY C APONTE
May 26, 2020

Rates & Regulation

Question:

Please refer to the Company's response to ELPC-CE-067.

117. Please confirm that the Company's response means that the Company has not conducted an indicative cost of service analysis or any cost of service analysis for distributed generation customers.

Response:

The Company hired Brattle as a contractor to perform the cost of service analyses for distributed generation customers for the Company, which were referenced/provided in response to request U20697-ELPC-CE-110.

JOSNELLY C APONTE
May 26, 2020

Rates & Regulation

Question:

39. Load diversity
a. Please provide all quantitative studies and underlying workpapers of customer class load diversity of the Company's sub-transmission facilities.
b. Please provide all quantitative studies and underlying workpapers of customer class load diversity of the Company's primary voltage distribution facilities.
c. Please provide all quantitative studies and underlying workpapers of customer class load diversity of the Company's secondary voltage distribution facilities.
d. Provide all workpapers and source documents supporting the Company's response in electronic form, with all spreadsheet links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, provide the information in the form that most closely matches what has been requested.

Response:

I am not aware of any responsive load diversity studies for the Company's High Voltage Distribution or Low Voltage Distribution systems.

Richard T. Blumenstock

RICHARD T. BLUMENSTOCK
April 23, 2020

Electric Planning

Question:

For the following questions, please reference the direct testimony of witness Hubert W. Miller III.

94. Beginning on page 23, line 21, the testimony describes the "elements the Company evaluated when deciding which approach to use in setting the compensation credits for excess power."

a. Did the Company consider quantifying the value of resilience in developing its approach to setting the compensation credits for excess power? If the response is anything other than an unequivocal "no," explain your response in detail.

b. If not as part of this rate case, what forum does the Company consider to be most appropriate for developing a methodology to quantify the value of resilience, particularly related to DERs?

Response:

In response to parts (a) and (b), the Company considered the two compensation methods—power supply excluding transmission charges or monthly average real-time locational marginal price—described in the 2016 Energy Law when deciding how to set the credit for excess power under the DG program.

Hubert W. Miller III

HUBERT W. MILLER III
May 26, 2020

Rates and Regulation Department

Question:

49. Is the Company capable of collecting the same types of data for customers with behind the meter generation capacity less than 550 kW that the Company collected and provided to Brattle for customers with behind the meter generation capacity that exceeds 550 kW?

Response:

Please refer to the reports provided in response to U20697-ELPC-CE-110 and the data provided in response to U20697-ELPC-CE-111.

JOSNELLY C APONTE
March 30, 2020

Rates & Regulation

Question:

51. Reference Mr. Miller's testimony at page 23. What is the basis for Mr. Miller's conclusion that under the Inflow/Outflow method, a DG customer is "fairly compensated" for the power they produce and put back on the grid?

Response:

My testimony was referring to the fact that DG customers do not provide billing, customer service, or wires services as part of the excess power they put back on the grid, and so should not be compensated for these services. As such, the Company believes that compensating DG customers for their excess energy at the Company's production rate (excluding transmission) partially removes the services not supplied by the DG customers, which makes it a more fair compensation rate than crediting the full retail rate.

Hubert W. Miller

HUBERT W. MILLER III
March 30, 2020

Rates & Regulation Department

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	)))))	Case No. U-20697

EXHIBITS OF

RONNY SANDOVAL

ON BEHALF OF

THE ECOLOGY CENTER
THE ENVIRONMENTAL LAW & POLICY CENTER
THE GREAT LAKES RENEWABLE ENERGY ASSOCIATION
THE SOLAR ENERGY INDUSTRIES ASSOCIATION
AND VOTE SOLAR

June 24, 2020

Ronny Sandoval

ROS Energy Strategies | 1905 15th Street #7241 Boulder, CO 80306 | 970-460-6509 | ronny@rosstrategies.com

SUMMARY

Provide expert testimony and develop thought leadership on issues including system planning, grid modernization, and energy efficiency before public utility commissions across several states and regions. Collaborate with a variety of energy stakeholders, including national and regional organizations, to maximize opportunities for modernizing the electric system and accelerate clean energy adoption.

Invited to speak by U.S. Department of Energy; National Association of Regulatory Utility Commissioners; Regulatory Assistance Project; International Smart Grid Action Network; State and Local Energy Efficiency Action Network; Congressional Hispanic Caucus Institute; Smart Electric Power Alliance; Smart Energy Consumer Collaborative; Grid Forward; GridWise Alliance; Columbia University; Vermont Law School; The Texas Tribune; and others.

PROFESSIONAL EXPERIENCE

ROS Energy Strategies, LLC, Boulder, CO
President, 2019-Present.
Provide strategy consulting services to industry stakeholder clients on energy issues.

Interstate Renewable Energy Council, Latham, N.Y.
Board of Directors, 2019-Present.
Perform all board duties including serving on strategy and policy committees.

GridWise Alliance, Washington D.C.
Board of Directors, 2017-Present.
Perform all board duties including serving on board operations, member products, and outreach committees.

Environmental Defense Fund, New York, NY
Senior Director, Grid Modernization, 2018-2019; *Director, Grid Modernization, 2015-2018; Senior Manager, Clean Energy Idea Bank, 2013-2015;*
Managed all aspects of EDF's national grid modernization program in driving investments that increase the efficiency of the electric system and enable the integration of emerging sources of energy, including establishing priorities and positions, and managing budgets, internal staff and consultant teams. Developed effective partnerships to socialize thought leadership and experiences across regions, sectors, and formal regulatory engagements.

Consolidated Edison Company of New York, Inc., New York, NY
Senior Specialist, Energy Efficiency and Demand Management, 2010-2013.
Managed efforts to increase energy efficiency and reduce peak electricity use in capacity constrained areas of the system and forecasted the long-range impacts of energy efficiency programs for system and capital planning.
Engineer, Transmission Planning, 2008-2010; Associate Engineer, Transmission Planning, 2006-2007
Performed technical studies and developed capital system reinforcement plans needed to serve customers' growing demand for electricity.
Management Associate, 2004-2005.
Supervised operations staff and performed management functions across Con Edison's electric, gas, and steam organizations, as part of company's management training "GOLD" program.

THOUGHT LEADERSHIP

Testimony on behalf of Citizens Action Coalition and Environmental Law & Policy Center on Indianapolis Power & Light's Transmission, Distribution and Storage System Improvement Charge Petition
Indiana Utility Regulatory Commission — **October 2019**

Testimony on behalf of Local Environmental Organizations on Puerto Rico Electric Power Authority's Integrated Resource Plan
Puerto Rico Energy Bureau — **October 2019**

EDF Comments on Hawaiian Electric Companies' "Modernizing Hawai'i's Grid for Our Customers" Plan
Public Utilities Commission, State of Hawai'i — **September 2017**

EDF Testimony on Rockland Electric Company Advanced Metering Program
Board of Public Utilities, State of New Jersey — **September 2016**

EDF Testimony on First Energy Rate Cases
Pennsylvania Public Utilities Commission — **June 2016**

EDF Settlement Supporting Testimony – Duke Energy Indiana Transmission, Distribution and Storage System Improvement Charge Petition
Indiana Utility Regulatory Commission — **March 2016**

EDF Comments on Straw Proposal on the Modernization of the Electric Grid
Commonwealth of Massachusetts, Department of Public Utilities — **January 2013**

Case No: U-20697
Exhibit: CEO-31 (RS-1)
Witness: Sandoval
Date: June 24, 2020

PUBLICATIONS AND COMMUNICATIONS

A Distributed Energy Resource Roadmap for Puerto Rico: Phase I Report
Queremos Sol Coalition — **November 2019**

"The Climate Champions Podcast: Ronny Sandoval, Board Member, IREC & GWA""
Krevat Energy Innovations — **May 2019**

"New Microgrid Initiative Launches in Puerto Rico Amid Energy Policy Uncertainty""
Greentech Media — **March 2019**

"The Interaction Between Distributed Solar and Wholesale Markets"
SEIA / SEPA Solar Power New York — **December 2018**

"Grid Reliability and Resilience"
Vermont Law School Energy Symposium – Wires, Wind, and Resiliency — **October 2018**

"Voltage Management: Quick Wins for System Efficiency""
Smart Grid Northwest – GridFWD 2018 — **October 2018**

"Building Resilient Cities: Emergency Preparedness and Smart Solutions"
Congressional Hispanic Caucus Institute Leadership Conference — **September 2018**

"A Roadmap for a Clean, Modern Electric Grid"
Smart Energy Consumer Collaborative — **August 2018**

"Making the Grid Smart: Moving Toward Two-Way Communication in the Digital Age"
Department of Energy Peer Exchange — **April 2018**

"State Grid Modernization Trends"
Smart Electric Power Alliance Utility Conference — **April 2018**

"Grid Modernization: The Foundation for Climate Change Progress"
Environmental Defense Fund — **December 2017**

"Transportation, Energy and the Environment: Modernizing the Grid"
Texas Tribune Festival — **September 2017**

"Valuing Distributed Energy Resources"
Smart Electric Power Alliance Grid Evolution Summit — **July 2017**

"The US Electric Grid: Present and Future"
Columbia University Energy Symposium — **February 2017**

"The Benefits of a Smarter Grid: The 3rd Grid Modernization Index"
Department of Energy / International Smart Grid Action Network — **May 2016**

"Carbon Emissions and Energy Storage Systems"
Electricity Today Magazine — **March 2015**

"Harnessing the Hidden Efficiency: Voltage and Reactive Power Management"
National Conference and Global Forum on Science, Policy and the Environment — **January 2015**

"Grid Modernization Strategies"
The Electricity Forum Magazine — **April 2014**

"Energy Efficiency as a Transmission and Distribution Resource"
Regulatory Assistance Project — **September 2012**

EDUCATION

New York University - Stern School of Business, New York, NY
Master of Business Administration, Specializations: Finance, Law & Business, Management of Technology & Operations, 2011.

Stevens Institute of Technology, Hoboken, NY
Bachelor of Engineering, Electrical Engineering, 2004.

New York University, New York, NY
Bachelor of Science, Mathematics, 2004.

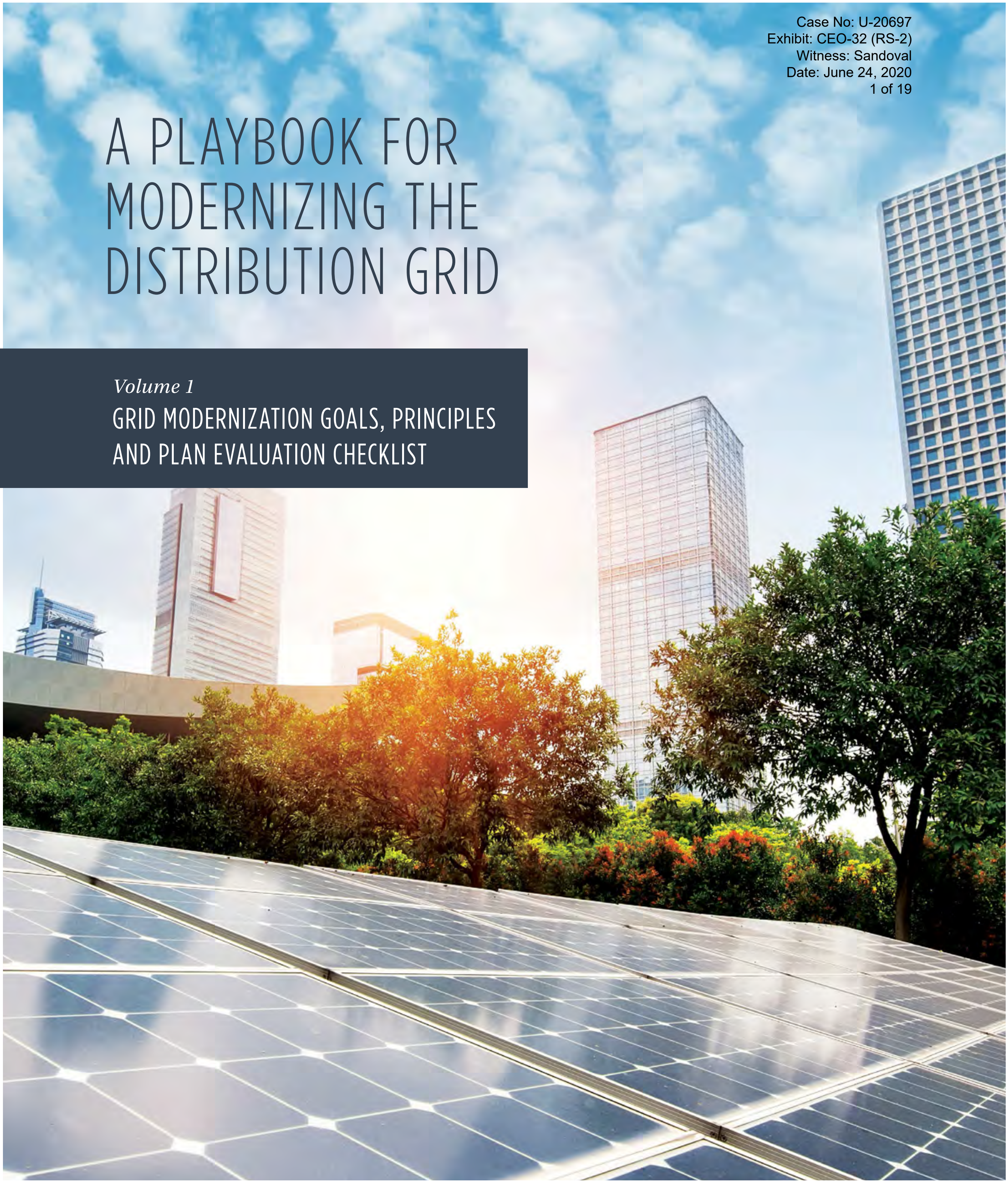
CERTIFICATIONS

Certified Energy Manager, 2012; Business Energy Professional, 2011; Six Sigma Champion, 2011.

A PLAYBOOK FOR MODERNIZING THE DISTRIBUTION GRID

Volume 1

GRID MODERNIZATION GOALS, PRINCIPLES AND PLAN EVALUATION CHECKLIST



IREC GridLAB

ABOUT THE PLAYBOOK

Developed by the Interstate Renewable Energy Council (IREC) and GridLab, A Playbook for Modernizing the Distribution Grid (hereinafter, the GridMod Playbook) is an evaluation toolkit to help regulatory stakeholders navigate, analyze and make more informed decisions about grid modernization proposals, distribution plans and grid investments. The GridMod Playbook aims to ensure more efficient and impactful grid modernization efforts in support of state public policy goals, such as clean energy adoption, across the United States and U.S. territories.

The first volume, *Grid Modernization Goals, Principles and Plan Evaluation Checklist*, consists of goals and principles for grid modernization, and an evaluation checklist – combined, they provide an initial framework to help utility regulators and regulatory stakeholders assess the merits of proposed grid modernization plans, investments and initiatives. The GridMod Playbook concept was developed at Rocky Mountain Institute (RMI)'s 2019 eLab Accelerator. This volume was developed by IREC and GridLab with peer review and input from the following individuals. No part of this document should be attributed to these individuals or their affiliated organizations.

- **Joseph Pereira,** *Colorado Office of Consumer Counsel*
- **Ed Smeloff,** *Vote Solar*
- **Chaz Teplin,** *Rocky Mountain Institute*
- **Steven Rymsha,** *Sunrun*
- **Karen Olesky,** *Public Utilities Commission of Nevada*
- **Ronny Sandoval**, *ROS Energy Strategies*

AUTHORS

Sara Baldwin, *IREC*
Ric O'Connell, *GridLab*
Curt Volkmann, *New Energy Advisors*

SUGGESTION CITATION

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CONTENTS

About IREC

IREC builds the foundation for rapid adoption of clean energy and energy efficiency to benefit people, the economy and our planet. IREC develops, informs and advances the regulatory reforms, technical standards, and workforce solutions needed to enable the streamlined, efficient and cost-effective installation of clean, distributed energy resources. www.irecusa.org

About GridLab

GridLab is an innovative non-profit that provides technical grid expertise to enhance policy decision-making and to ensure a rapid transition to a reliable, cost effective, and low carbon future. www.gridlab.org

GOALS OF GRID MODERNIZATION

Over 150 states, local governments and prominent businesses have adopted ambitious renewable and clean energy goals to rapidly reduce carbon emissions in an effort to address climate change and improve the resilience of the electric grid. Concurrently, states and utilities are undertaking “grid modernization” efforts that could enable strategic investments in new technologies for the distribution grid and allow for increased grid integration of distributed energy resources (DERs) and accompanying technologies — e.g., solar, energy storage, advanced meters, smart inverters, smart devices, demand response and electric vehicle (EV) charging infrastructure. These grid modernization efforts have the potential to leverage the deployment of DER technologies to meet policy and customer goals, while also creating more transparency and minimizing the risks associated with future grid investments.

Utilities across the country are proposing investments that add up to billions of ratepayer dollars over the next several years. Although considerable investments in the distribution grid will be needed in the coming decades to address aging infrastructure and changing demands on the electricity grid, not all grid modernization investments may be warranted or beneficial, either economically or for carbon emission reductions.

Although state policymakers, regulators and utilities may articulate discrete goals for their respective grid modernization efforts, we believe the overarching goals of grid modernization plans and ensuing investments should be to enable the swift evolution of the grid to integrate modern technologies that meet public policy and clean energy objectives, such as reducing carbon emissions and achieving 100% clean energy goals. In particular, grid modernization plans and investments should cost-effectively enable, not hinder, the electrification and decarbonization of the vehicle and building sectors, support increased energy efficiency, facilitate the deployment of DERs and improve grid reliability and resilience. The latter is especially critical given the increased frequency and intensity of natural disasters, which will only be further exacerbated by climate change. In addition, grid modernization should avoid costly and unnecessary investments in legacy grid infrastructure that may crowd out or impede the adoption of proven, cost-effective clean energy technologies and the transition to a clean energy future.

PRINCIPLES OF GRID MODERNIZATION

The following principles support and reflect the above goals of grid modernization and should be present in some form in any proposal. These principles can be used as an initial filter and framework to assess the merits of proposed grid modernization plans, investments and initiatives.

Grid Modernization should...

1. **Support and enable policy goals, including the decarbonization of the electricity system and the beneficial electrification[1] of the transportation and building sectors.** Grid modernization proposals should support relevant policy and regulatory objectives for reducing carbon emissions and enabling the electrification of the transportation and building sectors. Grid modernization investments should take into account other incentives or programs that spur increased consumer and community adoption of DERs, such as EVs and EV fast charging, electric appliances, solar, wind, energy storage, demand response and/or energy efficiency measures. Rather than duplicate utility investments, consumer investments in DERs should be leveraged and properly accounted for in grid modernization plans, particularly as optimal alternatives to more costly grid investments.
2. **Enable the adoption and optimization of distributed energy resources (DERs).** Grid modernization investments should enable, not hinder, the adoption of DERs, which can offer economic, reliability, resilience and environmental benefits to consumers, communities and utilities.[2] Grid modernization efforts should aim to increase the transparency of the grid and improve grid modeling procedures such that consumers, local governments, developers and technology providers can support the accelerated customer adoption of DERs. In addition, concurrent with grid modernization investments and plans, efforts should be made to streamline and automate interconnection processes and reduce the overall cost of DER adoption and integration for the benefit of all ratepayers.
3. **Empower people, communities and businesses to adopt affordable clean energy technologies and clean energy solutions.** Grid modernization plans and investments should help, not hinder, consumers' ability to adopt technologies and solutions that reduce the impact of their energy usage, enable easier ways to manage energy costs, and support their carbon reduction, energy consumption and/or financial goals. In addition, all interested and vested stakeholders should have easy access to information about the grid. Grid modernization investments should help support the adoption of more streamlined processes for installing, interconnecting and integrating these technologies (without impacting grid safety and reliability).
4. **Support secure and transparent information sharing and data access.** Grid modernization plans should facilitate the increased understanding of grid needs and operations among all stakeholders, including regulators. In addition, investments should enable enhanced interoperability, improved visibility and coordinated control of the grid. Improvements in transparency should allow all parties — utilities, developers, customers, local governments, regulators and other decision-makers — to access information about the grid such that DERs and other low-carbon clean energy technologies are deployed strategically, swiftly and affordably in preferred locations on the grid.

5. **Enable innovation in technology and business models.** Grid modernization plans and investments should encourage the participation of third-party stakeholders in providing information, technologies, services, and technical and financial support to consumers. To the extent applicable and appropriate, economic development and job creation goals could also be taken into account when evaluating the merits of grid modernization plans. Non-wires alternatives (NWA) should be identified and supported as viable solutions to serve identified grid needs, ahead of traditional, more capital-intensive investments (which may lead to stranded assets or more costly infrastructure). Grid modernization plans should also address whether financial incentives, penalties and/or pilot programs are needed to address the limitation of existing utility business models to encourage consumer-based technology innovation, and particularly the underlying regulatory incentive for utilities to prioritize capital expenditures to increase their profits based on the prevalent return on investment-based business model.

In addition to the above principles, we suggest that regulators and stakeholders evaluating Grid Modernization (GridMod) plans consider the following questions in their assessments (please refer to endnotes for additional explanation).

1) Does the GridMod plan include specific, measurable goals and objectives?

- **a)** Does the plan align with and support existing state policy goals and/or commission orders?
- **b)** Is it clear what specifically the utility is trying to achieve with its plan?
- **c)** Is it clear how the utility will measure the success of the plan?

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2) Does the GridMod plan include a credible Benefit/Cost Analysis (BCA) to demonstrate the plan's cost effectiveness or cost reasonableness?

- **a)** Has the utility applied an appropriate BCA methodology (e.g., least-cost/best-fit, benefit/cost ratio, Utility or Societal Cost test, etc.) for each category of GridMod expenditures?[3]
- **b)** Does the plan include disclosure of all planned GridMod expenditures including those beyond the initial period of the request?
- **c)** Do the costs reflect the full revenue requirements and customer bill impacts over the life of the assets?[4]
- **d)** Has the utility explicitly included cost contingencies and provided a corresponding range of potential BCA results?[5]
- **e)** If the BCA includes benefits from improved reliability, are the identified benefits reasonable and credible?[6]
- **f)** Does the plan include a qualitative assessment of how it will improve resilience?[7]
- **g)** Has the utility applied an appropriate discount rate in its BCA calculations?[8]
- **h)** Has the utility provided support for its key BCA assumptions and provided a sensitivity analysis of those assumptions?[9]

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3) Does the GridMod plan include detailed metrics to track progress?

- a) Are the metrics tied to the stated goals/objectives of the plan, the BCA, and the underlying BCA assumptions?
- b) Has the utility provided baselines and targets for each metric?
- c) Has the utility defined a process for ongoing tracking and reporting of metrics including costs and benefits?

4) Will the GridMod plan enable beneficial electrification?

a) Has the utility quantified and planned for the potential impact on load and demand from on-road, non-road[10] and building electrification?

b) Are the utility's assumptions about electrification consistent with state policy goals?

c) Does the plan reflect input from other relevant transportation and building sector programs/ agencies (e.g., public transportation office, large fleet vehicle users, state transportation agency, building codes and standards, etc.)?

d) Has the utility identified barriers to EV adoption in its service territory, and does the plan adequately address the barriers?

e) Does the plan include investments in the grid to accelerate EV adoption and deployment of EV charging infrastructure?

f) Does the plan include an appropriate balance between utility ownership and private ownership of EV charging infrastructure?

g) Will the utility offer rate structures to encourage off-peak EV charging and, if so, by when?

h) Does the plan include programs and incentives for the electrification of space and water heating?

5) Is the GridMod plan a requirement and/or outcome of a credible Integrated Distribution Planning (IDP) process?[11]

a) Will the plan help accelerate the adoption and integration of DERs?

b) Does the plan enable or enhance identified IDP objectives, capabilities or tools (i.e., improved load and DER forecasting, hosting capacity analyses, identification/ publication of grid needs and locational value, explicit consideration of non-utility owned DERs as non-wires alternatives (NWA) and NWA acquisition)?

c) Will the plan result in increased transparency and understanding of distribution system data (e.g., historical loads and load forecasts, hosting capacity, grid needs, beneficial locations for non-wires alternatives, etc.)?

6) Are the GridMod plan's proposed investments based on a demonstrated need?[12]

a) Has the utility defined all of the capabilities[13] the plan will enable or enhance?

b) Has the utility adequately explained how these capabilities relate to the overall goals and objectives of the plan?

c) Has the utility provided benchmarking or other credible analysis supporting the need for the new or enhanced capabilities?

7) Is the GridMod plan synergistic with other existing or planned investments (e.g., Advanced Metering Infrastructure (AMI) supporting metering as well as distribution planning/operations, etc.)?

8) Does the GridMod plan meaningfully reflect input from stakeholders, including consumer advocates, clean energy advocates, customers, large energy users, technology vendors, transportation interests and local governments?

a) Will the utility meaningfully incorporate Commission and stakeholders' input throughout the plan's design and implementation?

In addition to the above questions, the following table lists the categories of investments that may be included in a GridMod plan, along with specific examples or components in each category. The questions are intended to help evaluate the merits of the GridMod plan and may highlight the need for additional analysis and/or evidence to support proposed investments. Please refer to the Glossary for definitions of terms and acronyms, and please refer to endnotes for additional context and perspective.

Within the GridMod plan:

IF YOU SEE INVESTMENTS FOR ADVANCED METERING

EXAMPLES OR COMPONENTS INCLUDE...

- Advanced Metering Infrastructure (AMI)[14]
- Smart Meters
- Meter Data Management System (MDMS)
- AMI Head-end System
- Mesh Network
- Backhaul Network
- Field Area Network (FAN)

THEN ASK...

- Do the benefits exceed the costs (as measured by present value of revenue requirements or bill impacts)?
  - *If not, is there a credible rationale for why the AMI investment is needed?*
- How will AMI support distribution planning/operations (e.g., load forecasting, voltage monitoring, communications with intelligent grid devices, etc.)?
- Will customers be able to download and share their usage data using a standardized format, such as Green Button data? If so, by when?
- What time-varying rates will the utility offer and by when?
  - *What are the projected energy/demand savings from the proposed rates?*
  - *Are the projections credible and based on actual results from other utilities?*
- What new AMI-enabled energy efficiency and/or demand response programs will the utility offer and by when?
  - *What are the projected energy/demand savings from these programs?*
  - *Are the projections credible and based on actual results from other utilities?*
- What other tools will the utility deploy to help customers manage energy usage, and by when?
- What plans does the utility have for customer education, and are the plans sufficient?
- Are there well-defined metrics with targets to track implementation progress and benefit realization?

IF YOU SEE INVESTMENTS FOR
GRID AUTOMATION AND SENSING

EXAMPLES OR COMPONENTS INCLUDE...

- Distribution Automation (DA)
- Substation Automation
- Supervisory Control and Data Acquisition (SCADA)
- Fault Location, Isolation and Service Restoration (FLISR)
- Self-Healing Grid
- Remote Fault Indicators
- Line Sensors
- Intelligent Grid Devices
- Telemetry
- Installation of Reclosers

THEN ASK...

- Is there credible proof of cost reasonableness or cost effectiveness?
- Is the utility claiming that the automation will improve reliability? If so:
  - *Is there a demonstrated need for the reliability improvement (e.g., benchmarking results, legislative mandates, poor customer satisfaction, etc.)?*
  - *Are the projected improvements in SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index) and CAIDI (Customer Average Interruption Duration Index) credible?*[15]
  - *Is the utility using the Interruption Cost Estimate (ICE) Calculator to quantify the benefits from improved reliability? If so:*
    - » *Are the inputs to and outputs from the ICE Calculator credible?*
    - » *Has the utility accounted for the impact of momentary interruptions?*
- What steps has the utility taken to minimize the risk of technology obsolescence?[16]
- Are there well-defined metrics with targets to track implementation progress and benefit realization?

IF YOU SEE INVESTMENTS FOR
OTHER RELIABILITY IMPROVEMENTS

EXAMPLES OR COMPONENTS INCLUDE...

- Grid Hardening
- Undergrounding[17]
- Voltage Conversions
- Line Rebuilds
- Battery Energy Storage Systems (BESS)
- Microgrids
- Asset Replacements
- Installation of Reclosers

THEN ASK...

- Is there credible proof of cost reasonableness or cost effectiveness?
- Is there a demonstrated need for reliability improvement (e.g., benchmarking results, legislative mandates, poor customer satisfaction, etc.)?
- Is the utility using the ICE Calculator to quantify the benefits from improved reliability? If so:
  - *Are the inputs to and outputs from the ICE Calculator credible?*
  - *Has the utility accounted for the impact of momentary interruptions?*
- Has the utility sufficiently considered customer- and third party-owned DERs as NWA?[18]
- What steps has the utility taken to minimize the risk of technology obsolescence?[19]
- Are there well-defined metrics with targets to track implementation progress and benefit realization?

IF YOU SEE INVESTMENTS FOR

FOUNDATIONAL TOOLS AND SOFTWARE

EXAMPLES OR COMPONENTS INCLUDE...

- Load Forecasting
- DER Forecasting
- Power Flow Modeling
- Load Flow Modeling
- Fault Analysis
- Geographic Information System (GIS)
- Distribution Management System (DMS)
- Outage Management System (OMS)
- Advanced Distribution Management System (ADMS)
- Customer Information System (CIS)
- Customer Information Platform (CIP)
- Enterprise Asset Management System (EAMS)

THEN ASK...

- Has the utility sufficiently demonstrated the need for the requested tools/software (i.e., in the context of stated goals/objectives)?
- Is the utility claiming that the tools/software will improve reliability? If so, are the projected improvements measurable and credible?
- Is the utility claiming that the tools/software are needed to integrate DERs? If so, has the utility sufficiently demonstrated this need and explained how the tools/software will address this need?
- If the utility plans to use commercial-off-the-shelf (COTS) software, do the selected technologies and associated cost estimates reflect a rigorous Request for Proposals (RFP) process?[20]
- If custom software, what is the basis for the estimated costs and how do these costs compare to COTS?
- Does the utility currently have the staff and expertise to take full advantage of the software tools? If not, does the utility have an appropriate training or hiring plan?
- If COTS software is used, what steps has the utility taken to minimize the risk of technology obsolescence?[21]
- Has the utility explained how the technologies will enable or enhance IDP capabilities?
- Will the utility provide the inputs, assumptions and outputs of the tools and software in a transparent, easily understandable manner?

IF YOU SEE INVESTMENTS FOR

ADVANCED TOOLS AND SOFTWARE

EXAMPLES OR COMPONENTS INCLUDE...

- Distributed Energy Resources Management System (DERMS)
- Demand Response Management System (DRMS)
- Locational Net Benefit Analysis (LNBA)
- Locational Value Analysis
- Advanced Analytics
- Optimization Analytics

THEN ASK...

- Has the utility sufficiently demonstrated the need for the requested tools/software?
- Do existing and forecasted DER penetration levels warrant the need for the investment?[22]
- Are the requested tools/software commonly used by other utilities?
- If COTS software is used, are the selected technologies and associated cost estimates reflective of a rigorous RFP process?
- If custom software is used, what is the basis for the estimated costs and how do these compare to COTS?
- Will the requested tools/software enable communications with smart inverters?
- What steps has the utility taken to minimize the risk of technology obsolescence?[23]

IF YOU SEE INVESTMENTS FOR
TELECOMMUNICATIONS

- Broadband Fiber
- Broadband Microwave
- Wide Area Network (WAN)
- Field Area Network (FAN)

THEN ASK...

- Is there credible proof of cost reasonableness or cost effectiveness?
- Has the utility appropriately considered and incorporated public solutions (e.g., leasing lines from existing telecommunications infrastructure providers)?
- Will the proposed field area network (FAN) enable and/or support communications with advanced inverters?
- If the utility is also deploying AMI, can the AMI communications network also function as the FAN? If not, why?
- What steps has the utility taken to minimize the risk of technology obsolescence?[24]

IF YOU SEE INVESTMENTS FOR
VOLTAGE AND REACTIVE POWER MANAGEMENT

EXAMPLES OR COMPONENTS INCLUDE...

- Voltage Optimization (VO)
- Integrated Volt/VAR Control (IVVC)
- Integrated Volt/VAR Optimization (IVVO)
- Conservation Voltage Reduction (CVR)

THEN ASK...

- Has the utility appropriately considered and utilized the capabilities of advanced inverters and secondary VAR controllers?
- What are the expected peak demand and energy usage reductions, and how will the utility measure and verify the savings?
- What are the expected line loss reductions, and how will the utility measure and verify the savings?
- If the utility is also deploying AMI, how will AMI support or enhance the proposed voltage management solution?
- What steps has the utility taken to minimize the risk of technology obsolescence?[25]

IF YOU SEE INVESTMENTS FOR

DER INTEGRATION OR INTERCONNECTION

EXAMPLES OR COMPONENTS INCLUDE...

- Hosting Capacity Analysis (HCA)
- DER Interconnection Tools
- Information Sharing Portals
- Reconductoring
- Voltage Conversion
- Relay and protection upgrades or replacements
- Voltage regulator installation or replacement
- Recloser installation or replacement
- Transformer replacement
- Capacitor installation or replacement
- Upgrades to address reverse power flow

THEN ASK...

- Has the utility sufficiently demonstrated the need for the investment?
- Do existing and forecasted DER penetration levels support the need?
- Are the issues allegedly caused by DERs supported with evidence?
- Has the utility appropriately considered the capabilities of advanced inverters and secondary VAR controllers to defer or eliminate the need for the investment?
- Are state level discussions underway to adopt the The Institute of Electrical and Electronics Engineers (IEEE) *Standard 1547-2018 for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces (IEEE Std 1547-2018)* for smart inverters? If so, do the assumptions in the GridMod plan reflect the impact of this new standard?
- If the utility is proposing investments in interconnection tools, how will the utility incorporate customer and developer feedback into creation/refinement of the tools?
- If the utility is proposing an HCA:
  - *Has the utility clearly defined the HCA use cases?*
  - *What HCA methodology is the utility proposing, and is it appropriate for the use cases?*
  - *Are the utility's plans for publishing HCA results sufficient?*[26]
  - *How frequently will the utility update the HCA, and is this sufficient?*
  - *How will the utility incorporate customer and developer feedback into the creation/refinement of its HCA?*
- To what extent will the investments enable sharing of distribution system information (e.g., historical loads and load forecasts, hosting capacity, grid needs, beneficial locations for non-wires alternatives, etc.)?

IF YOU SEE INVESTMENTS FOR

PILOT PROJECTS

EXAMPLES OR COMPONENTS INCLUDE...

- Battery Energy Storage Solutions (BESS)
- Non-Wires Alternatives
- Microgrids
- Time-of-use rates
- Managed EV Charging
- Demand Response programs

THEN ASK...

- Has the utility established clear goals and objectives for each proposed pilot? Are these aligned with the overall GridMod goals and objectives?
- Has the utility demonstrated that each pilot is designed based on lessons learned and best practices from other utilities?
- Does the plan call for cross-functional collaboration and stakeholder engagement during pilot design and implementation?
- For each pilot, is there a plan for replicating or scaling to support full deployment if successful?

ENDNOTES

1 Beneficial electrification is a term for replacing direct fossil fuel use (e.g., propane, heating oil, gasoline, natural gas) with electricity in a way that reduces overall emissions and energy costs.

2 See e.g., "Whereas many States recognize that DER, if interconnected and operated in a safe and reliable manner with uniform standards across multiple jurisdictions, can offer economic, reliability, resilience, and environmental benefits to consumers, communities and utilities." *EL-1/ERE-1 Resolution Recommending State Commissions Act to Adopt and Implement Distributed Energy Resource Standard IEEE 1547-2018*, Resolution Passed by National Association of Regulatory Utility Commissioners (NARUC) Board of Directors 2020 Winter Policy Summit, 12 February 2020, page 1, available at: https://pubs.naruc.org/pub/4C436369-155D-0A36-314F-8B6C4DE0F7C7

3 See a forthcoming Berkeley Lab report, *Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations*, by Woolf, T., B. Havumaki, D. Bhandari, M. Whited (Synapse Energy Economics) and L. Schwartz, Berkeley Lab.

4 In addition to capital and O&M costs, the BCA should include full financing costs and taxes over the life of the assets, as measured by revenue requirements. It is also informative to understand how much typical customer bills are likely to increase or decrease as a result of the proposed GridMod investments.

5 Cost contingencies are amounts added to base costs in a spending plan to account for risks and uncertainty. Good project management practices call for the use of cost contingencies, particularly for large, complex projects deploying new technologies over a long time period. Risks and uncertainties that could impact GridMod plan costs include, but are not limited to, unknowns related to the integration of new and legacy IT systems; equipment deployment delays due to weather or other factors; emergence of new viable technologies; new security threats or vulnerabilities; and changing legislation or regulations. Cost contingencies effectively provide a range of expected costs and best- and worst-case benefit/cost ratios. As with all BCA assumptions and calculations, it is important that the utility's inclusion of cost contingencies be explicit and transparent.

6 Although the determination of reasonable and credible benefits is subjective, the GridMod plan should include clear, understandable, and verifiable data/analysis in support of claimed benefits. The ranges of benefits should be consistent with what the utility has demonstrated in pilots or with what other utilities have realized deploying similar technologies.

7 A 2019 report written for NARUC concluded that, although DERs and other GridMod investments can offer resilience benefits, it is unclear how to determine their value. See Rickerson, Wilson, J. Gillis, M. Bulkeley, *The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices*, Prepared by Converge Strategies for the National Association of Regulatory Utility Commissioners, April 2019, available at: https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198

8 A utility often uses its own weighted average cost of capital (WACC) as the discount rate in its BCA. However, according to the Synapse/LBNL report referenced in endnote 3, the appropriate BCA discount rate should reflect the time preference chosen by regulators on behalf of all customers (i.e., the regulatory perspective). The regulatory perspective should account for many factors, including low-cost, safe, reliable service; intergenerational equity; and other regulatory policy goals. The regulatory perspective suggests a greater emphasis on long-term impacts than what is reflected in the WACC, and that a discount rate lower than the WACC may be appropriate for the BCA. GridMod plans can use sensitivities to consider the impact of different discount rates (e.g., use the utility WACC as a high case, use a low-risk or societal discount rate as a low case)

9 A typical GridMod plan BCA includes multiple assumptions such as future reliability improvements, equipment failure rates, customer participation in DSM programs, EV adoption rates, etc. Most, if not all, of these assumptions are uncertain. A sensitivity analysis determines how much the overall costs or benefits change from a change in one or more key assumptions. A sensitivity analysis also identifies the assumptions that have the most impact on the overall costs and benefits of the GridMod plan, thus highlighting the key assumptions that the utility should further validate, monitor, and report on throughout the GridMod plan implementation.

10 Non-road electrification converts commercial and industrial equipment (such as forklifts, airport baggage handling equipment, cranes, conveyors, onshore generation for dock shipping, welding equipment, tugboats and ferries) from propane or diesel fuel to electricity.

11 A credible IDP process includes the consideration of Commission, staff and other stakeholder input when developing the IDP framework and IDP priorities.

12 A demonstrated need should include evidence that a proposed investment is actually necessary. Such evidence may include benchmarking results showing relatively poor performance, customer complaints, fines and/or penalties for poor performance, or other documented proof of poor or inadequate system conditions.

13 In this context, the authors define a capability to be the combination of skills, processes and technologies required to achieve a specific outcome or objective. The U.S. Department of Energy (DOE) has defined 26 grid modernization capabilities. See pp. 43-49 of Modern Distribution Grid Volume I: Customer and State Policy Driven Functionality, available at https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-I_v1_1.pdf.

14 The authors are generally supportive of AMI but emphasize the importance of a utility taking full advantage of AMI capabilities for the benefit of its customers. For recommendations to ensure that utilities and customers realize the full value from AMI, see e.g., Gold, Rachel, C. Waters, and D. York, *Leveraging Advanced Metering Infrastructure to Save Energy*, American Council for an Energy-Efficient Economy, Report U2001, 3 January 2020, pp. 42-43, available at: https://www.aceee.org/sites/default/files/pdfs/u2001.pdf.

15 According to the 2016 DOE report on results from the Smart Grid Investment Grant (SGIG) program, distribution automation (DA) can reduce the frequency and duration of sustained customer interruptions by 15-55%. However, p. 24 of the report cautions, "The best way to evaluate the impact of DA technologies on system reliability is to compare reliability indices before and after deployment using a well-established pre-deployment baseline. Unfortunately, many SGIG utilities had trouble establishing accurate, reliable pre-deployment baselines from which to measure performance improvements. It is recognized that the process of developing a baseline is complex and time consuming for utilities. Simply comparing reliability indices from year to year—rather than against a baseline—cannot effectively measure the full impact of DA investments." Additionally, utilities must take into account the increase in momentary interruptions for some customers when quantifying DA benefits.

16 It is important that the utility emphasize "future proofing" the GridMod technologies and capabilities to minimize the risk of obsolescence. Selected GridMod technologies should include characteristics such as over-the-air firmware and configuration upgrades without the need for field visits or equipment replacement; use of open standards, protocols, and standard service components that are not vendor-specific; enhanced memory size to support potential future use cases; architecture for ease of integration with existing and future systems; and re(use) of standard interfaces to reduce design and development costs.

17 Converting overhead facilities to underground is costly and almost never justified by reliability improvements alone. A 2012 Edison Electric Institute report, *Out of Sight, Out of Mind 2012 — an Updated Study of the Undergrounding of Overhead Power Lines* (available at https://www.eei.org/issuesandpolicy/electricreliability/undergrounding/Documents/UndergroundReport.pdf), shows an industry range of distribution overhead to underground conversion costs of $1-5 million per mile for urban construction, and $0.15-2 million per mile for rural construction. The report states, "Currently, no state has recommended wholesale undergrounding of their utility infrastructure. The cost of conversion has always been the insurmountable obstacle in each of these studies … Since 1999, an increasing number of state utility commissions have studied the possibility of mandating utilities to place all or part of their electrical facilities underground … The conclusion in every study, has determined that the cost to achieve the desired underground system is considerably too expensive for either the utility or the electrical customers."

18 For example, in the recent Green Mountain Power (GMP) Bring Your Own Device (BYOD) pilot, the utility offers bill credits to customers in exchange for control of customer-owned home battery backup systems, EV chargers, and water heaters during peak periods. Participating customers in the GMP BYOD pilot with backup batteries experience improved reliability while also providing peak demand reductions to benefit all customers. See https://www.greentechmedia.com/articles/read/green-mountain-power-kept-1100-homes-lit-up-during-storm-outage.

19 *See endnote 16.*

20 The authors strongly recommend COTS only as utilities should not be in the business of developing custom software.

21 *See endnote 16.*

22 The authors believe DERMS technologies are nascent and unnecessary even with high penetrations of DERs. For example, at the end of 2018, Pacific Gas & Electric (PG&E) had 370,000 customers with rooftop solar and a total of 4,000 MW of rooftop solar distributed generation (DG), or 20% of the private rooftop DG capacity in the U.S. PG&E also was adding 5,000 new DG customers and 55 MW of new rooftop DG to its grid each month. In its 2018 general rate case application, PG&E did not request approval of a DERMS, stating that no vendor currently provides the comprehensive set of DERMS capabilities it requires. As DERMS functionality matures, PG&E determined that it should first "invest in foundational technology including improved data quality, modeling, forecasting, communications, cybersecurity, and a DER-aware ADMS to address the near-term impacts of DERs and grid complexity while providing the groundwork for a future DERMS system."

23 *See endnote 16.*

24 *See endnote 16.*

25 *See endnote 16.*

26 HCA results should be published via online maps illustrating the hosting capacity of each circuit line section. The maps should include quick-display boxes, allowing the viewer to easily see summary information for a given node, line section or feeder. All HCA results and underlying data should also be available for download.

GLOSSARY

ADMS (Advanced Distribution Management System) - software that integrates several operational systems to optimize distribution grid performance. ADMS components can include a distribution management system (DMS); DER management system (DERMS); outage management system (OMS); demand response management system (DRMS); fault location, isolation, and service restoration (FLISR); conservation voltage reduction (CVR) and integrated Volt-VAR control (IVVC).

Advanced Inverter - a power electronics device that transforms DER direct current to alternating current. It also provides functions such as reactive power control and voltage/frequency ride-through responses to improve the stability, reliability and efficiency of the distribution system. Also known as a "smart inverter."

AMI (Advanced Metering Infrastructure) – a system that includes meters, communication networks between the meters and utility, and data collection and management systems that make the information available to the utility. AMI communications networks may also provide connectivity to other types of devices such as grid sensors, switches, and DERs.

AMI Head-end System - software that transmits and receives data, sends operational commands to smart meters, and stores interval load data from the smart meters to support customer billing.

Backhaul Network - a comunications system for transmitting large volumes of data between the AMI/field device mesh networks and the utility.

Broadband Fiber - communication systems using optical fiber that are capable of very high bandwidths.

Broadband Microwave - high frequency radio communication systems that are widely used by utilities for substation and SCADA communications.

Bring Your Own Device (BYOD) - a type of energy efficiency or demand response program involving the use of customer-owned DER devices (e.g., batteries, thermostats, etc.), and may include aggregated dispatch to provide grid services.

CAIDI (Customer Average Interruption Duration Index) – the average duration of sustained outages in a year, measured in minutes per interruption. CAIDI = SAIDI / SAIFI.

CIP (Customer Information Platform) – software for billing and revenue collection, may also include incorporation of new capabilities enabled by AMI and an MDMS.

CIS (Customer Information System) - software for billing and revenue collection.

Cost Effectiveness - determination if a proposed investment's benefits exceed the costs.

Cost Reasonableness - determination if a proposed investment represents the least-cost/ best-fit solution to address a need, regardless if the benefits exceed the costs.

COTS (Commercial-Off-The-Shelf) - software products that are ready-made and available for purchase in the commercial market.

CVR (Conservation Voltage Reduction) - intentional reduction of voltage within established limits to achieve demand reduction and energy savings for customers.

DA (Distribution Automation) - technologies including sensors, communication networks, and switches, through which a utility can improve the operational efficiency of its distribution system.

DERs (Distributed Energy Resources) - energy resources connected to the distribution system that include distributed wind and solar generation, combined heat and power, energy storage, electric vehicles, energy efficiency, demand response and microgrids.

DERMS (Distributed Energy Resources Management System) - software that provides distribution operators near real-time visibility into and control of individual DERs or DER aggregations.

DMS (Distribution Management System) - software capable of collecting, displaying and analyzing near real-time electric distribution system information. A DMS can interface with other operations applications, such as a GIS, OMS, and CIS to create an integrated view of distribution operations.

DR (Demand Response) - voluntary (and compensated) load reduction used by utilities as a system reliability or local distribution capacity resource. Demand response allows utilities to cycle certain customer loads on and off in exchange for financial incentives.

DRMS (Demand Response Management System) - software to administer and operationalize DR aggregations and other DR programs.

EAMS (Enterprise Asset Management System) - software for collecting attributes and analysis of distribution grid assets.

FAN (Field Area Network) - the communications network between distribution substations and grid devices (such as switches, sensors and AMI meters) on the distribution system.

FLISR (Fault Location, Isolation and Service Restoration) - a combination of hardware and software technologies that identify the location on a circuit where a fault has occurred, isolate the faulted line segment and restore service to all customers not connected to the faulted line segment. FLISR is also called a Self-Healing Grid.

GIS (Geographic Information System) - as defined in the context of the electric distribution system, software containing attributes of distribution grid assets and their geographic locations to enable presentation on a map. GIS may also serve as the system of record for electrical connectivity of the assets.

Green Button – an industry standard for making detailed customer energy-usage information available for download in a simple, common format.

Grid Hardening - grid improvements such as rebuilding portions of distribution circuits or proactively replacing assets to improve reliability and resilience.

Hosting Capacity - the amount of DERs that can be accommodated on the distribution system under existing grid conditions and operations without adversely impacting safety, power quality, reliability or other operational criteria, and without requiring significant infrastructure upgrades.

HCA (Hosting Capacity Analysis) - the calculation and publication of the distribution system's hosting capacity.

ICE (Interruption Cost Estimate) Calculator – an online tool for quantifying the economic impact to customers from improved reliability. See https://icecalculator.com/home.

IDP (Integrated Distribution Planning) - proactive planning for DERs growth consisting of four principal components: (1) mapping circuits' hosting capacity; (2) forecasting the expected growth of DERs on each circuit; (3) prioritizing grid upgrades to integrate DERs and (4) proactively pursuing grid upgrades (including traditional capital upgrades as well as DERs themselves) to meet anticipated grid needs.

Intelligent Grid Devices – devices such as switches and sensors that provide situational awareness, grid control capability and enable two-way communications.

IVVC (Integrated Volt/VAR Control) - a process of controlling voltage and reactive power flow on the distribution system to improve overall system performance, allowing a utility to reduce electrical losses, eliminate voltage profile problems and reduce electrical demand.

Line Loss - A natural occurrence of power delivery systems, consisting mainly of power dissipation in system components. The largest component of losses is caused by the electrical resistance of equipment and is proportional to the square of the current. As system load or current increases, system components lose more energy in the form of heat, and losses increase exponentially. Losses are therefore greatest during peak loading periods.

MAIFI (Momentary Average Interruption Frequency Index) – the average number of momentary interruptions experienced by customers in a year.

MDMS (Meter Data Management System) – a software platform that processes and stores AMI interval data used for billing.

Mesh Network - a wireless method of communication in which information is transmitted through a network of transmitters/ receivers en route to its final destination.

Microgrid - a group of interconnected loads and DERs able to operate when connected to the larger distribution grid and also able to operate as an "island" when there is an outage or other grid disturbance.

Momentary Interruptions – according to IEEE, momentary interruptions are outages lasting less than 5 minutes. Momentary interruptions are not included in the standard reliability indices of SAIDI, SAIFI, and CAIDI.

NWA (Non-Wires Alternative) – the deployment of DERs or combinations of DERs — owned by the utility, customers or other third parties — to defer or avoid the need for investment in conventional, more costly grid infrastructure. Also referred to as a Non-Wires Solution.

OMS (Outage Management System) - software to enable the efficient and safe restoration of outages, as well as communications with customers regarding restoration status. An OMS can serve as the system of record for the as-operated distribution connectivity model, as can the DMS or ADMS.

Reclosers - devices that, when sensing a fault, temporarily interrupt power downstream from their location and then automatically reclose and restore power if the fault has cleared.

Reconductoring - replacing existing conductor with larger conductor to address a thermal or voltage issue.

SAIDI (System Average Interruption Duration Index) - the average duration of sustained outages experienced per customer in a year, measured in minutes per customer. SAIDI = CAIDI x SAIFI.

SAIFI (System Average Interruption Frequency Index) - the average number of sustained outages experienced per customer in a year, measured in interruptions per customer. SAIFI = SAIDI / CAIDI.

SCADA (Supervisory Control and Data Acquisition) - a system of remote controls and telemetry to monitor and control the transmission and distribution system.

Secondary VAR Controllers - devices installed on the low-voltage side of distribution transformers to assist in controlling reactive power and voltage.

Self-Healing Grid - *see FLISR*

Smart Meter - a device capable of two-way communications used for measuring electricity consumption and other end-use information and transmitting this information on demand to a central location. Smart meters provide near real-time customer usage data, as well as interface with other 'smart' devices in the home or business.

Sustained Interruptions - according to IEEE, sustained interruptions are outages lasting more than five minutes.

Telemetry - the automatic measurement and wireless transmission of data from remote sources.

Undergrounding - conversion of existing overhead distribution facilities to underground for improved aesthetics or to address reliability issues.

Voltage Conversion - increasing the voltage of a distribution circuit (e.g., from 4kV to 12kV) to increase its capacity to serve load or to accommodate DERs.

VAR (Volt Ampere Reactive) – a measure of reactive power. Reactive power energizes the magnetic field of alternating current power system components but does no actual work, and represents the component of the current that is out of sync with the voltage.

VO (Voltage Optimization) - a combination of CVR and IVVC, resulting in optimal flow of reactive power, reduced line losses, and reduced customer demand and energy consumption.

VVO (Volt-Var Optimization) - *see VO.*

WAN (Wide Area Network) - the communications network connecting distribution substations with operations/control centers and other utility facilities.

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Expanding PV Value: Lessons Learned from Utility-led Distributed Energy Resource Aggregation in the United States

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List of Acronyms

AHJ	authority having jurisdiction
CHP	combined heat and power
Con Ed	Consolidated Edison
DER	distributed energy resource
DERMS	distributed energy resource management system(s)
DG	distributed generation
EV	electric vehicle
GCN	Green Charge Network
GE	General Electric
HECO	Hawaiian Electric Company
MECO	Maui Electric Company
NYSERDA	New York State Energy Research and Development Authority
PG&E	Pacific Gas & Electric
PRP	Preferred Resources Pilot
PV	photovoltaic(s)
SCE	Southern California Edison
SMUD	Sacramento Municipal Utility District
SOC	state of charge

Executive Summary

Distributed residential photovoltaic (PV) capacity in the United States increased from about 0.4 GW in 2010 to 10.5 GW in 2017 (GTM Research and SEIA 2018). Distributed PV and other emerging distributed energy resources (DERs) like battery storage and electric vehicles (EVs) may provide demand response, voltage regulation, and other grid services. When many DERs are aggregated and called upon to provide certain services simultaneously, they may provide the distribution grid with ancillary and other services that enhance reliability. These initiatives are often referred to as DER aggregation or virtual power plants. If nascent U.S. utility-led DER aggregation projects prove successful, new value streams could open for PV and other emerging DERs, thereby expanding deployment and transforming the energy market.

The literature on the scope, performance, and lessons learned from utility-led DER aggregation projects is limited. This report fills the research gap by surveying such programs nationwide and then analyzing five project case studies to compare lessons learned and identify common challenges and solutions that other utilities might consider when developing next-generation pilots and programs.

We identified 23 utility-led DER aggregation initiatives nationwide (Figure ES-1). The earliest project was launched by Bonneville Power Administration in 2009, while most were launched after 2014. There is significant geographic diversity in the programs; Arizona, California, and Hawaii are the only states with more than one utility-led DER aggregation program.

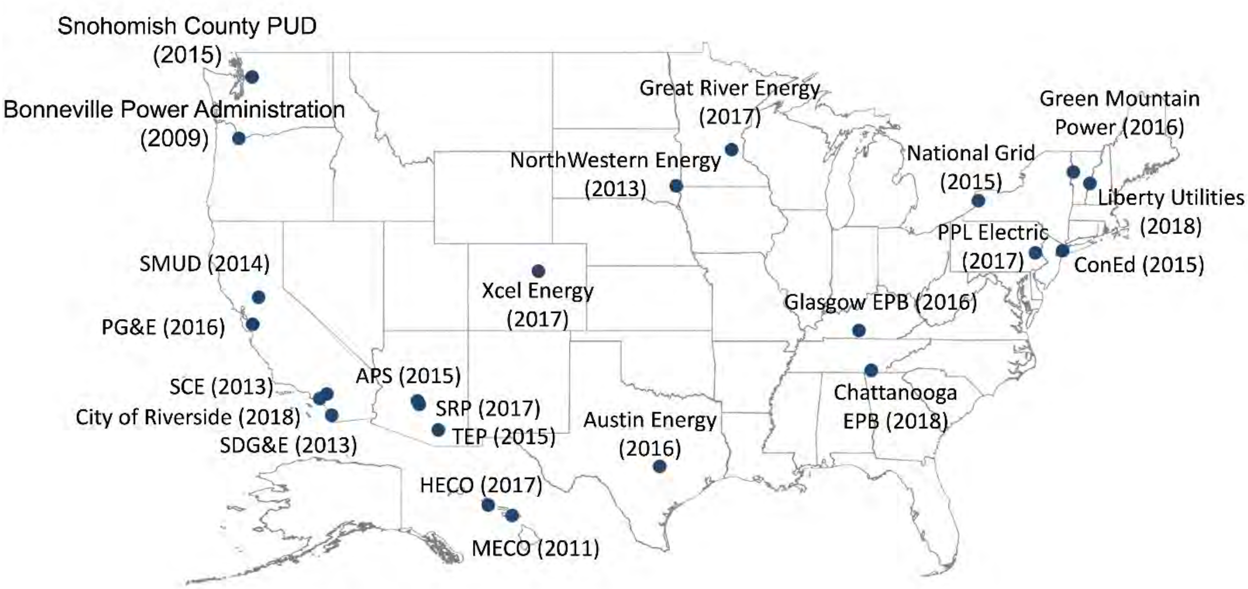

Figure ES-1. DER aggregation efforts by utility (year launched in parentheses)

We selected the following five projects as case studies, because they incorporated PV, published data on DER performance, and had diverse characteristics such as project capacity and types of DERs involved:

- Green Mountain Power – McKnight Lane Redevelopment Project

- Maui Electric Company (MECO) – JumpSmart Maui Project
- Pacific Gas & Electric (PG&E) – San Jose EPIC Distributed Energy Resource Demonstration Projects
- Southern California Edison (SCE) – Preferred Resources Pilot
- Sacramento Municipal Utility District (SMUD) – 2500 R Midtown Project

To analyze and compare the cases, we collected archival data and completed interviews with 27 subject-matter experts, including engineers, program managers, software developers, and other key partners. Overall, the unique design, scope, and timeline of each project complicates comparison of DER performance and related grid value across the projects. For example, project sizes vary from 0.04 MW of PV in the Green Mountain Power project to 51 MW in SCE's. Even so, each project demonstrated that DER aggregation can provide grid benefits including frequency response, load shifting, and voltage regulation among others. As one example, SMUD found that controlling DERs at 10 homes provided an average load reduction of 2.66 kW per house and an aggregate 44 kW of load-shifting capability at peak.

Despite project design differences, there were commonalities in the lessons learned across each project that may be of interest to other utilities considering new aggregation programs. Across the cases, we identified five categories of challenges relating to distributed energy resource management system (DERMS) development and implementation, customer acquisition, DER deployment, communication with DERs, and DER performance. In some cases, the utilities faced similar issues within a given category. For example, three of the five utilities had challenges with developing DERMS software to control a disparate set of DER technologies and participants. In other cases, the utilities' experiences and challenges varied substantially. For example, Green Mountain Power, PG&E, and SCE found that DERs performed as expected, whereas the other two utilities found that the performance of different technologies varied.

Based on this common set of challenges and the perspectives from interviewees, we offer considerations for next-generation DER aggregation programs, including the following:

- To scale DER aggregation programs, utilities likely need to develop a DERMS and find cost-effective pathways to integrate DERs with different communication protocols.
- To secure customer participation, utilities should consider how DER aggregation will impact or align with existing DER incentive structures so that potential customers see a net benefit of participation.
- To reduce deployment-related delays, utilities could work proactively with AHJs to resolve permitting issues particularly for batteries.
- To secure anticipated grid services from deployed DERs, utilities likely need to pursue methods to increase communication reliability between the utility, aggregators, and/or individual DERs.
- To more accurately predict DER performance, utilities should evaluate how technology mix, operation protocols, and consumer behavior may impact individual DER performance.

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1 Introduction

In 2010, less than 0.4 GW of distributed residential solar photovoltaics (PV) were installed in the United States. In 2017, cumulative residential PV deployment grew to 10.5 GW, representing a nearly 30-fold increase in installed capacity over that period (GTM Research and SEIA 2018). Though distributed PV generation accounts for about 0.5% of total electricity generation nationwide, high PV penetration can present localized electric grid challenges. These challenges stem from the grid's design as a one-way power flow from the utility to the end-user. The introduction of non-utility-owned distributed energy resources that export power back to the grid along with limited visibility into these assets' generation can cause unexpected backflow, voltage fluctuations, and steep demand ramps (EIA 2018; Coddington, Miller, and Katz 2016; Denholm, Clark, and O'Connell 2016).

Several mitigation options can address grid-integration challenges presented by increasing levels of PV penetration (Braff, Mueller, and Trancik 2016; Lazar 2016). This paper focuses on one strategy—aggregating multiple distributed energy resources (DERs) to create conditions that provide grid-support functions not enabled by individual DERs (Braff, Mueller, and Trancik 2016; Feblowitz 2017; Shallenberger 2017).

Though utilities have a long history of leveraging individual DERs for certain grid services, such as load control for demand response programs, utility efforts to use a broader suite of DER capabilities through aggregation are still emerging. If initial DER aggregation programs prove successful, they could enable utilities and end users to access new value streams for PV and other emerging DERs, thereby increasing DER functionality and transforming how energy is generated and delivered.

This study is one of the first efforts to document variation in aggregation programs, results, and lessons learned. To date, 23 utility-led DER aggregation projects have been implemented nationwide. We analyze five utility pilots to identify commonalities and differences in approach, scope, technology configuration, and other aspects of program design and implementation. Through personal interviews with 27 subject-matter experts and a comparative analysis, we identify key considerations, challenges, and related solutions for aggregation of PV and other DERs to inform development of next-generation programs.

The remainder of this report is structured as follows. Section 2 defines and describes DER aggregation. Section 3 surveys the utility-led DER aggregation landscape in the United States. Section 4 presents five case studies of DER aggregation projects. Section 5 summarizes the common challenges encountered across these projects and offers perspectives on possible solutions from interviewees involved in the efforts. The appendix contains a comprehensive list of all the DER aggregation initiatives implemented to date in the United States.

2 DER Aggregation in the United States

There is no universal definition of what constitutes DER aggregation, and DER aggregation programs can take a variety of forms. This section defines the types of DER aggregation considered in this report.

2.1 Defining DER Aggregation

Utilities and regional grid operators have a long history of working with residential, commercial, and industrial customers to control or manage certain DERs, typically through load control for demand response programs. In these programs, customers can opt in and provide load reduction during certain peak demand periods. This load reduction allows the utility to avoid relying on higher cost peaking generation resources, such as natural gas combustion turbines. The utility then compensates the participants for their load reductions. In 2015, about 9 GW of residential, 7 GW of commercial, and 17 GW of industrial load participated in retail demand response programs (FERC 2017).

In aggregate, the participation of numerous residential and commercial customers in demand response programs can provide significant load reduction and grid benefits to the utility. However, the contribution to load reduction on a per-customer basis is low. At the same time, participation in these programs has historically required customer time and resources that may hinder participation. To address this challenge, third-party companies have emerged to serve as intermediaries between these customers and the utility to provide demand response services at lower cost to the customer (Tweed 2010). These "aggregators" enlist residential and commercial customers in utility-sponsored demand response programs and then respond to utility calls for load reduction on behalf of the customers.

The genesis of broader DER aggregation programs has emerged from the success of these demand response programs. Demand response programs have focused on traditional load-control opportunities including adjusting heating and cooling, lighting, and manufacturing production schedules, among others. The proliferation of distributed PV, battery storage, electric vehicles (EVs), and other DERs has opened new opportunities for load shifting. In addition, these technologies—when used in certain combinations—can provide a variety of other grid-related services,[1] including the following:

- Voltage regulation, i.e., maintaining reliable and constant voltage within a transmission or distribution line to ensure electrical equipment is not damaged owing to over- or under-voltage.
- Contingency response, i.e., maintaining frequency in response to an unexpected failure or outage of a system component (e.g., generator, transmission line).
- Regulating reserves, i.e., maintaining frequency during normal (non-event) conditions.

The ability to provide these services and respond to utility requests for load control allows DER customers to deliver services similar to those offered by conventional power plants. As is the case with demand response programs, one DER customer provides fewer grid services than

[1] Providing these services may impact operation of DERs and might require different compensation structures that are not explored here.

aggregating multiple DERs and dispatching them simultaneously. This type of DER aggregation—also known as a virtual power plant—is the focus of this report.

2.2 DER Aggregation Components and Structure

Aggregation is a new paradigm that can augment traditional utility service models, but may require utility investments in dispatch platforms as well as third-party investments in control, communication, and dispatch of the aggregated DERs. Here we describe the basic components of DER aggregation and how they may be structured to provide grid services.

DER aggregation requires three fundamental components: a communication software platform, communication-capable hardware, and DERs (Figure 1). The communication software platform serves as the framework for a grid operator to send market signals to third-party aggregators, DER customers, or DERs directly. These entities can then decide whether to respond to those market signals with the requested grid service. Though many utilities have developed demand response management systems to support their peak load reduction programs, using DERs for broader grid services often requires incorporating these resources into their dispatch and distribution management systems. Some utilities have filled this need by developing new distributed energy resource management systems (DERMS) designed, in part, to manage DERs to support multiple grid and asset objectives optimally (Mulherkar 2017; Seal, Renjit, and Deaver 2018). From this software platform, the utility can directly control individual DERs, send signals to DER customers, request services of third parties, or combine all three tasks. Third-party aggregators have also developed their own communication software platforms to manage, control, and respond to utility requests. These systems are designed to interface with utility systems and maximize the value of DERs to utilities and customers.

To participate in these programs, customer-sited DERs must be equipped with communication hardware that allows the DER assets to respond to a utility, third-party aggregator, or DER customer request. This communication is often transmitted through wireless internet or mobile phone networks. The utility or aggregator transmits a signal from its software to the DER's communication hardware, which deciphers that signal and responds. Whether the DER provides the grid service is often contingent upon the priorities of the DER customer or the design of the program. Should the DER respond to the call, the communication hardware also tracks the DER's output to the grid and submits those data back to the utility or third-party aggregator. These data serve as the basis for establishing appropriate compensation. PV and batteries equipped with some types of advanced inverters are compatible with these communication pathways, as are certain "smart" home devices such as smart thermostats and EV chargers.

The third key component of an aggregation program is a fleet of DERs. A DER is any device that can be remotely controlled to consume and/or export electricity at a specified time. DERs can include PV, battery storage, EVs, smart home appliances, diesel generators, and other technologies. The type of DERs eligible to participate in aggregation may depend on the program design and other regulatory factors. For example, there may be siting, environmental, and other requirements that must be met to participate.

Though all DER aggregation programs incorporate these three components, program design and control of DERs vary widely. In some cases, the utility may directly manage all the DERs on the utility grid. In others, a utility may send market signals to aggregators and DER customers, which then respond and dispatch DERs to meet the utility's needs. The intent here is not to document exhaustively the various programmatic structures that could be employed for DER aggregation. Instead, we offer one illustrative example that demonstrates the DER aggregation concept, as summarized in Figure 1.

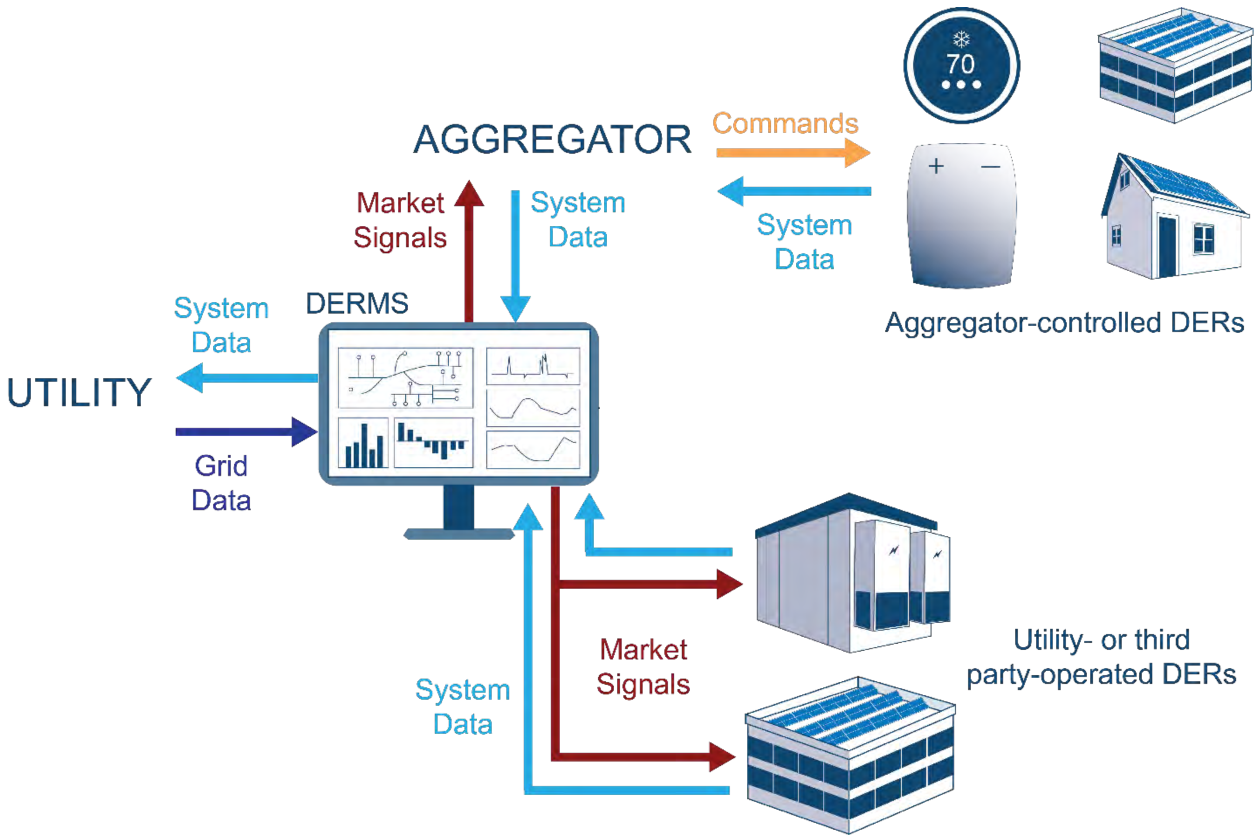

Figure 1. Example DER aggregation program structure and component interaction

In this example, the utility manages a DER aggregation program through a DERMS platform. The DERMS, which has access to grid conditions, sends market signals to an aggregator as well as individual DERs on the system. The aggregator then sends commands to participant DERs to respond to the call from the DERMS. The aggregator collects the individual DER performance data and submits those data back to the utility via the DERMS. In addition, the individual DERs participating in the program respond to the DERMS command based on the priorities of the individual DER customer. The system data are then transmitted back to the DERMS, and the utility compensates the aggregator and other relevant DER customers based on system performance.

3 DER Aggregation Program Landscape in the United States

DER aggregation programs are relatively new, with the first successful pilot launched in Germany in 2008 (Patel 2012, Feblowitz 2017). Since then, utilities from Australia to the United States have been experimenting with DER aggregation (Reuters 2018, Colthorpe 2017). However, the broad spectrum of DER aggregation initiatives has not been centrally documented and tracked, making it challenging to assess the scope of DER aggregation, performance, and lessons learned. This section helps address the literature gap by summarizing utility-led DER aggregation in the United States.[2]

The definition and implementation of DER aggregation can vary widely across electric utilities. For the purposes of this report, any utility effort to control and manage multiple DERs to provide grid services is considered DER aggregation. Employing this definition, we developed a national data set of utility projects and programs through a review of DER market reports, utility publications, and other materials (for the full data set see Appendix).[3]

From this approach, we identified 23 utility-led DER aggregation initiatives across the United States (Figure 2).[4] We interviewed utility representatives from 12 of the 23 DER aggregation programs to collect additional data on design, unique attributes, and lessons learned. Bonneville Power Administration and partner utilities launched the first project in 2009, and Maui Electric Company (MECO) launched the second in 2011. Following these early adopters, most subsequent DER projects were launched after 2014. Though there is significant geographic diversity in the data set, five of the projects are in California, while Arizona and Hawaii are the only other states with more than one project.[5]

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[2] Though this report focuses on utility-led aggregation, certain regional grid operators either operate or are considering DER aggregation programs, including the California Independent System Operator, PJM Interconnection, and the New York Independent System Operator (Gundlach and Webb 2018).

[3] This archival research was supported by data derived from interviewees.

[4] Some utilities may have more than one initiative to aggregate certain DERs, such as Green Mountain Power (Colthorpe 2017). Given the DERs are often integrated into one DERMS, we consider these different DER programs under one DER aggregation umbrella for this report.

[5] Utility service territories can cross state lines, which may impact how many states may be included in at least one utility-led DER aggregation program. In addition, Hawaiian Electric Industries is the parent company of both Hawaiian Electric Company (HECO) and MECO, so these two programs could be considered as led by the same parent utility.

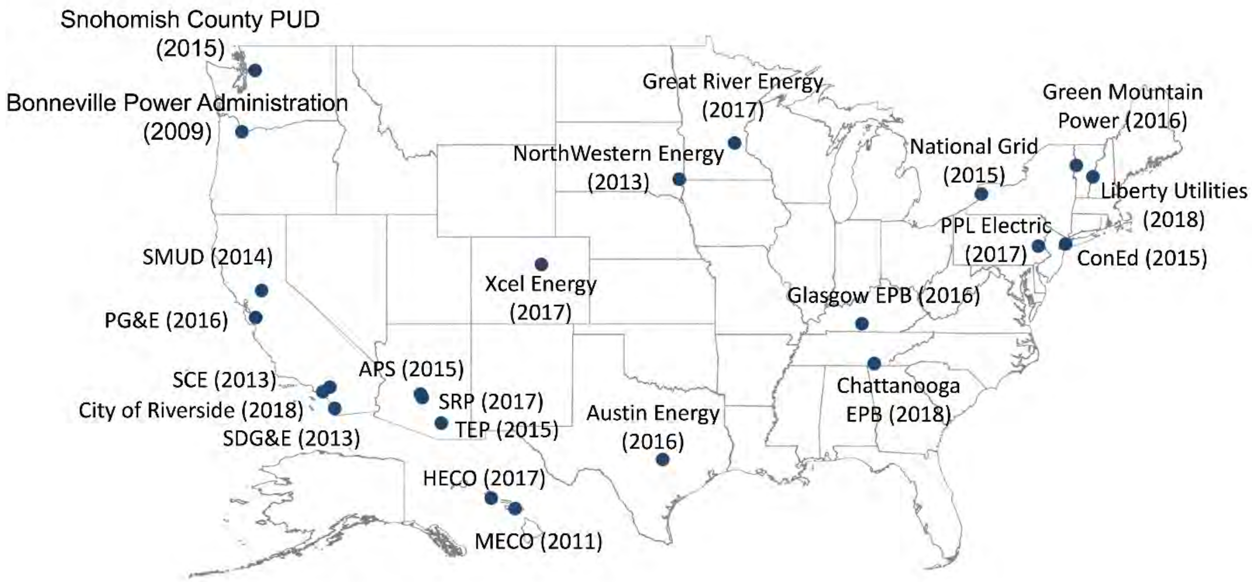

Figure 2. DER aggregation initiatives in the United States, by utility (year launched in parentheses)

Sixteen of the DER aggregation initiatives incorporate PV, while only three do not (Table 1). The remaining four projects are in varying stages of development and may incorporate PV along with other technologies when finalized. Though 13 projects couple PV with batteries, only three use a broader set of DERs including batteries, EVs, home appliances, and PV.

Table 1. DER Aggregation Programs by Select DERs

Lead Utility	PV	Batteries	Home appliances	EVs
Bonneville Power Administration*	✓	✓	✓	✓
Great River Energy	✓	✓	✓	✓
Hawaiian Electric Co.	✓	✓	✓	✓
Austin Energy	✓	✓		✓
Maui Electric Co.	✓	✓		✓
Sacramento Municipal Utility District	✓	✓	✓	
ConEd	✓	✓		
Green Mountain Power	✓	✓		
NorthWestern Energy	✓	✓		
Pacific Gas & Electric	✓	✓		
San Diego Gas & Electric	✓	✓		
Southern California Edison	✓	✓		
Xcel Energy	✓	✓		
Glasgow Electric Plant Board		✓	✓	
Arizona Public Service	✓			
Salt River Project	✓			
Tucson Electric Power	✓			
National Grid*		✓		
Snohomish Public Utility District		✓		
Chattanooga Electric Plant Board	Program in Development			
City of Riverside	Program in Development			
PPL Electric	Program in Development			
Liberty Utilities	Proposed			

PV Batteries Home appliances EVs

* Program includes other DERs, such as diesel generators, outside the scope of this report.

4 DER Aggregation Program Design and Performance

To compare the performance of grid services provision across utility-led DER aggregation programs, in this section we provide five project case studies:

- Green Mountain Power – McKnight Lane Redevelopment Project
- MECO – JumpSmart Maui Project
- Pacific Gas & Electric (PG&E) – San Jose EPIC Distributed Energy Resource Demonstration Projects
- Southern California Edison (SCE) – Preferred Resources Pilot
- Sacramento Municipal Utility District (SMUD) – 2500 R Midtown Project

We selected the five cases because they incorporate PV along with other DER technologies, and we could obtain performance data. Each project also offers variation in launch year, geography, utility type, deployed DERs, and total capacity (Table 2). This variation provides a stronger basis to assess the potential performance and implementation challenges that may be associated with DER aggregation programs across geographic and regulatory contexts. Though findings from these projects can inform broader program design, utilities will have to consider a range of implementation factors when developing long-term programs, including compensation, which are not assessed here.

Table 2. Summary Comparison of Utility Projects

	Green Mountain Power	MECO	PG&E	SCE	SMUD
Launch Year	2016	2011	2016	2013	2014
Published Performance Data	Yes	Yes	Yes	Partial	Yes
Geographic Diversity	Vermont	Hawaii	California	California	California
Utility Type	Investor-owned utility	Investor-owned utility	Investor-owned utility	Investor-owned utility	Municipal utility
Technologies Included	Batteries and PV	Batteries, EVs, and PV	Batteries and PV	Batteries and PV	Batteries, home appliances, and PV
Project PV Capacity (MW)	0.04	0.05*	0.124	51	0.08
Project Battery Capacity (MW)	0.03	0.70	4.4	67	0.20**

* MECO does not publish the rooftop PV capacity included in the pilot. This estimate assumes each participating home has a 5-kW rooftop system, consistent with the national average size.

** SMUD does not disclose the kW power rating of the batteries included in the project. This estimate assumes each battery is rated at 5 kW/11.7 kWh.

We conducted additional archival research and follow-up interviews to develop the five case studies. We used the archival data—including project reports and related materials—to describe project characteristics and results. We interviewed 27 subject-matter experts across the cases, including engineers, program managers, software developers, and other key partners.[6] The semi-structured interviews focused on identifying key challenges, solutions, and lessons learned within each case. In addition, we asked interviewees what lessons learned are most relevant across jurisdictions. The case study results are presented chronologically below by launch date: MECO, SCE, SMUD, Green Mountain Power, and PG&E.

4.1 MECO – JumpSmart Maui Project

MECO serves load on the Island of Maui, where residents are increasingly adopting distributed PV and EVs (Bucanega et al. 2016, Irie 2017). To address potential grid challenges with integrating these resources, MECO partnered with its sister utility HECO, Hitachi, and other partners to complete the JumpSmart Maui Project (2011–2016). The project had three general goals:

- Manage power quality and provide customers more access and control over energy consumption.
- Develop solutions for a high penetration of renewables on the grid.
- Maximize the use of renewable energy through DER aggregation and management.

The project had a broad scope and encompassed a wide variety of technologies (Bucanega et al. 2016). For this report, we focus on the technologies related directly to DER aggregation:

- One standalone 153-kWh lithium-ion battery
- One standalone 576-kWh lead-acid battery
- 80 bidirectional chargers[7] for EVs with 6-kW batteries at homes that already had rooftop PV
- 10 smart inverters at rooftop PV households

The DERs were managed and controlled directly by MECO's software and equipment partner, Hitachi. Hitachi developed its own DERMS—known as the Smart City Platform—to communicate directly with the batteries and EVs at participants' homes (Bucanega et al. 2016). The 10 PV systems with smart inverters were automatically controlled by the inverter to respond to voltage signals from a smart device on the local transformer. Hitachi would then dispatch the batteries and EVs in response to signals and load forecasts supplied by MECO.

[6] Ten of these interviewees were related to the PG&E case, while the remaining 17 interviews were spread across the other four cases.
[7] A bidirectional charger allows an EV to consume or export electricity to the grid.

4.1.1 Key Results

The JumpSmart Maui Project successfully demonstrated a wide variety of functions, including many related to DER aggregation. Hitachi used each DER to provide different grid services (Irie 2017).[8] The batteries demonstrated frequency response. The EVs with bidirectional chargers consumed excess electricity, including during times of higher grid-connected wind generation from 10 PM – 4 AM and PV generation from 12 – 4 PM. The EVs then discharged electricity to the grid during the peak demand period (6 – 9 PM), when renewable generation was lower. Finally, the 10 PV arrays with smart inverters provided voltage support in response to voltage signals from a local transformer.

The 80 EVs showed the most potential to maximize renewable energy consumption. Figure 3 shows EV charging before the project began (left graph) and an average day in September 2016, when Hitachi was managing EV charging (right graph). The EVs charged during the off-peak time, when wind generation was highest. The EVs then either reduced charging or were discharged at peak (6 – 9 PM) to reduce the utility's peak demand. At maximum, the EVs provided about 3 kW of peak load reduction through discharged electricity. Hitachi saw from the pilot that 14%–31% of EV batteries at homes may be available for discharge at peak times, while 2.1%–3.9% may be available for charging during peak solar generation (10 – 4 PM) (Irie 2017).

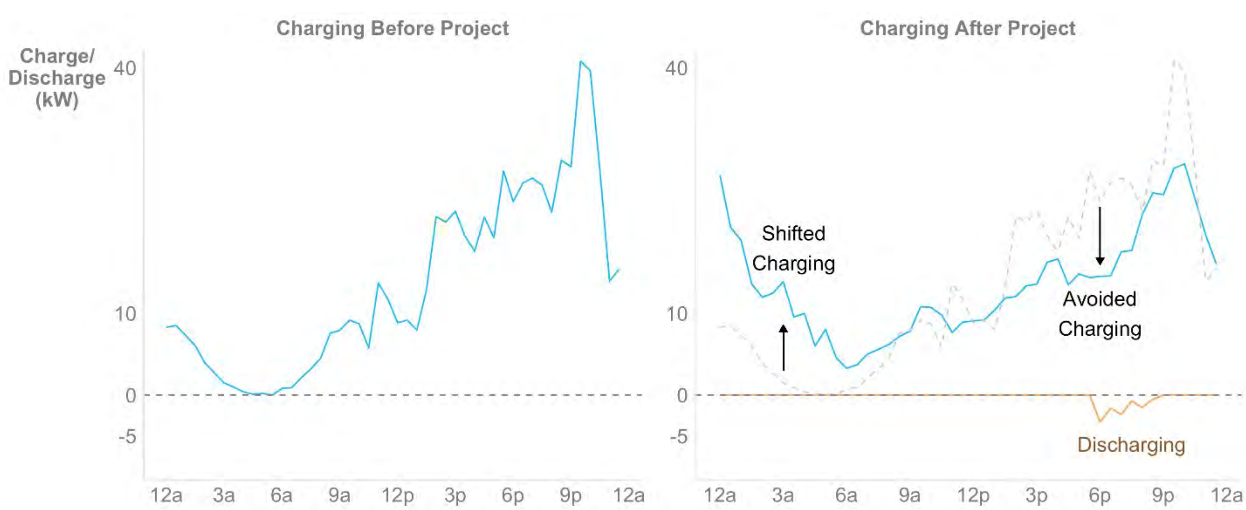

Figure 3. JumpSmart Maui Project EV load-shifting performance, September 2016 (recreated from Irie 2017)

4.1.2 Lessons Learned

For the DER aggregation components of the project, lessons learned centered around customer acquisition, PV smart inverter deployment, and use of EVs for maximizing renewable energy consumption. Hitachi and the JumpSmart Maui partners initially struggled to recruit participants, but recruitment improved after the utility developed a more robust and coordinated outreach campaign with local partners including the Maui Economic Development Board (Bucanega et al. 2016). Still, the project did not recruit enough participants to deploy PV paired with residential batteries as originally planned; interviewees explained that the reduction in net-metering

[8] More detailed results are included in a New Energy and Industrial Technology Development Organization commissioned report that is available by request in Japanese.

compensation due to using batteries, which would change the economics of residential PV, contributed to this recruiting challenge.

Implementing smart inverter technology to provide voltage support from PV was also difficult. At the time the project's smart inverter was developed, UL, a safety and quality test laboratory for commercial products, had not finalized the UL 1741 Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources.[9] This standard provides guidelines for construction standards to mitigate electrical, fire, and other hazards. Interviewees suggested that, without the standard, the equipment developer had limited guidance on how to design a smart inverter for MECO's electrical grid, which required additional time and resources.

The use of EVs to support high renewable energy penetration provided three key lessons related to communication, exporting stored electricity, and performance. First, the program relied upon one type of EV and charger, which facilitated communication with and control of the EVs. Because multiple EV and charger types are available, interviewees suggested integrating and coordinating these different models may be more challenging in future programs.

Second, the EVs were prohibited from discharging their full battery capacity (6 kW) during peak demand periods to ensure participants complied with the net-metering requirement that all exported generation consist of 100% renewable electricity. Because EVs may charge with non-renewable grid electricity, EV discharge during peak periods was limited to less than 1 kW for no more than 30 minutes from 6 – 9 PM (Irie 2017). Subsequent programs designed to capture the full value of EVs may require new tariff structures.

Finally, the ability of EVs to provide DER services depended more on charging schedules and EV locations compared with other DERs, because EVs are mobile and may not be connected to the grid when called upon. Even when EVs are connected to the grid, they may already be near full charge and thus limited in their ability to consume excess PV generation, especially during high PV generation times. Including more workplace charging in the program might result in higher EV performance, because EVs charging at work likely would have a lower state of charge compared with those charging at home during the day (Irie 2017).

4.2 SCE – Preferred Resources Pilot

In 2013, SCE was faced with planned retirements of coastal power plants in its service territory (SCE 2016). These planned retirements, along with estimates of higher urban load growth in pockets of the utility's Western Los Angeles Basin (e.g., Orange County), generated an expected need for energy resources to maintain reliable service. SCE, on its own initiative, pursued "preferred resources" (a mix of energy efficiency, load shifting, energy storage, demand response, and PV) to help offset this need. SCE launched the Preferred Resources Pilot (PRP) to understand how a diverse portfolio of preferred resources can meet local capacity needs, thereby deferring or eliminating the need for new natural-gas power plants.

The PRP was designed in three phases. Phase 1 was completed in 2014 (SCE 2018). During this phase, SCE established the pilot framework, conducted customer outreach, and began acquiring

[9] For more information on the standard, see https://standardscatalog.ul.com/standards/en/standard_1741_2.

DERs. During Phase 2, which began in 2015 and is scheduled to end in 2018, SCE will procure a total of 256 MW of DERs in the study region and of the deployed resources, measure their performance to reliably serve local area needs. Phase 3 will begin at the close of the demonstration phase in 2018 and extend through 2022. At this stage, SCE will develop sustainable processes to maintain the preferred resources to provide local capacity services. This stage will also include analyses related to the project's impact on interconnection, distribution planning, and grid operations.

4.2.1 Key Results

SCE is currently in the demonstration phase of this project and has deployed 74 MW of preferred resources in the focus region. The utility has acquired an additional 182 MW of capacity, of which 56 MW is expected to be deployed by October 2018 (SCE 2018).[10] At full buildout, energy efficiency and permanent load shifting combined will be the largest preferred resource in the pilot, followed by energy storage, demand response, and PV (Figure 4).[11]

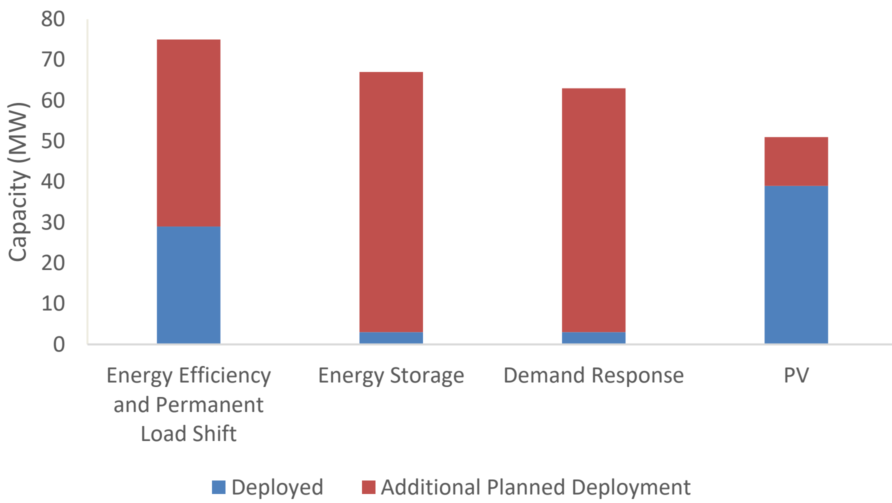

Figure 4. PRP capacity by preferred resource type

Figure 5 shows the contribution of the deployed preferred resources at peak for 2 days in August 2017. On August 3 (left graph), the resources provided approximately 50 MW of capacity during the 5-hour peak period, serving all peak demand for 2 of those hours (above a 971 MW demand baseline). On August 31 (right graph), the resources provided similar capacity at peak, but they could not meet demand for any peak hour owing to the higher load and the portfolio of resources not being fully deployed. For both days, PV served the most demand, followed by existing combined heat and power systems also located in the PRP region. As more contracted capacity comes online, including battery storage, SCE will continue to evaluate the performance of DERs and how they contribute to meeting peak demand.

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[10] SCE received regulatory approval for cost recovery of 125 MW of capacity related to the PRP on July 12, 2018 (CPUC 2018).

[11] According to interviewees, planned energy efficiency capacity is largely associated with commercial and industrial customer savings in heating, ventilation, and cooling, followed by lighting and other energy conservation measures. The demand response capacity is largely associated with additional behind-the-meter energy storage.

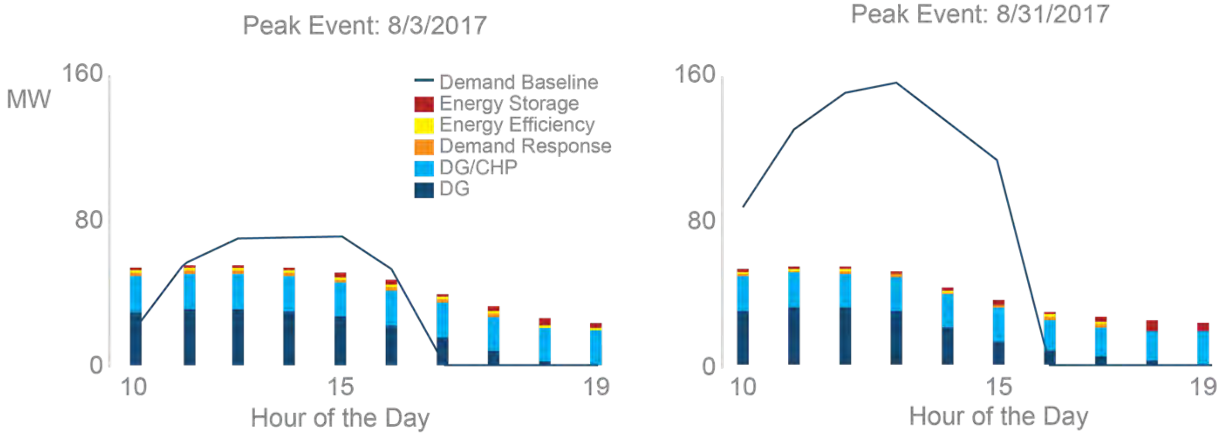

Figure 5. Assessed DER performance and customer demand for 2 days in PRP region; the demand shown is peak demand above baseline demand of 971 MW (recreated from SCE 2018)

Note: DG/CHP refers to existing distributed generation combined heat and power capacity deployed in 2015 in the PRP region. This resource was not procured for this demonstration, but it can help serve local needs and is consider part of the resource mix.

4.2.2 Lessons Learned

Lessons learned to date relate to estimating PV's capacity contribution, procuring DERs, and developing a DERMS that is compatible with DER aggregator technology. Much of the existing PV deployed on the system is behind-the-meter, and SCE's limited visibility with regard to the generation of those systems on the distribution grid makes it challenging to assess PV's contribution to local capacity needs. To address this challenge, SCE studied PV's contribution during peak times, concluding that 95% of metered systems are likely to produce at least 40% of nameplate capacity at peak (SCE 2017). Interviewees noted that this estimate will continue to be revised as the utility assesses DER performance and customer load through 2022.

Though SCE was successful in demonstrating the ability to acquire a portfolio of DERs to serve local needs, during the competitive portion of the DER acquisition process, SCE received fewer PV bids and more energy storage bids than expected. Interviewees posited that the lack of PV bids, in this highly urban area, might have been due to challenges associated with enlisting hundreds of residential customers, which makes economies of scale challenging for commercial developers. Developers may have also had challenges contracting with commercial customers who may rent their facilities and do not have the rights to install PV. At the same time, some battery storage project costs have declined (ESA and GTM Research 2018), which may have increased the number of energy storage bids. As a result, interviewees suggested it's important not to prejudge, or prescribe, a portfolio mix but instead focus on acquiring DERs to meet the specific resources attributes needed (e.g., 10 MW available for 2-4 hours on certain summer days). The goal for SCE is now to demonstrate that the resources can be deployed to meet grid needs.

Finally, developing a DERMS and communicating with DERs have also presented challenges. Interviewees said that pilot development of a DERMS is time and resource intensive. SCE is currently using a test DERMS but expects to adopt a full DERMS before the project's conclusion. Interviewees suggested that the publication of IEEE 2030.5-2018 Standard for Smart Energy Profile Application Protocol, designed to support communication between the utility and

DERs, will help address communication challenges by providing a common communication framework for control technologies.[12]

4.3 SMUD – 2500 R Midtown Project

SMUD launched and completed the 2500 R Midtown project in 2014 to test the functionality of DER control technology in providing grid benefits. SMUD's key partners for the 2500 R Midtown project included Sunverge Energy Inc., ThinkEco, and Pacific Housing Inc. (ADM Associates Inc. 2014).[13] The project included 34 newly constructed single-family homes outfitted with a 2.25-kW PV array, an 11.7-kWh lithium-ion battery, a smart thermostat, and a "modlet."[14] SMUD then used subsets of these homes to test the following use cases:

- Load shifting: demonstrate the ability of the DERs to offer bill savings throughout the program period by shaving or shifting load at peak times.
- Fleet operation in aggregate: demonstrate the ability to coordinate multiple homes with DERs to operate as a group.
- Uninterruptible power source: demonstrate PV and battery islanding functionality to provide backup power to critical load during a grid outage and successfully reconnect to the grid.
- Power quality: demonstrate that the PV and battery operate in acceptable voltage, frequency, and harmonic distortion ranges.
- PV firming: demonstrate that the PV and battery mitigate rapid output changes from PV panels.
- Regulation: demonstrate that the PV and battery can respond to regulation pulse signal and adjust load delivery.

4.3.1 Key Results

The project successfully demonstrated all six use cases prior to completion in December 2014. From a DER aggregation perspective, the first two use cases—load shifting and fleet operation—are the most applicable and occurred in tandem. Ten of the 34 homeowners volunteered to participate in a time-of-use rate schedule and have their DERs controlled directly by SMUD. SMUD operated these 10 homes as a fleet to provide load-shifting services during "conservation days"—12 of the highest peak demand days on SMUD's system. On each conservation day, SMUD required the battery to store midday PV generation and discharge that electricity during the peak period (4 – 6 PM). The smart thermostat cooling set point was lowered prior to the peak period to precool the home, and it was raised during the peak period to reduce air conditioning load. Finally, the power to appliances plugged into modlets was turned off during the peak period.

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[12] For more information on the standards, see https://standards.ieee.org/findstds/standard/2030.5-2018.html.
[13] For more information on pilot studies completed after those articulated in ADM Associates Inc. (2014), see Energy and Environmental Economics Inc. (2016).
[14] A modlet refers to a 120-volt wall outlet device that can be remotely activated to control electricity flow to the appliances plugged into the outlet (ADM Associates Inc. 2014).

On an average conservation day, the 10 homes shifted a maximum of 43.8 kW during the peak period (Figure 6). The average home provided 2.66 kW of demand savings during a conservation day. The PV and battery provided most of this load shift at 2.47 kW, followed by the smart thermostat (0.18 kW) and the modlet (0.004 kW) (ADM Associates Inc. 2014).

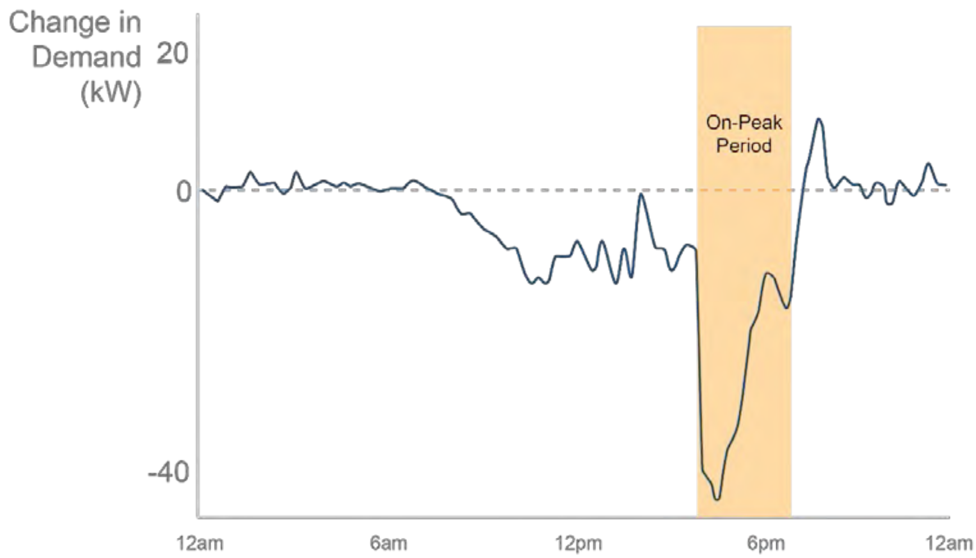

Figure 6. Total household fleet load-shifting profile for an average conservation day (recreated from ADM Associates Inc. 2014)

4.3.2 Lessons Learned

Lessons learned relate to integrating DERs into a DERMS platform, siting and performance of certain DERs, communication with those DERs, and considerations for next-generation DER aggregation programs. In the context of DERMS development and DER integration, one interviewee noted that communicating with specific third-party platforms was not the key challenge; rather, it was difficult to identify cost-effective pathways to manage integration and data exchange across the utility and third-party platforms. The interviewee suggested that DERMS technology improvements have made this easier, but open communication platforms will be hindered by third-party interests to protect proprietary information.

Local authorities having jurisdiction (AHJs) had limited understanding of customer-sited battery storage, which required SMUD and project partners to work with these authorities to ensure battery systems could be sited at the new homes. One interviewee suggested that, although these discussions did not delay the overall project timeline, they may have caused delays if construction required a faster timeline.

SMUD questioned the value of smart thermostats and modlets as implemented in the project. Smart thermostat performance was inconsistent, and the cooling data were not fully available, prompting SMUD to call for additional analysis into the value of these resources. The modlets typically provided very low demand response capacity, because the plugged loads were small and consumed less than 2 W of power 80% of the time (ADM Associates Inc. 2014).

The project also generated considerations for future programs. An interviewee noted that participating homeowners were sent manually generated emails calling for a conservation day, and a larger program would require an automated system for both customer notice and dispatch. In addition, SMUD suggested that DERs might provide regulation services, but more analysis was needed to verify that response and increase confidence in DER capacity (ADM Associates Inc. 2014). Finally, SMUD suggested that the six demonstrated use cases may serve different or cross purposes. As a result, the utility might benefit from developing a use-case prioritization process (ADM Associates Inc. 2014). The design of this prioritization process might impact the value to the end-use customer, which could influence customer interest in next-generation programs.

4.4 Green Mountain Power – McKnight Lane Redevelopment Project

In 2016, the McKnight Lane Redevelopment project replaced 14 manufactured housing units with seven net-zero energy modular duplex-homes in Waltham, Vermont. Green Mountain Power was a key partner in the project along with Addison County Community Trust, Sonnen, and the Vermont Community Development Program, among many others (Donalds, Galbraith, and Olinsky-Paul 2018). The seven modular duplexes were equipped with a 6-kW PV array, a 4-kW/6-kWh lithium-ion battery, and various energy efficiency measures such as heat pump water heaters and cold climate heat pump compressors.[15] Green Mountain Power then communicated with the battery systems via a DERMS platform developed by Virtual Peaker (Ferreira 2016).

The project's goals spanned affordable housing, air quality, and DER aggregation. As to DER aggregation, the project had three key objectives:

- Peak demand reduction: demonstrate PV and battery system capacity to reduce annual and monthly peak demand from ISO New England.
- Energy arbitrage: deploy battery systems in the ISO New England day-ahead and real-time markets to buy and sell energy.
- Transmission and distribution upgrade deferral: demonstrate PV and battery benefit in alleviating congestion and thereby offsetting the need for infrastructure upgrades.

4.4.1 Key Results

The McKnight Lane Redevelopment project has met two of its three DER aggregation goals, including peak load reduction and transmission and distribution upgrade deferral.[16] Because the battery systems represent a comparatively small load, Green Mountain Power has not disclosed a quantitative infrastructure-deferral benefit, though it does plan to assess this value (Ferreira 2016; Donalds, Galbraith, and Olinsky-Paul 2018). In any case, peak demand reduction is the utility's highest-priority value proposition, so those results are shown here.

Green Mountain Power planned to use the battery systems for annual and monthly peak demand reduction. Because ISO New England experienced an unusually early annual peak demand event

[15] One unit was equipped with a 4-kW/8-kWh lithium-ion battery (Donalds, Galbraith, and Olinsky-Paul 2018).
[16] The utility is still implementing the energy arbitrage component of the project (Donalds, Galbraith, and Olinsky-Paul 2018).

on June 13, 2017, Green Mountain Power was unable to deploy the battery fleet to serve this peak (Ferreira 2016; Donalds, Galbraith, and Olinsky-Paul 2018). However, it successfully discharged the batteries to reduce monthly peak demand. Specifically, Green Mountain Power dispatches the battery fleet for 2 hours to align with the typical 2-hour duration of peak demand events for ISO New England (Figure 7), resulting in an aggregate demand reduction of 44.65 kW (Ferreira 2016).[17] This load reduction represents a $350–$400 monthly cost savings on behalf of all ratepayers (Donalds, Galbraith, and Olinsky-Paul 2018).

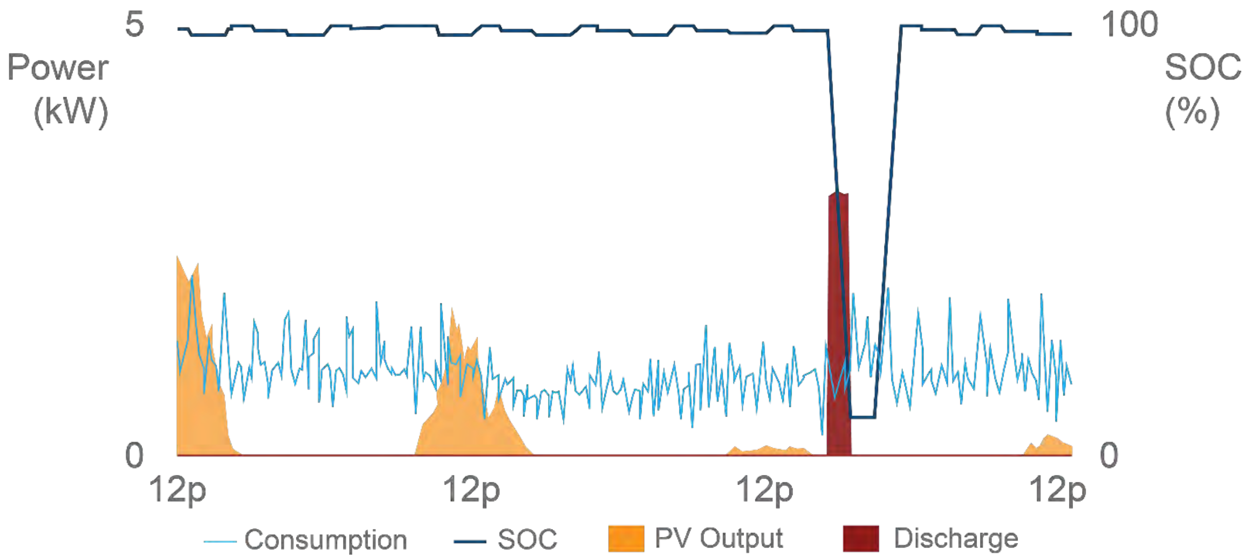

Figure 7. Battery and PV operation from one duplex around the monthly ISO New England peak period, February 2018 (recreated from Donalds, Galbraith, and Olinsky-Paul 2018)

Note: SOC refers to battery state of charge

4.4.2 Lessons Learned

The McKnight Lane Redevelopment project provides lessons learned about communicating with DERs, deploying DERs to meet peak demand, and developing a DERMS to manage a variety of DERs.[18] The utility experienced challenges with establishing communication between the batteries and the DERMS, stemming in part from battery or inverter hardware issues (Donalds, Galbraith, and Olinsky-Paul 2018). In some cases, these challenges required replacing the equipment. Once the batteries were deployed and communication systems tested, the utility still faced communication issues when calling on the batteries to respond. This required frequent visits back to the site to reestablish communication (Donalds, Galbraith, and Olinsky-Paul 2018). Interviewees suggested that some issues related to communication with the modems that controlled the batteries. These modems also had to be reset manually, adding delay and cost. Technology innovation and minimizing links in the chain of communication were both sited by interviewees as methods to improve communication reliability in future programs.

[17] While peak demand shaving is a priority for Green Mountain Power, the utility ensures that the battery fleet always maintains a minimum 10% state of charge to allow for backup power provision in the event of a grid outage.
[18] For a broader discussion of lessons learned in relation to the goals of this project, see Donalds, Galbraith, and Olinsky-Paul (2018).

Using batteries to offset peak demand also has entailed challenges. Green Mountain Power's manual programming of the batteries increased time and resource requirements. Automating the system should reduce time and resource requirements and may help time battery discharge to meet difficult-to-predict peak demands without the need for improved peak forecasting methods. Green Mountain Power plans to automate activities related to peak demand reduction and energy arbitrage going forward (Donalds, Galbraith, and Olinsky-Paul 2018). Employing this manual process, the utility ultimately failed to meet its annual peak load reduction objective, given the unpredictable nature of the peak. As a result, without improved forecasting methods and tools, a utility may be unable to use DERs to reliably provide peak reduction. Nevertheless, when the utility did successfully predict peak, the DERs performed as expected.

Finally, the project has demonstrated the complexities of developing a DERMS system. An interviewee commented that DERMS developers have different processes and timelines for incorporating resources. Thus, it was important to select a vendor that provided functionality and a timeline aligned with utility goals.

4.5 Pacific Gas & Electric – San Jose EPIC Distributed Energy Resource Demonstration Projects

In 2016, PG&E launched the San Jose Distributed Energy Resource Demonstration Projects composed of three collocated research projects supported by the California Energy Commission, project 2.02, 2.03A, and 2.19 (PG&E 2017). This case study focuses on Project 2.02 Distributed Energy Resource Management System. For this project, PG&E had three partners: General Electric (GE), Tesla, and Green Charge Network (GCN) (PG&E 2016). Through this project, PG&E aimed to field-validate core DERMS capabilities in a high-penetration DER environment. GE developed the proof of concept DERMS platform, while Tesla and GCN served as the aggregators for 124 kW of residential PV, 66 kW of residential lithium-ion battery storage in 27 homes, and 360 kW of commercial lithium-ion battery storage at 3 commercial locations (Ardani et al. 2018). PG&E also incorporated a 4-MW PG&E-owned sodium sulfur battery in the demonstration project.

The project tested six DERMS-related use cases:

- Provide situational awareness of actual and forecasted DER-related grid conditions in real time.
- Manage equipment capacity constraints by coordinating DERs to mitigate overload issues.
- Mitigate voltage issues by controlling the real and reactive power output of DERs.
- Dispatch DERs based on economic factors such as costs and external price signals.
- Improve operational flexibility by developing forecasts and optimizations during abnormal switching configurations through DERs.
- Demonstrate coordination of behind- and in-front-of-the-meter DERs to provide distribution grid services and bid into wholesale markets.

4.5.1 Key Results

Though full results are not yet public, PG&E's early results indicate the potential viability of all six use cases at demonstration scale (Ardani et al. 2018). The DERMS has successfully integrated load and PV generation forecasts to anticipate current and future demand requirements. In line with this situational awareness, the DERMS has predicted capacity constraints and voltage violations on the system and dispatched DERs to mitigate these issues. A comprehensive summary of PG&E's project, including the quantitative results associated with each use case will be published in 2018 (Ardani et al. 2018). Here, we offer one illustrative example of the DERMS deploying DERs to mitigate a forecasted overload situation. Figure 8 demonstrates that the DERMS estimated an overload on the system at about 8 PM, after PV generation declines and demand peaks. The DERMS compensated for this estimated overload by charging batteries during peak generation and discharging those batteries to address the overload situation.

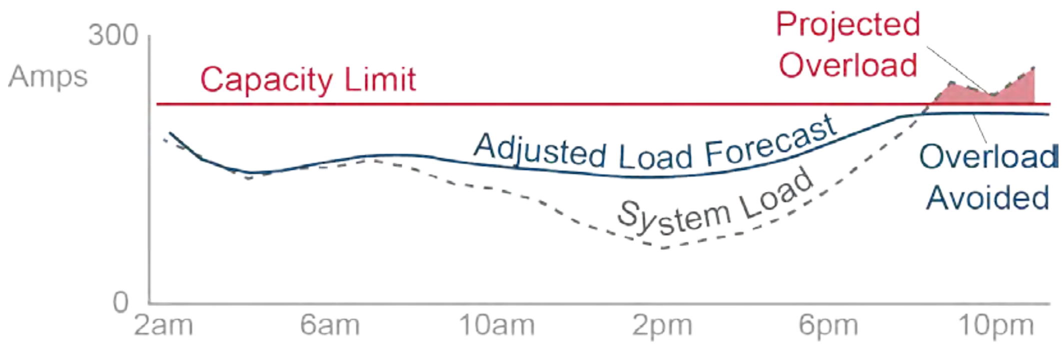

Figure 8. Example of DERMS-forecasted overload mitigation (recreated from Portilla 2017)

4.5.2 Lessons Learned

PG&E's efforts offered a variety of insights and the focus here is on some of the key lessons relating to software development and integration, customer acquisition, DER deployment, and DER communication. PG&E was interested in working with multiple third-party aggregators to better understand differences in aggregator performance and the complexity associated with integrating these aggregators into one DERMS software platform (Ardani et al. 2018). Working with multiple aggregators provided benefits relating to collaboration and problem solving as well as diversifying DERs. However, the utility faced challenges with coordinating these aggregators and incorporating different sets of communication standards within the DERMS platform. These challenges can add time and cost to the program. The utility addressed some of this challenge by implementing the use cases in sequence from less to more complex. This allowed the utility to build on lessons learned at each stage and address points of failure before adding complexity. In order to scale these types of programs in the future, further standardization of protocols and operational practices will be required.

PG&E also faced unexpected customer-acquisition challenges, in part because the project needed to recruit non-PV customers because the original hardware configuration made retrofits difficult (Ardani et al. 2018). Now that homes with PV systems can be more easily retrofitted with batteries due to hardware innovation, this challenge may be mitigated in other locations. For those customers that did sign up, PG&E faced unanticipated permitting and interconnection challenges (PG&E 2018a). PG&E noted that the City of San Jose had limited experience permitting solar plus battery systems resulting in a lack of standardization and streamlined permitting processes. As a result, each system was addressed individually and often required multiple inspections, which added to construction timelines (PG&E 2018a).

Once the DERs were deployed, PG&E faced challenges with communicating with remote DERs. Residential internet connections served as the communication link between PG&E and the DERs and these connections were not always consistent (PG&E 2018b). In addition, PG&E found some cases of incorrect data or gaps in reported data particularly when batteries were tripped offline. Some of these challenges were resolved in the longer than expected acceptance testing stage, but others persisted throughout the demonstration such as challenges relating to inconsistent internet connections.

Finally, PG&E was pleased with the DERMS demonstrated capability to maximize DER performance for distribution and wholesale markets. First, the DERMS allowed PG&E to aggregate multiple assets with shared characteristics into groups termed “nodes” (Ardani et al. 2018). PG&E could communicate with and deploy these nodes as one aggregated resource within the DERMS to provide certain grid services. This allowed the utility to more effectively address challenges in certain geographies and deploy resources that are most appropriate for certain grid services. In addition, PG&E found the DERMS could coordinate DERs participating in both distribution and wholesale markets. Building out this functionality, would be important to scale and coordinate DER activity across these different markets to maximize grid value (Ardani et al. 2018).

5 Conclusions

Despite the unique context of each DER aggregation project, the pilots shared common challenges relating to DERMS development and implementation, customer acquisition, DER deployment, communicating with DERs, and DER performance. This section summarizes those challenges, the key lessons learned, and considerations for resolving these issues in the next generation of programs.

Table 3 summarizes the challenges faced by each of the utilities in relation to five categories. In some cases, the utilities faced similar issues within a given category. For example, three of the five utilities had challenges with developing DERMS software to control a disparate set of DER technologies and participants. In other cases, the utilities' experiences and challenges varied substantially. For example, Green Mountain Power, PG&E, and SCE found that DERs performed as expected, whereas the other two utilities found that the performance of different technologies varied. Though these challenges can be interrelated, the remainder of this section discusses each challenge separately with perspectives from interviewees on how utilities might resolve each challenge.

Table 3. Summary of Key DER Program Challenges by Utility and Category

Key Challenge	**MECO**	**SMUD**	**Green Mountain Power**	**SCE**	**PG&E**
DERMS Development and Implementation		Software compatibility		Software compatibility	Software compatibility
Customer Acquisition	Securing participants				Securing participants
DER Deployment	Battery uptake and inverter design	Storage permitting			Storage permitting and interconnection
Communicating with DERs		DER data communication gaps	Establishing initial communication	DER data communication gaps	DER data communication gaps
DER Performance	EV performance varied	Home appliance performance varied			

To scale DER aggregation programs, utilities likely need to develop a DERMS and find cost-effective pathways to integrate DERs with different communication protocols. In all five cases, the utility, or its partners, developed a temporary or permanent DERMS to aggregate and deploy DERs. A DERMS likely will be essential to scale aggregation programs given the need to develop situational awareness of DER performance, the ability to securely and reliably interact with those DERs, and optimally dispatch them to provide grid services autonomously. The cases demonstrate that developing a DERMS can be challenging, but Green Mountain

Power and PG&E's approach to phase in DERMS functionality may help mitigate some of these challenges. This approach could serve as a model for other utilities. Interviewees also offered some perspective on how utilities might address integration challenges, particularly when developing a program that includes DER aggregators. Ensuring the DERMS can interact with aggregator software adds complexity, costs, and cybersecurity concerns (Rodriguez Labastida and Asmus 2018). Interviewees suggested that aggregator software platforms are just emerging, so technology innovation may streamline the time and resources needed to develop, test, and integrate these systems. Several interviewees suggested that the use of open communication standards may also help developers and aggregators integrate disparate DER technologies regardless of their make and model. The IEEE 2030.5 Standard for Smart Energy Profile Application Protocol is one effort to standardize communication protocols between the utility, aggregators, and individual DERs. Widespread adoption of similar open or standardized communication protocols may reduce the time and resources needed to develop and implement a DER aggregation program.

To secure customer participation, utilities should consider how DER aggregation will impact or align with existing DER incentive structures so that potential customers see a net benefit of participation. The MECO and PG&E cases both demonstrate the potential challenges with acquiring customers. Location, availability, and concentration of DERs are essential considerations for assessing the role these resources can play in providing grid value. Utilities need to balance these considerations and related value, with existing DER incentive structures to gauge potential customer interest in DER aggregation. MECO's project partner, Hitachi, and PG&E faced customer-acquisition challenges. In the case of Hitachi, these challenges stemmed in part from the poor economic value proposition of PV and batteries compared with net-metered PV on MECO's grid. As a result, utilities may need to seek alternative rate or other compensation structures to foster customer interest in DER aggregation programs. If customers do not see a reasonable return, they will be unlikely to participate. Interviewees also suggested that utilities should adequately explain program design and requirements before signing up customers to ensure that the customers make informed choices. Other utilities might wish to evaluate these factors prior to program adoption and then adjust their customer-acquisition process or program design accordingly.

To reduce deployment-related delays, utilities could work proactively with AHJs to resolve permitting issues particularly for batteries. Hitachi did not deploy enough residential batteries to test this deployment challenge in the MECO pilot, while SMUD and PG&E faced AHJ permitting challenges. Battery permitting uncertainty can cause delays and additional costs as was the case for PG&E and SMUD. Though not evident in our cases, these challenges can also result in project termination. For example, Consolidated Edison's (Con Ed's) Clean Virtual Power Plant in New York was terminated after the utility could not secure approval from the New York City Department of Buildings and the New York Fire Department to install residential batteries. Con Ed remained committed to this concept and conducted a battery storage safety analysis to provide permitting authorities with more information on safe battery siting in New York City (Con Ed 2017). In addition, the New York State Energy Research and Development Authority (NYSERDA) has offered $8.1 million in technical assistance to support the development of energy storage permitting guidelines, model codes, and standards to streamline future permitting costs (NYSERDA 2016, NYSERDA 2018). These initiatives are similar to ongoing efforts to streamline PV permitting process and may help other utilities that are considering incorporating batteries in their DER aggregation programs.[19] Even so, utilities and other DER aggregation partners may wish to discuss battery storage deployment and permitting requirements with AHJs early in the process to address and resolve permitting issues.

To secure anticipated grid services from deployed DERs, utilities likely need to pursue methods to increase communication reliability between the utility, aggregators, and/or individual DERs. Four utilities faced communication challenges with deployed DERs. For example, Green Mountain Power encountered issues with faulty equipment, limited communication, and the need to reset equipment manually (Donalds, Galbraith, and Olinsky-Paul 2018). In addition, interviewees from this case suggested that failures in the communication chain between the individual DER, the aggregator, and the utility also impacted DER performance. Ongoing efforts to streamline communication chains could help reduce the probability of failure. PG&E, SMUD and SCE also had issues with the data they received in response from DERs, even with consistent lines of communication as demonstrated by SMUD and SCE. Utilities may want to consider these types of challenges when determining which DERs to include in their programs and when developing data-communication requirements for DERs to receive compensation for grid services.

To more accurately predict DER performance, utilities should evaluate how technology mix, operation protocols, and consumer behavior may impact individual DER performance. Hitachi found that EV capacity varied depending on the time of day, which was due in part to the mobile nature of EVs and the MECO project's focus on residential charging (Irie 2017). In comparison, SMUD found that smart thermostats in its program offered inconsistent demand response (ADM Associates Inc. 2014). The utility could not confirm what caused this variation, given the lack of data, and said more research was necessary to understand how reliable these resources could be (ADM Associates Inc. 2014). Thus, utilities may want to consider how DER technology performance may vary in their programs and adjust program design as necessary.

[19] For more information on ongoing efforts to streamline permitting and construction processes for PV see Day and Aznar (2018).

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Appendix

Table 4. Identified Utility-led DER Aggregation Programs by Year

Project Name	Launch Year	State	Lead Utility	Technology Summary
Pacific Northwest Smart Grid Demonstration Project	2009	Oregon	Bonneville Power Administration	Batteries, EVs, home appliances, PV
JumpSmart Maui	2011	Hawaii	Maui Electric Company	Batteries, EVs, home appliances, PV
Distributed Energy Resource Management System	2013	California	San Diego Gas & Electric	Batteries, PV
NA	2013	South Dakota	NorthWestern Energy	Batteries, PV
Preferred Resources Pilot	2013	California	Southern California Edison	Batteries, PV
2500 R Midtown	2014	California	Sacramento Municipal Utility District	Batteries, home appliances, PV
Energy Storage Program	2015	Washington	Snohomish County Public Utility District	Batteries
Distributed System Platform Demonstration Project	2015	New York	National Grid	Batteries, fossil generators
Clean Virtual Power Plant Demonstration Project	2015	New York	Consolidated Edison	Batteries, PV
Solar Partner Program	2015	Arizona	Arizona Public Service	PV
Residential Solar Program	2015	Arizona	Tucson Electric Power	PV
Glasgow Smart Energy Technologies	2016	Kentucky	Glasgow Electric Power Board	Batteries, home appliances
Austin SHINES	2016	Texas	Austin Energy	Batteries, PV
McKnight Lane Project	2016	Vermont	Green Mountain Power	Batteries, PV
San Jose Distributed Energy Resource Demonstration Project	2016	California	Pacific Gas & Electric	Batteries, home appliances, PV
Advanced Inverter Pilot	2017	Arizona	Salt River Project	PV
Community Storage Project	2017	Colorado	Xcel Energy	Batteries, PV

HECO DR Portfolio	2017	Hawaii	Hawaiian Electric Company	Batteries, EVs, home appliances, PV
Keystone Solar Energy Future Project	2017	Pennsylvania	PPL Electric Utilities	TBD
NA	2017	Minnesota	Great River Energy	Batteries, EVs, home appliances, PV
CleanstartDERMS	2018	California	City of Riverside Public Utilities	TBD
Distributed Energy Resource Management System	2018	Tennessee	Chattanooga Electric Power Board	TBD
Battery Storage Pilot Program	2018	New Hampshire	Liberty Utilities	Proposed, TBD

Distribution Planning Regulatory Practices in Other States

Lisa Schwartz
Electricity Markets and Policy, Berkeley Lab

Oregon Public Utility Commission Webinar
May 21, 2020

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In This Presentation

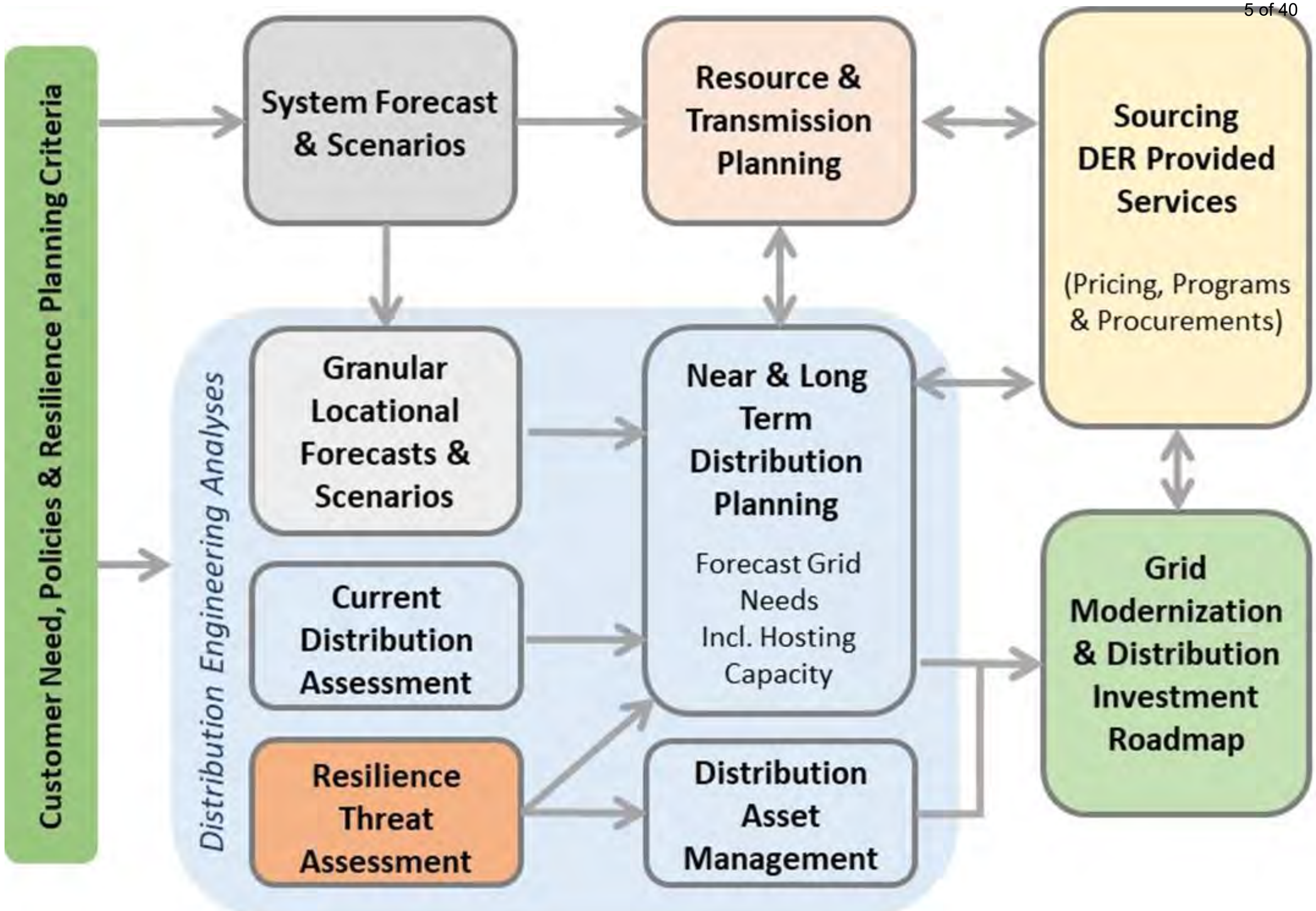
- Electricity planning and state interests, activities and considerations
- Example state objectives, requirements, and elements for distribution system plans that include distributed energy resources (DERs)
- Example state-specific approaches
- Non-wires alternatives (NWAs): state procurement strategies
- Resources for more information

Electricity Planning and State Interests, Activities and Considerations

Electricity Planning Activities

- Distribution planning - Assess needed physical and operational changes to local grid
  - Annual distribution planning process
    - Identify and define distribution system needs
    - Identify and assess possible solutions
    - Select projects to meet system needs
  - Long-term utility capital plan
    - Includes solutions and cost estimates, typically over a 5- to 10-year period, *updated every 1 to 3 years*
- Integrated resource planning (IRP) - Identify future investments to meet bulk power system reliability and public policy objectives at a reasonable cost
  - Consider scenarios for loads and DERs; impacts on need for, and timing of, utility resource investments
- Transmission planning – Identify transmission expansion needs and options

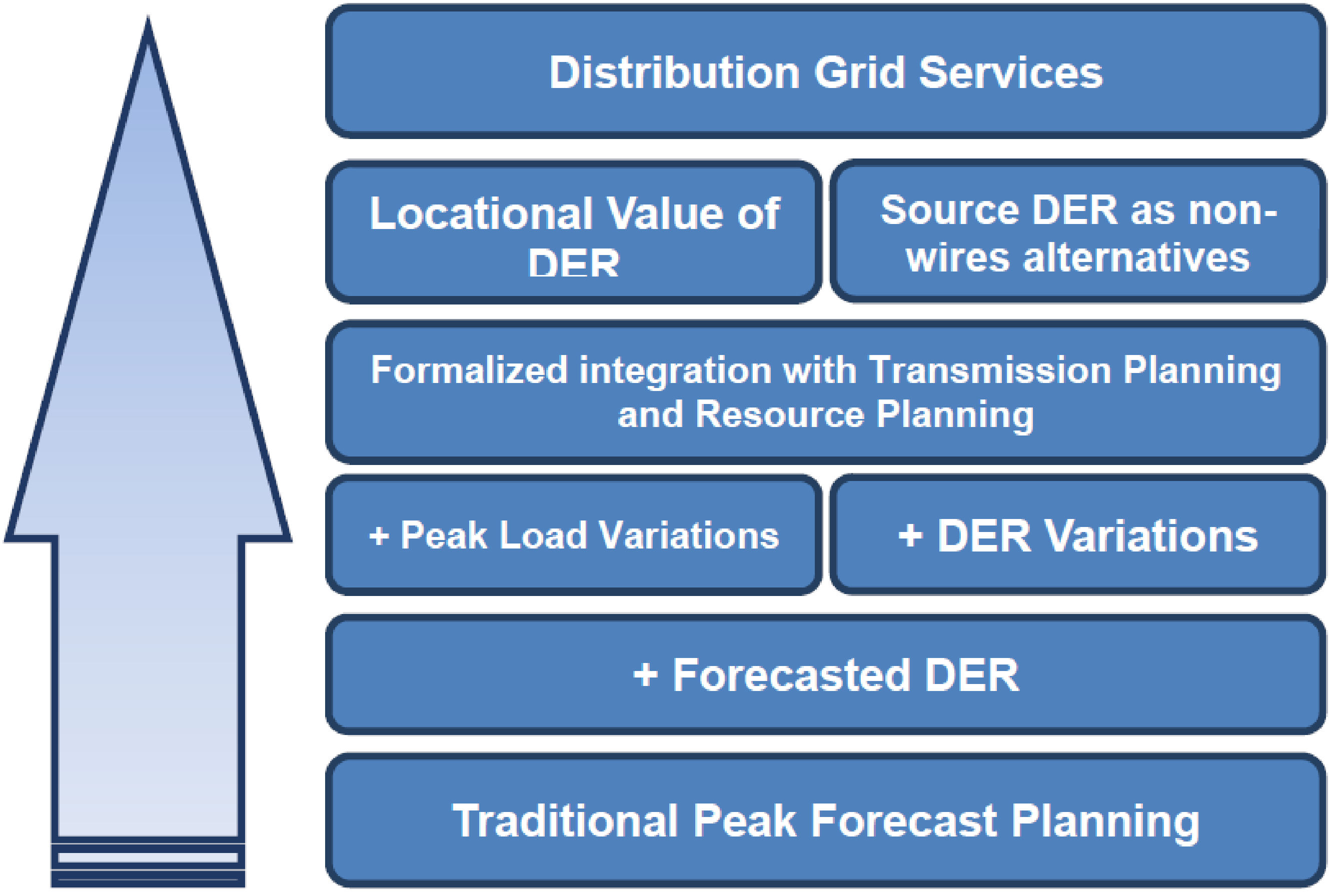
Integrated Grid Planning



See DOE's Modern Distribution Grid initiative

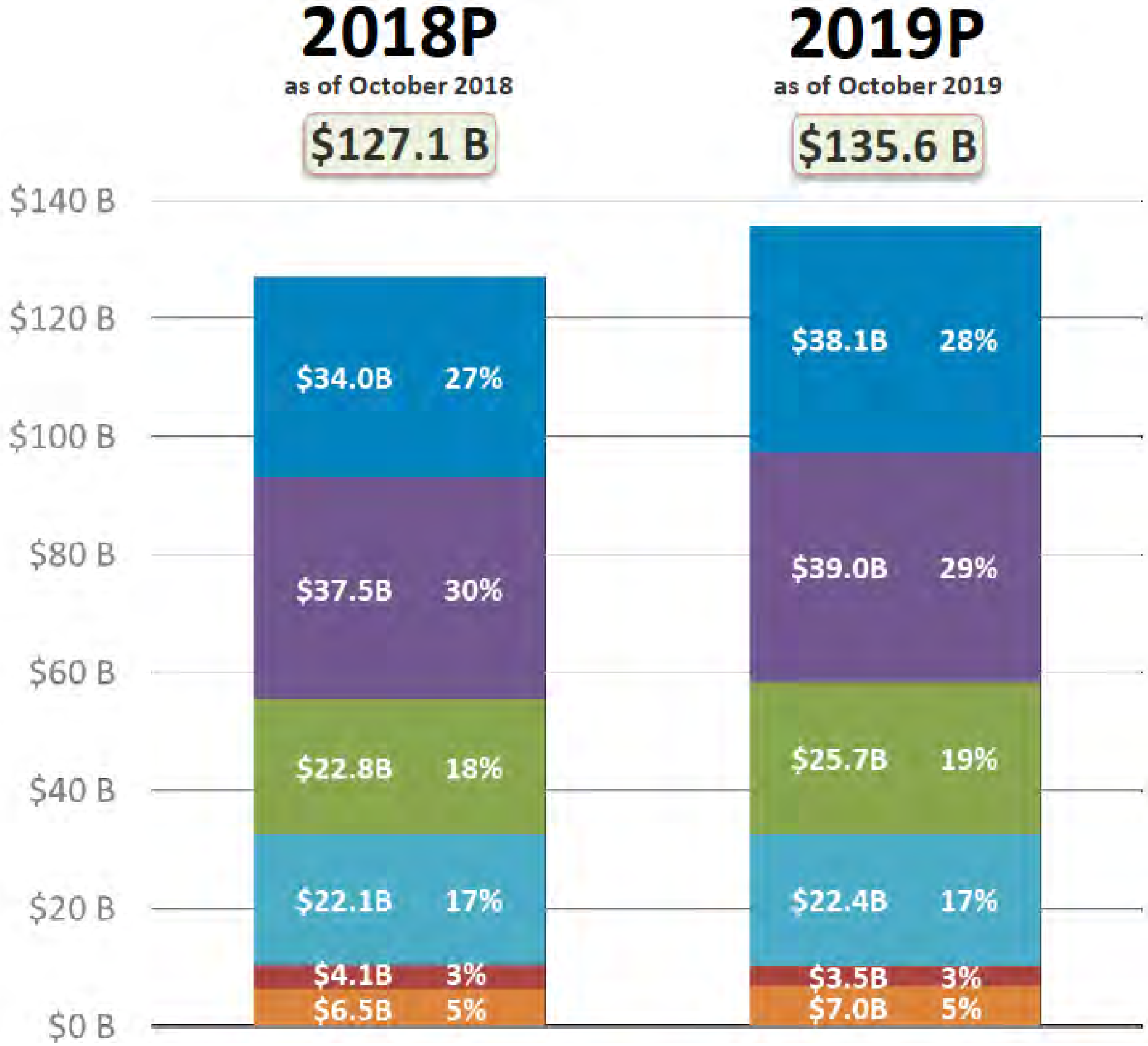
Adapted from P. De Martini, *Integrated Distribution Planning*, ICF

Evolution in Distribution Planning Practices



Source: Xcel Energy, Integrated Distribution Plan, Nov. 1, 2019

One Reason States Are Increasingly Interested in Distribution System Planning



Distribution system investments account for the largest portion (29%) of capex for U.S. investor-owned utilities: $39B (projected) in 2019

Source: [Edison Electric Institute]

States are responding to a variety of drivers for modernizing the distribution planning process.

- More DERs deployed — costs down, policies, new business models, consumer interest
- Resilience and reliability (e.g., storage, microgrids)
- More data and better tools to analyze data
- Aging grid infrastructure and utility proposals for grid investments
- Need for greater grid flexibility in areas with high levels of wind and solar
- Interest in conservation voltage reduction and volt/VAR optimization
- Non-wires alternatives to traditional solutions may provide net benefits to customers

Other Potential Benefits From Improved Distribution Planning

- Makes transparent utility plans for distribution system investments, holistically, before showing up individually in a rider or rate case
- Provides opportunities for meaningful PUC and stakeholder engagement
- Considers uncertainties under a range of possible futures
- Considers all solutions for least cost/risk
- Motivates utility to choose least cost/risk solutions
- Enables consumers and third-party providers to propose grid solutions and participate in providing grid services

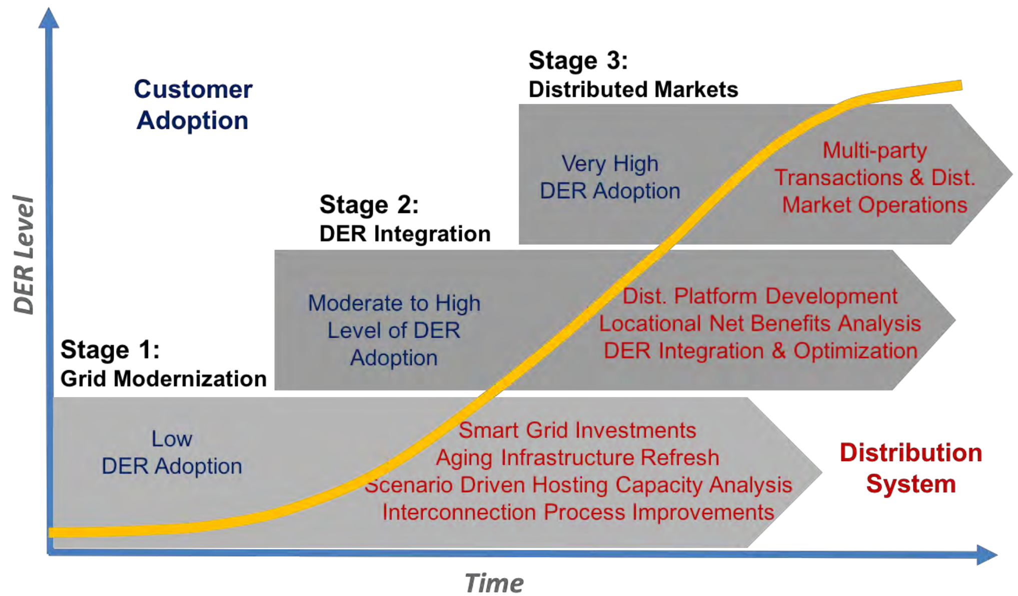
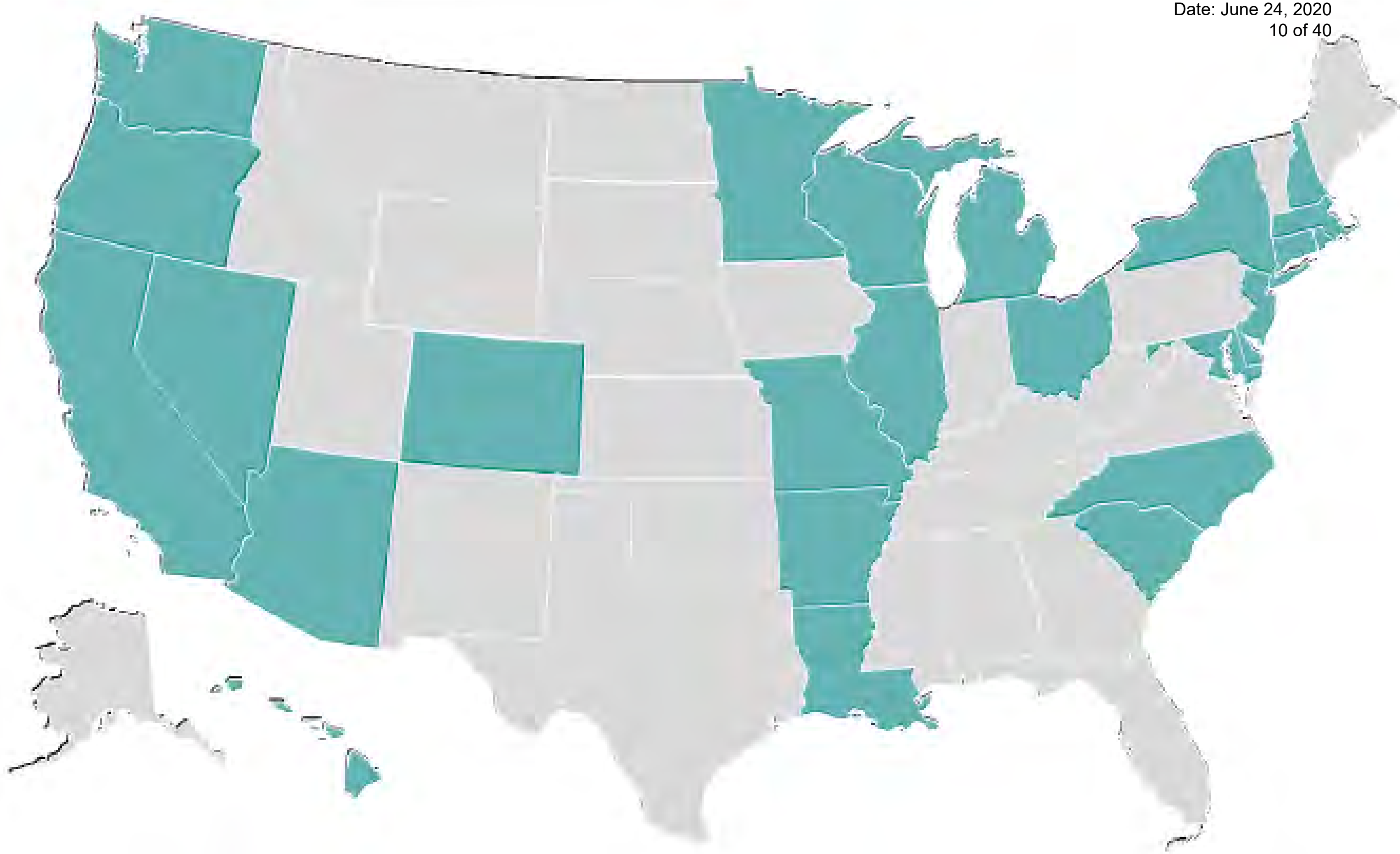


Figure from [De Martini and Kristov](), for Berkeley Lab

State Legislative and Regulatory Activities (I)



Distribution system planning activities in 25 states

Source: EPRI, *Modernizing Distribution Planning: Benchmarking Practices and Processes as They Evolve*. November 2019

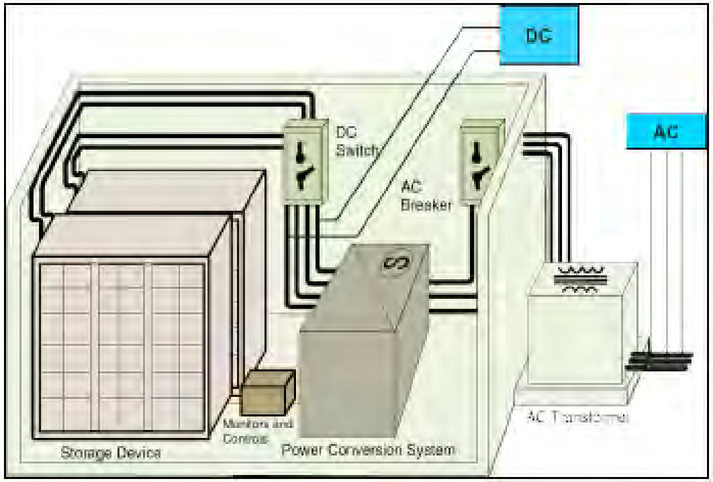
State Legislative and Regulatory Activities (2)

Common Components	Range of Requirements
Data Sharing and Transparency	Share a broad range of data including feeders, substations, operating voltages/ratings, load assumptions/forecasts, etc.
Hosting Capacity	Defining methods and tools, sharing maps, leveraging in planning and interconnection analysis. The granularity requested varies from requiring a node-level to feeder-level analysis. The frequency of updates ranges from monthly to annually.
Non-Wires Alternatives (NWAs)	Develop screening processes or criteria that can be used to identify when a grid need should be reviewed as a potential for NWAs. The consideration and assessment of NWAs in the investment plans varies by state – from being required to evaluate a NWA on every infrastructure investment to infrastructure projects of $1 million or greater.
Distribution System Plan Requirements	Provide annual documentation of the planning process and outline their distribution system investment plans to provide the scale of grid needs over a 5-year period. Some utilities are also required to define changes to the planning process in order to better incorporate DER.
Locational Value	Discussions are still in the early stages on this as is a longer-term component of the overall efforts. Some states like CA and NY are beginning to develop methods to assess locational value.

Source: EPRI, *Modernizing Distribution Planning: Benchmarking Practices and Processes as They Evolve*, November 2019

Some Considerations for Establishing a Regulatory Process for Distribution Planning

- Statutory requirements, regulatory precedents
- Priorities, phasing, related proceedings
- What's worked elsewhere, tailored to your state
- Recognize differences across utilities
- Regulatory clarity with built-in flexibility
- Quick wins, early benefits for consumers
- Long-term, cohesive view to achieve goals
- Pilots vs. full-scale approaches
  (including economy of scale, rate impacts)



Source: Sandia National Laboratories

Example State Objectives, Requirements and Planning Elements

Distribution Planning Objectives: Examples

- **Michigan**: Safety, reliability and resiliency, cost-effectiveness and affordability, and accessibility (order in U17990 and U-18014 dockets)
- **Nevada**: "reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits and any other savings the distributed resources provide to the electricity grid for this State or costs to customers of the electric utility or utilities." (SB 146)
- **Minnesota** Stat. § 216B.2425: "…enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies." Commission objectives (8/30/18 order in Docket 18-251):
  - Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies.
  - Enable greater customer engagement, empowerment, and options for energy services.
  - Move toward the creation of efficient, cost-effective, accessible grid platforms for new products and services, with opportunities for adoption of new distributed technologies.
  - Ensure optimized use of electricity grid assets and resources to minimize total system costs.

Example State Filing Requirements*

- Distribution system plans

  California, Delaware, Indiana, Hawaii, Maine, Maryland, Michigan, Minnesota, Nevada, New York, Rhode Island, Virginia

- Grid modernization plans

  California, Hawaii, Oregon, Massachusetts, Minnesota, Ohio

  - Utilities in several other states are filing grid modernization plans on their own (GA, NC, SC, TX).

- Requirements for hosting capacity analysis

  California, Minnesota, Nevada, New York

- Requirements to consider non-wires alternatives

  CA, CO, DC, HI, MD, ME, MN, NV, NY, RI

- Benefit-cost handbook or guidance

  Maryland, Nevada, New York, Rhode Island

*This list is growing and not all-inclusive.

Procedural Elements

- Frequency of filing
  - Typically annual or biennial
  - Every 3 years in MI (initially) and NV
  - *Considerations:* alignment with utility distribution capital planning, IRP filing cycle, workload, making/tracking progress on goals & objectives
- Planning horizon
  - 3 year action plan — NV (+ 6-year forecasts), DE (+ 10-year long-range plan)
  - 5 years – NY, CA (+ 10-year grid modernization vision), HI (+ long-term plan – to 2045), MI (+ 10-15 year outlooks), MN (+ 10-year Distribution System Modernization and Infrastructure Investment Plan)
  - 5-7 years - Indiana
  - *Considerations:* short- and long-term investments, coordination with IRP, distribution planning is granular (location-specific)

Procedural Elements (cont.)

- Stakeholder engagement requirements
  - *Before plan is filed:* Varies from one timely meeting required (MN) to significant upfront input through working groups (e.g., CA, DC, HI, MI, NY)
  - *After plan is filed:* Opportunity to file comments
- Confidentiality for security or trade secrets — for example:
  - Level of specificity for hosting capacity maps
  - Peak demand/capacity by feeder
  - Values for reliability metrics
  - Contractual cost terms
  - Bidder responses to RFPs
  - Proprietary model information

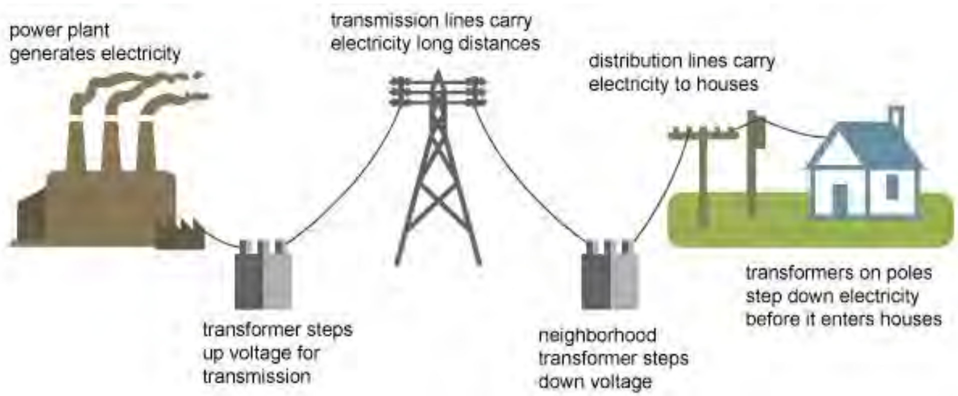


Figure: U.S. Energy Information Administration

Substantive Elements of Distribution Plans Considering DERs

- Baseline information on current state of distribution system
  - Such as system statistics, reliability performance, equipment condition, historical spending by category
- Description of planning process
  - Load forecast – projected peak demand for feeders and substations
  - Risk analysis – N-0 (normal overload) and N-1 (contingency risk of overload on adjacent feeder or transformer)
  - Mitigation plans – with risk thresholds
  - Budget for planned capacity projects
    - Asset health analysis and system reinforcements
    - Upgrades needed for capacity, reliability, power quality
    - New systems and technologies
    - Ranking criteria (e.g., safety, reliability, compliance, financial)
- Distribution operations — vegetation management and event management

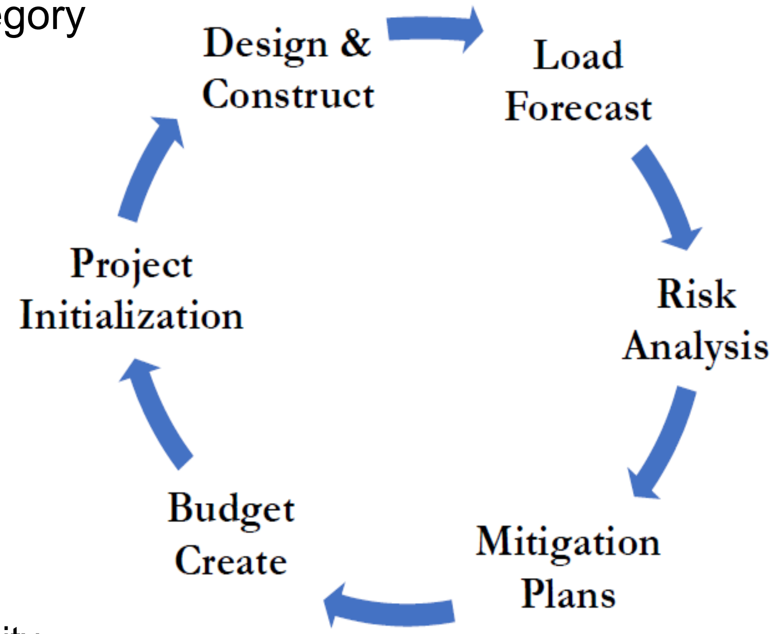


Figure: Xcel Energy, Integrated Distribution Plan, Nov. 1, 2019

Substantive Elements (cont.)

- DER forecast
  - Types and amounts
- NWA analysis
- Hosting capacity analysis*
  - Including maps
- Grid modernization strategy
  - May include request for certification for major investments
- Action plan
- Additional elements may include:
  - Long-term utility vision and objectives
  - Ways distribution planning is coordinated with integrated resource planning
  - Customer engagement strategy
  - Summary of stakeholder engagement
  - Proposals for pilots

*See Extra Slides for hosting capacity analysis use cases and drivers.

Example State-Specific Approaches

Michigan (1)

- PSC initially ordered utilities (in rate cases) to file 5-year distribution investment & maintenance plans "to increase visibility into the needs of maintaining the state's system and to obtain a more thorough understanding of anticipated needs, priorities, and spending."
  - Commission consolidated all 3 utility filings into Case No. U-20147 (April 2018)
- Following comments on draft plans, utilities filed final plans:
  - DTE Electric (2018), Consumers Energy (2018), Indiana Michigan (2019)
- PSC 2018 Staff Report - Distribution Planning Framework for an "open, transparent, and integrated electric distribution system planning process"
  - PSC Order on staff recommendations: "*framework … is to be used as a guide for the next iterations of distribution plans….*" "*Unconventional solutions, including targeted EE, DR, energy storage, and/or customer-owned generation, that could displace or defer investments in a cost-effective, reliable, and timely manner should be considered and evaluated.*"

Michigan PSC webpage on distribution system planning

Michigan (2)

- Sept. 2019 order in docket U-20147:
  - Utilities must file their next distribution investment and maintenance plans by June 30, 2021.
  - PSC staff will examine the value of resilience (and its role in cost-benefit methodologies for rate cases and alignment of distribution plans with IRPs) for the next phase of distribution plans. Staff will file a summary of the stakeholder process—including discussions on the value of resilience—for input into distribution plans by April 1, 2020.
  - Utilities will "continue to develop detailed distribution plans over a five-year period, but also include in the plan their vision and high-level investment strategies 10 and 15 years out. This approach is consistent with the planning horizons used in IRPs."
- Stakeholder workshops – June-November 2019
- MPSC Staff report on stakeholder workshops – April 1, 2020
- Commission is reviewing Staff's report and will provide guidance to the electric companies to prepare their next distribution plans.

Michigan (3)

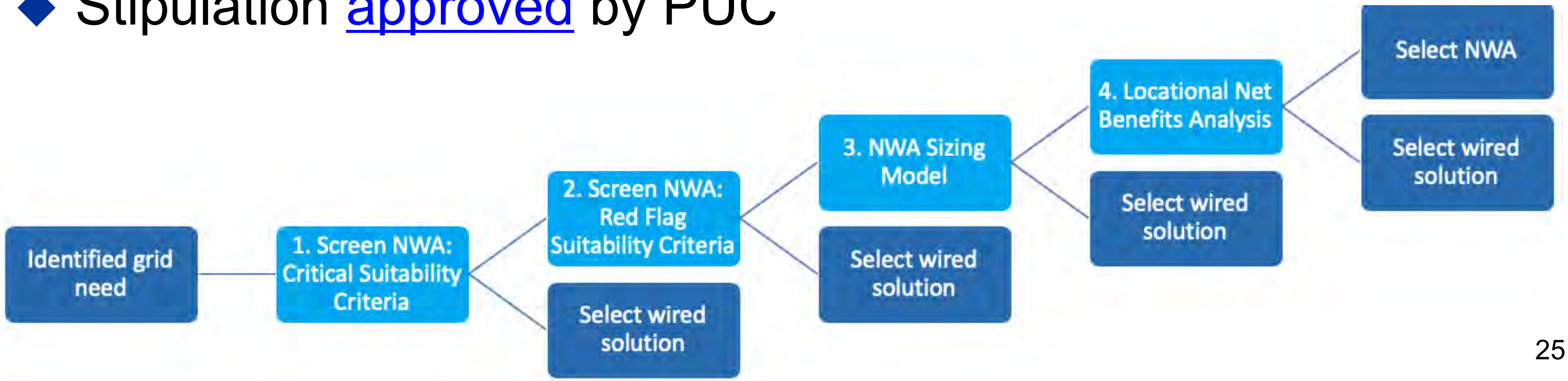
- *Michigan Statewide Energy Assessment* by PSC staff (September 2019) recommends utilities:
  - *"**better align electric distribution plans with integrated resource plans** to develop a cohesive, holistic plan and optimize investments considering cost, reliability, resiliency, and risk. As part of this effort, Staff, utilities, and other stakeholders should **identify refinements to IRP modeling parameters related to forecasts of distributed energy resources** (e.g., electric vehicles, on-site solar), **reliability needs with increased adoption of intermittent resources**, and the **value of fuel security and diversity of resources** in IRPs. A framework should also be developed to evaluate **non-wires alternatives** such as targeted energy waste reduction and demand response in IRPs and distribution plans."*
  - *"work with Staff and stakeholders to propose a **methodology to quantify the value of resilience, particularly related to DERs**. In addition, the value of resilience should be considered in future investment decisions related to energy infrastructure in future cases."*

Nevada (1)

- SB 146 (2017) requires utilities to file distributed resource plans (DRPs) to evaluate locational benefits and costs of distributed generation, energy efficiency, storage, electric vehicles and demand response technologies.
  - DRP identifies standard tariffs, contracts or other mechanisms for deploying cost-effective distributed resources that satisfy distribution planning objectives.
  - DRP is filed with IRP every 3 years and covers utility's 3-year IRP action plan
- PUC adopted temporary planning regulations in 2018 and permanent regulations in 2019 (D-17-08022)
  - 6-year forecast of net distribution system load (down to feeder level) and distributed resources
  - Hosting capacity analysis and public access to utility's online distribution maps/data
  - Grid Needs Assessment compares traditional and DER solutions for forecasted T&D system constraints
  - *"A utility may recover all costs it prudently and reasonably incurs in carrying out an approved DRP, in the appropriate separate rate proceeding."*

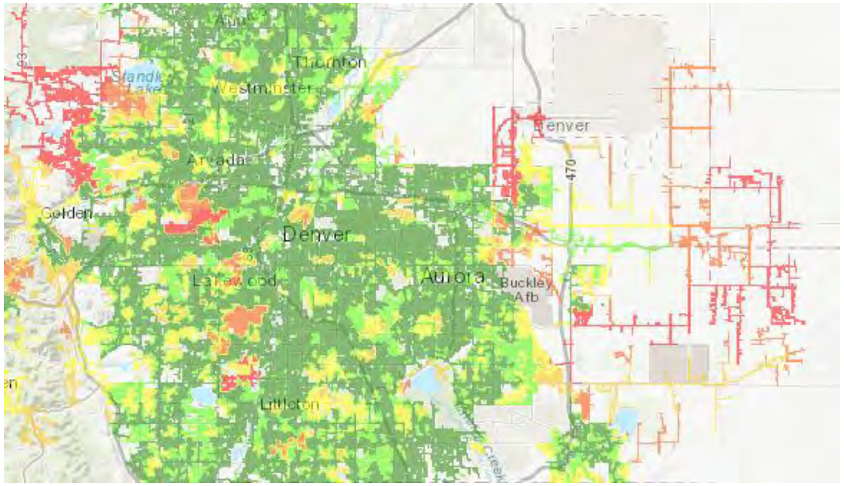
Nevada (2)

- NV Energy filed its 1st DRP in April 2019 (Docket D-19-04003)
  - Distribution system and distributed resource load forecast
  - Hosting capacity analysis
  - Grid Needs Assessment identifying distribution system constraints
  - NWA analysis
    - Utility's suitability/screening tool identified 10 distribution system projects and 107 transmission projects for NWA analysis
  - Locational net benefit analysis
    - Considered 8 costs and benefits; identified 3 projects with similar estimated costs for traditional solutions and NWA
- Stipulation approved by PUC



Colorado (1)

- SB 19-236 (2019) requires PUC to promulgate rules establishing filing of a distribution system plan (DSP), including:
  - Methodology for evaluating costs and net benefits of using DERs as NWAs
  - Threshold for size of new distribution projects
  - Requirements for DSP filings, including:
    - Consideration of NWAs for new developments (>10,000 residences)
    - Load forecasts from beneficial electrification programs
    - Forecast of DER growth
    - Planning process for cyber and physical security risks
    - Proposed cost recovery method
    - Anticipated new investments in distribution system expansion
    - Economic impacts of NWAs
    - Estimated year when peak demand growth merits analysis of new NWAs
  - Consider public interest and ratepayer benefits from NWAs
  - Benchmarks or accountability mechanisms

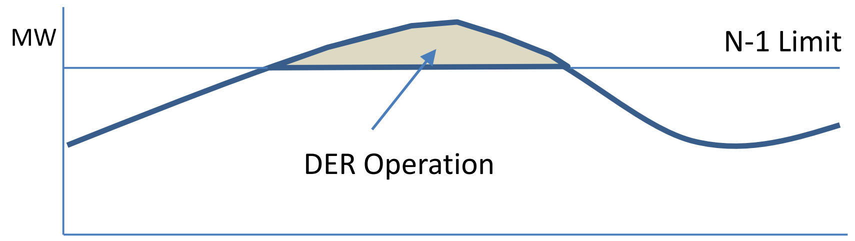


Xcel Energy hosting capacity map (Denver area)

Colorado (2)

- In Proceeding No. 17M-0694E, initiated through Decision No. C17-0878 (Oct. 26, 2017), the Commission examined implementation of an Integrated Distribution System Planning process and invited comments on:
  - "…initial regulatory steps that the Commission should take to ensure that investor-owned electric distribution systems have the capability to handle increased penetration of distributed generation, storage, and certain load building technologies such as electric vehicles."
  - Stakeholder engagement, including Distribution System Planning work group
- Pre-rulemaking proceeding underway (No. 19M-0670E)
  - Decision No. C19-0957 seeks comments and information on initial regulatory steps to meet requirements of SB 19-236
  - Series of informational workshops

Non-wires Alternatives: State Procurement Strategies



Source: E3

Considering Non-Wires Alternatives

- Non-wires alternatives (NWA) are options for meeting distribution (and transmission) system needs related to load growth, reliability and resilience.
  - Large DER (e.g., storage) or portfolio of DERs that can meet the specified need
- Objectives: Provide load relief, address over- or under-voltage, reduce interruptions, enhance resilience, or meet generation needs
- Potential to reduce utility costs
  - Defer or avoid infrastructure upgrades
  - Implement solutions *incrementally,* offering a flexible approach to uncertainty in load growth and potentially avoiding large upfront costs for load that may not show up

- Typically, utility issues a competitive solicitation for NWA for specific distribution system needs and compares these bids to planned traditional grid investments (e.g., distribution substation transformer) to determine the lowest reasonable cost solution, including implementation and operational risk assessment.

DER Procurement Strategies: New York (1)

- As part of their annual capital planning process, each utility must routinely identify candidate projects (load relief, reliability) for non-wires alternatives, post information to websites and issue RFPs.
- In 2017, utilities jointly provided suitability criteria for NWA projects and described how criteria will be applied in their capital plans.

Criteria	Potential Elements Addressed	
Project Type Suitability	Project types include Load Relief and Reliability*. Other categories currently have minimal suitability and will be reviewed as suitability changes due to State policy or technological changes.	
Timeline Suitability	**Large Project**	36 to 60 months
	Small Project	18 to 24 months
Cost Suitability	**Large Project**	≥ $1M
	Small Project	≥ $300k

DER procurement strategies: New York (3)

- May 2017 supplemental filing describes procurement process to award contracts; also see Joint Utilities NWA process
- RFP response requirements include:
  - Proposed solution description
  - Project schedule and acquisition plan
  - Detailed costs associated with proposed solution
  - Risks, challenges and community impacts
  - Professional background and experience
- All NWA opportunities on REV Connect website
  - Example NWA: Rochester Gas & Electric plans to use targeted efficiency near Station 51 to reduce peak demand that would otherwise be met with traditional upgrades

DER Procurement Strategies: New York (2)

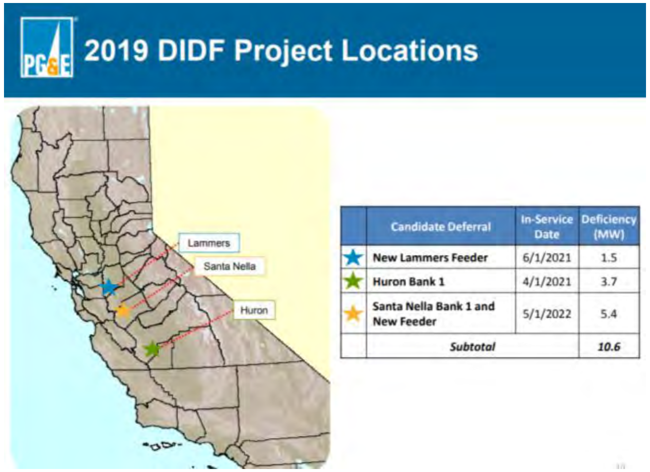
Projects, Needs and Default Solutions:
Example Consolidated Edison RFPs for Non-Wires Alternatives

Project (RFP year)	Need	Default Solution
Hudson Network (2017)	Amount: 7.1 MW Location: West 50th St. Substation Overload period: 1-8 pm (5 pm peak) When: 2021 (summer)	Feeder upgrades to reduce potential overloads
Columbus Circle Network (2017)	Amount: 4 MW Location: West 42nd St. No. 2 Substation Overload period: 2–7 pm (6 pm peak) When: 2021 (summer)	Feeder upgrades to reduce potential overloads
West 42nd Street Load Transfer Project (2017)	Amount: 42 MW (total, varies by year) Location: W. 42nd St. No. 1 Substation Overload period: 9 am–7 pm (2–3 pm peak) When: 2021–2027 (starting May 2021)	Transfer 55 MW of load from W. 42nd St. No. 1 Substation to Astor Substation before summer 2021

Sources: Con Edison 2017a, Con Edison 2017b, and Con Edison 2017c

DER procurement strategies: California

- Distribution Investment Deferral Framework decision (Feb. 2018) created annual process for consideration of DERs
  - *"The central objective…is to identify and capture opportunities for DERs to cost-effectively defer or avoid traditional IOU investments that are planned to mitigate forecasted deficiencies of the distribution system."*
  - Utilities file two reports annually:
    1) Grid Needs Assessment (example GNA) is main driver for Distribution Resources Plan
    2) Distribution Deferral Opportunity Report (DDOR)



	Candidate Deferral	In-Service Date	Deficiency (MW)
★	New Lammers Feeder	6/1/2021	1.5
★	Huron Bank 1	4/1/2021	3.7
★	Santa Nella Bank 1 and New Feeder	5/1/2022	5.4
	Subtotal		*10.6*

Source: PG&E presentation on 2019 RFO for local distribution capacity relief in 3 areas

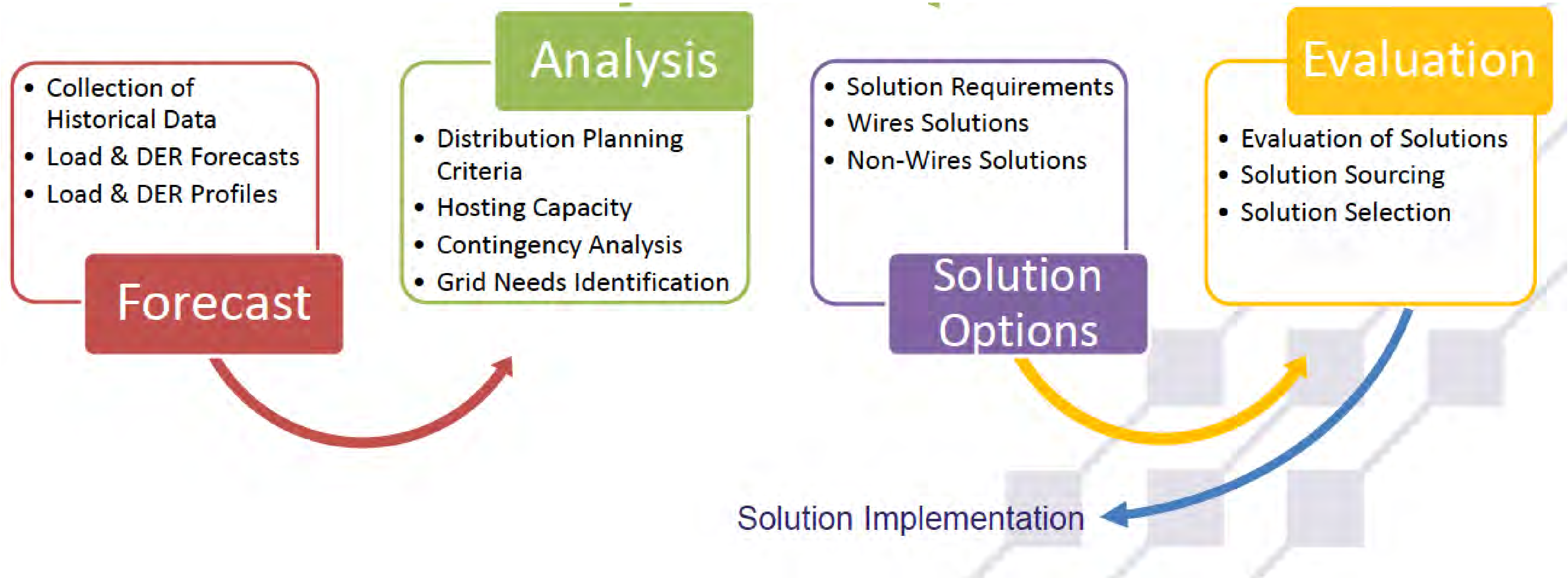
  - Recommend deferral projects for competitive annual solicitations
    - Examples: SCE, PG&E, SDG&E
  - May 2019 update modifies requirements
    - GNA and DDOR in consolidated filing with specific $/MWh and locational net benefit analysis values for prioritizing projects
    - Additional requirements for GNA narrative and datasets
    - Additional project-specific data required for planned investments and candidate deferral project shortlist

Hawaii

- Order No. 34281 provided guidance for a holistic, scenario-based grid modernization strategy to inform review of discrete projects submitted by utility
- Hawaiian Electric Companies' (HECO) Integrated Grid Planning incorporates procurement *into planning itself*, not after planning
- Integrated Grid Planning process (Order 35569)
  1. Develop forecasts and assumptions that will drive planning
  2. Collectively identify needs for G,T & D
  3. Identify solutions that can be achieved through procurement, pricing and program options
  4. Evaluate and optimize resource and T&D solutions, submit 5-year plan to PUC with proposed investments, pricing and programs

- Allows a variety of distributed and grid scale resources to provide power generation and ancillary services
- Stakeholder council, technical advisory panel, ad-hoc working groups

Hawaii's Advanced Distribution Planning Process



Source: HECO presentation to Puerto Rico Energy Bureau, Jan. 10, 2020

Resources for More Information

U.S. Department of Energy's (DOE) Modern Distribution Grid guides

Schwartz, Lisa. 2020. "PUC Distribution Planning Practices." Distribution Systems and Planning Training for Southeast Region. March 12, 2020. Lawrence Berkeley National Laboratory

Alan Cooke, Juliet Homer, Lisa Schwartz, *Distribution System Planning – State Examples by Topic*, Pacific Northwest National Laboratory and Berkeley Lab, 2018

Juliet Homer, Alan Cooke, Lisa Schwartz, Greg Leventis, Francisco Flores-Espino and Michael Coddington, *State Engagement in Electric Distribution Planning*, Pacific Northwest National Laboratory, Berkeley Lab and National Renewable Energy Laboratory, 2017

Berkeley Lab's Future Electric Utility Regulation reports

Berkeley Lab's research on time- and locational-sensitive value of DERs

Summary of Electric Distribution System Analyses with a Focus on DERs, by Y. Tang, J.S. Homer, T.E. McDermott, M. Coddington, B. Sigrin, B. Mather, Pacific Northwest National Laboratory and National Renewable Energy Laboratory, 2017

J.S. Homer, Y. Tang, J.D. Taft, D. Lew, D. Narang, M. Coddington, M. Ingram, A. Hoke. *Electric Distribution System Planning with DERs — Tools and Methods* (forthcoming)

T. Woolf, B. Havumaki, D. Bhandari, M. Whited and L. Schwartz. *Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges and Considerations*. Lawrence Berkeley National Laboratory (forthcoming)

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Extra Slides

State drivers for hosting capacity analysis

	Hosting Capacity
Hawaii *Key Driver: Legislative Mandates & regulatory requirements from Commission*	• Locational Value Maps available online • Integrated Interconnection Queue for all areas, including those currently exceeding hosting capacity • Customers can check the status of their interconnection application online
California *Key Driver: Distribution Resource Planning Proceedings*	• Goal is to streamline the interconnection review process. • Replaces interconnection screens in some instances • Interconnection Capacity Analysis (ICA) 2.0 maps expand analysis to include output values such as alternate circuit configurations and storage ICA with high accuracy and monthly updates
New York *Key Driver: Reforming the Energy Vision*	• Hosting Capacity maps are provided to guide solar PV developers to locations with lower expected interconnection costs • Goal is to eventually build to an integrated value assessment tool
Minnesota *Key Driver: Regulatory & legislative mandates for renewable generation, emission reduction and fossil fuel reduction*	• Focus on planning and incorporating lessons learned from other jurisdictions • Xcel published visual hosting capacity maps and allow for formal request for interconnection on-site and for pre-application data request

Source: ICF, for DOE

Use Cases for Hosting Capacity

Use Case	Description	CA IOUs	NY IOUs	HI	APS	Xcel	Pepco
Utility Interconnection Analysis	HCA as a utility tool for evaluating interconnection applications (SIS), (dependency: interconnection)				●		
Distribution Planning Tool	HCA as a tool to enable greater DER integration by identifying potential future constraints and proactive upgrades (dependency: locational value, forecasting)	●		●			
Interconnection Technical Screen	Use of HCA as a means to automate technical screens as part of the state interconnection process (dependency: interconnection)	●		●			●
Development Guide	HCA to identify areas with potentially lower interconnection costs	●	●	●		●	●
Dynamic Hosting Capacity	Identify impacts to the system from DER dispatch in real time based on the as-switched system (dependency: locational value)						

Source: ICF, for DOE

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	)))))	Case No. U-20697

EXHIBITS OF

DR. GABRIEL CHAN

ON BEHALF OF

THE ECOLOGY CENTER
THE ENVIRONMENTAL LAW & POLICY CENTER
THE GREAT LAKES RENEWABLE ENERGY ASSOCIATION
THE SOLAR ENERGY INDUSTRIES ASSOCIATION
AND VOTE SOLAR

June 24, 2020

MN Distributed Solar Value Methodology

March 4, 2014

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Presentation Outline

Overview

- MN DG Timeline
- VOS Features
- VOS Statute; Commerce Approach
- Key Points; Key Benefits; Methodology Highlights

Methodology

- Objectives; Components; Transparency Elements
- Load Analysis Period; PV Energy Production; Load Match Factors
- Loss Savings Analysis
- Avoided Fuel Cost; Avoided Generation Capacity Cost
- Avoided Environmental Cost; Social Cost of Carbon
- Discount and Escalation Factors

Sample Calculation

- Inflation Adjusted Rate

Timeline - Minnesota DG & VOS

1981

Cogeneration & Small Power Production (MN Statute 216B.164)
- Requires Net Metering for qualifying facilities < 40 kW
- Required purchase of all energy& capacity at Avoided cost for all facilities > 40 kW

1983

Cogeneration & Small Power Production (MN Rules Chapter 7835)
- Requires cogeneration & small power production tariff; requires reporting

2001

Interconnection of On-Site DG (MN Statute 216B.1611)
- Established the terms and conditions that govern the interconnection and parallel operation of on-site distribution generation
- Required DG tariffs & annual reporting

2003 / ongoing

IEEE 1547 Technical specifications and requirements for interconnecting distributed resources

2004

Commission Order Establishing Standards for Interconnection & Operation of DG (MN PUC Docket E-999 / CI-01-1023)

2005

Opportunities for Distributed Generation (MN Statute 216B.2426)
Commission shall ensure that opportunities for DG are considered in Resource Planning (216B.2422), State Transmission Plan (216B.2425), Certificate of Need for Large Energy Facility (216B.243)

2006

FERC Standard Interconnection Agreements & Procedures for Small Generators (Docket RM-12-002)

2009

Distributed Energy Resources (MN Statute 216B.2411)
- MN utilities may spend 5% of approved energy conservation spending requirement on DG
- May request permission for up to 10% for qualifying solar energy projects (<100 kW)

2011 – 2013

MN 2013 Legislature
- Established a Solar Energy Standard
- Updated the state's 30 year old net metering law
- Established Production Based and Made in MN Incentives
- Provided opportunities for Community Solar Gardens
- Established a process for a Value of Solar Tariff

MN DER engaged stakeholders to review and assess distributed resources
- Workshops on DG technologies, contractual issues, net metering, interconnection, baseline & benchmarks, impacts & fees, value of solar

2013 – 2014

MN Value of Solar (VOS) Methodology Development

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Features of Value of Solar (VOS)

VOS is the value of distributed solar to the utility, its customers, and society

The customer remains connected to the grid as a full customer of the utility and a new billing calculation method addresses the problems with the current net metering

- VOS eliminates cross-subsidization concerns with net metering

VOS is expressed in a present value, $ per kWh, for a 25-year levelized stream

- Similar to a long term contract rate

VOS will encourage energy efficiency

- Under VOS, the solar customer is encouraged to use less energy during peak periods

VOS is

- Fair to the utility and non-solar customers
- Provides fair compensation to the solar customer
- Decouples compensation from incentives
- Aligns public policy goals (decouples compensation from consumption)
- Intuitively and analytically sound and administratively simple

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Subdivision 10 Alternative tariff – Sec. 10. 216B.164

(a) **A public utility may apply** for commission approval for an alternative tariff that compensates customers through a bill credit mechanism for the **value to the utility, its customers, and society** for operating distributed solar photovoltaic resources interconnected to the utility system and operated by customers primarily for meeting their own energy needs.

(b) **If approved, the alternative tariff shall apply to customers' interconnections occurring after the date of approval.** The alternative tariff is **in lieu of** the applicable rate under subdivisions 3 and 3a.

(c) The commission shall after notice and opportunity for public comment approve the alternative tariff provided the utility has demonstrated **the alternative tariff:**

(1) **appropriately applies the methodology established by the department and approved by the commission under this subdivision;**

(2) includes a mechanism to allow recovery of the cost to serve customers receiving the alternative tariff rate;

(3) **charges the customer for all electricity consumed by the customer at the applicable rate schedule for sales to that class of customer;**

(4) **credits the customer for all electricity generated by the solar photovoltaic device at the distributed solar value rate established under this subdivision;**

(5) applies the charges and credits in clauses (3) and (4) to a monthly bill that includes a provision so that the unused portion of the credit in any month or billing period shall be carried forward and credited against all charges. In the event that the customer has a positive balance after the 12-month cycle ending on the last day in February, that balance will be eliminated and the credit cycle will restart the following billing period beginning on March 1;

(6) complies with the size limits specified in subdivision 3a;

(7) complies with the interconnection requirements under section 216B.1611; and

(8) complies with the standby charge requirements in subdivision 3a, paragraph (b).

(d) A utility must provide to the customer the meter and any other equipment needed to provide service under the alternative tariff.

(Emphasis Added)

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Subdivision 10 Alternative tariff – Sec. 10. 216B.164

(e) **The department must establish the distributed solar value methodology in paragraph (c), clause (1), no later than January 31, 2014. The department must submit the methodology to the commission for approval. The commission must approve, modify with the consent of the department, or disapprove the methodology within 60 days of its submission. When developing the distributed solar value methodology, the department shall consult stakeholders with experience and expertise in power systems, solar energy, and electric utility ratemaking regarding the proposed methodology, underlying assumptions, and preliminary data.**

(f) **The distributed solar value methodology established by the department must, at a minimum, account for the value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value. The department may, based on known and measurable evidence of the cost or benefit of solar operation to the utility, incorporate other values into the methodology, including credit for locally manufactured or assembled energy systems, systems installed at high-value locations on the distribution grid, or other factors.**

(g) **The credit for distributed solar value applied to alternative tariffs approved under this section shall represent the present value of the future revenue streams of the value components identified in paragraph (f).**

(h) The utility shall recalculate the alternative tariff on an annual cycle, and shall file the recalculated alternative tariff with the commission for approval.

(i) **Renewable energy credits for solar energy credited under this subdivision belong to the electric utility providing the credit.**

(j) The commission may not authorize a utility to charge an alternative tariff rate that is lower than the utility's applicable retail rate until three years after the commission approves an alternative tariff for the utility.

(k) A utility must enter into a contract with an owner of a solar photovoltaic device receiving an alternative tariff rate under this section that has a term of at least 20 years, unless a shorter term is agreed to by the parties.

(l) An owner of a solar photovoltaic device receiving an alternative tariff rate under this section must be paid the same rate per kilowatt-hour generated each year for the term of the contract.

(Emphasis Added)

Commerce Approach

The MN VOS Methodology is based on:

- The enabling statute;
- Commerce analysis;
- Extensive stakeholder input.

The MN VOS Methodology incorporates significant national experience and expertise including:

- Clean Power Research – Provided technical and analytical support for development of the MN Methodology; Performed or supported a dozen Value of Solar studies over the last 15 years
- Rocky Mountain Institute – Meta-analysis of many recent Solar PV Benefit and Cost Studies
- Karl Rabago – Austin Energy VOST experience

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Key Points

The VOS Methodology accounts for the *value to the utility, its customers, and society* for the required components (energy and its delivery, generation capacity, transmission and distribution losses, and environmental value)

- The VOS Methodology requires a broader assessment than current resource planning and thus requires new analytical approaches;
- Any components other than those required must be based on known and measurable evidence of the cost or benefit of solar operation to the utility.

VOS is *not* an incentive for distributed PV, nor is it intended to eliminate or prevent future incentive programs.

- Compensation (credit) levels and incentive levels should be separated to communicate clear signals to the market and to facilitate ongoing administration;
- VOS is expected to reduce the need for incentives over time by correctly compensating (through a credit) for value provided.

VOS is *not* 'buy-all-sell-all'

- Under VOS, the customer is credited through a bill mechanism;
- A VOS tariff that appropriately applies the methodology established by the Department will not result in any sale of distributed solar energy by the customer. The customer purchases all of the electricity consumed from the utility under their existing retail tariff and is *credited* for all of the distributed PV energy produced at the VOS tariff rate

VOS is *not* in conflict with the Public Utility Regulatory Policies Act (PURPA)

- A VOS tariff will not replace or remove a customer's ability to serve onsite load if desired.

Key Benefits

VOS eliminates cross-subsidization concerns

- The solar customer purchases all of the electricity consumed under their existing retail tariff rate – ensures that utility infrastructure costs will be recovered by the utilities as designed in the retail tariff;
- The solar customer is *credited* for all of the distributed PV energy produced at the VOS tariff rate.

VOS provides an incentive for efficiency

- Traditional net metering couples solar energy value to the customer's energy consumption and thus can discourage energy efficiency and can encourage on peak consumption;
- Under VOS, the solar customer is encouraged to use less energy during peak periods.

VOS provides a rigorous analytical foundation for valuing distributed solar energy that can be updated and adjusted over time

- VOS Methodology is clear and specific;
- Annual adjustments to the valuation (for each new annual group of VOS tariff customers) prevents over- or under- payment as utility costs change;
- The Methodology can be updated as needed to incorporate the best available practices.

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Methodology Highlights

Component values

- Energy – The value of energy PV displaces, energy produced by the marginal unit in real time, including the cost of long-term price risk;
- Capacity – PV's hourly kW contribution to grid reliability multiplied by the capital cost of installing a new marginal generation facility (natural gas turbines) over the full 25 year life of the PV resource;
- Environmental – Based on Minnesota (non-CO_2) and EPA (CO_2) externality values;
- Transmission and Distribution – Represents deferred T&D capital investments;
- Loss savings – PV generation at or near the point of energy consumption saves on T&D losses associated with the remotely generated energy it displaces.

Economic Analysis Period

- The analysis period and the assumed contract period are 25 years to align with the expected lifespan of PV panels.

VOS Tariff Updated Annually

- Updated annually for each new annual group of VOS tariff customers.

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Methodology Objectives

1. Accurately account for all relevant value streams;
2. Simplify input data set and methodology (where possible & warranted);
3. Provide transparency;
4. Facilitate modification, if necessary, in future years.

Components

Value Component	Basis	Legislative Guidance	Notes
Avoided Fuel Cost	Energy market costs (portion attributed to fuel)	Required (energy)	Includes cost of long-term price risk
Avoided Plant O&M Cost	Energy market costs (portion attributed to O&M)	Required (energy)	
Avoided Generation Capacity Cost	Capital cost of generation to meet peak load	Required (capacity)	
Avoided Reserve Capacity Cost	Capital cost of generation to meet planning margins and ensure reliability	Required (capacity)	
Avoided Transmission Capacity Cost	Capital cost of transmission	Required (transmission capacity)	
Avoided Distribution Capacity Cost	Capital cost of distribution	Required (delivery)	
Avoided Environmental Cost	Externality costs	Required (environmental)	
Voltage Control	Cost to regulate distribution (future inverter designs)		Future (TBD)
Integration Cost	Added cost to regulate system frequency with variable solar		Future (TBD)

Transparency Elements

The Methodology incorporates two tables that are to be included in a utility's application to the Commission for use of a VOS tariff:

1. **VOS Data Table**
   - Utility specific input assumptions
2. **VOS Calculation Table**
   - List of value components and their gross values, their load match factors, their loss savings factors, and the computation of the total levelized value

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Example VOS Data Table
- utility-specific input data

	Input Data	Units
Economic Factors		
Start Year for VOS applicability	2014	
Discount rate (WACC)	8.00%	per year
Load Match Analysis (see calculation method)		
ELCC (no loss)	40%	% of rating
PLR (no loss)	30%	% of rating
Loss Savings - Energy	8%	% of PV output
Loss Savings - PLR	5%	% of PV output
Loss Savings - ELCC	9%	% of PV output
PV Energy (see calculation method)		
First year annual energy	1800	kWh per kW-AC
Transmission (see calculation method)		
Capacity-related transmission capital cost	$33	$ per kW-yr

	Input Data	Units
Power Generation		
Peaking CT, simple cycle		
Installed cost	900	$/kW
Heat rate	9,500	BTU/kWh
Intermediate peaking CCGT		
Installed cost	1,200	$/kW
Heat rate	6,500	BTU/kWh
Other		
Solar-weighted heat rate (see calc. method)	8000	BTU per kWh
Fuel Price Overhead	$0.50	$ per MMBtu
Generation life	50	years
Heat rate degradation	0.100%	per year
O&M cost (first Year) - Fixed	$5.00	per kW-yr
O&M cost (first Year) - Variable	$0.0010	$ per kWh
O&M cost escalation rate	2.00%	per year
Reserve planning margin	15%	
Distribution		
Capacity-related distribution capital cost	$200	$ per kW
Distribution capital cost escalation	2.00%	per year
Peak load	5000	MW
Peak load growth rate	1.00%	per year

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VOS Calculation Table

25 Year Levelized Value	Gross Value ($/kWh)	×	Load Match Factor (%)	× (1 +	Loss Savings Factor (%)	)	=	Distributed PV Value ($/kWh)
Avoided Fuel Cost	GV1				LSF-Energy			V1
Avoided Plant O&M - Fixed	GV2				LSF-Energy			V2
Avoided Plant O&M - Variable	GV3				LSF-Energy			V3
Avoided Gen Capacity Cost	GV4		ELCC		LSF-ELCC			V4
Avoided Reserve Capacity Cost	GV5		ELCC		LSF-ELCC			V5
Avoided Trans. Capacity Cost	GV6		ELCC		LSF-ELCC			V6
Avoided Dist. Capacity Cost	GV7		PLR		LSF-PLR			V7
Avoided Environmental Cost	GV8				LSF-Energy			V8
Avoided Voltage Control Cost								
Solar Integration Cost								
								Value of Solar

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Load Analysis Period

The Methodology requires that a number of technical parameters be calculated over at least one full year in order to account for day-to-day variations and seasonal effects.

Three types of time series data are required to perform the technical analysis:

- Hourly utility generation
- Hourly distribution load
- Hourly PV fleet production

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PV Energy Production

- **PV System Rating Convention**
  - Methodology uses a rating convention for PV systems that calculates the AC output from the PV system, taking into account losses internal to the PV system.

- **PV Fleet Production**

  Hourly PV Fleet Production can be obtained using any one of three options:

  1. Utility Fleet Metered Production
  2. Utility Fleet Simulated Production
  3. Expected Fleet Simulated Production

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Load Match Factors

Capacity-related benefits are time-dependent, so it is necessary to evaluate the effectiveness of PV in supporting loads during the critical peak hours

Two different measures of effective capacity are used:

- **Effective Load Carrying Capability (ELCC)**
  - ELCC is the effective capacity of distributed PV that can be applied to the avoided generation capacity related costs; it is a measure of the distributed PV fleets' contribution to system reliability;
  - The MISO Business Practices Manual (BPM) approach specified in the Methodology is an ELCC approximation that focuses on the PV fleet production during system peak load hours.
- **Peak Load Reduction (PLR)**
  - PLR the effective capacity of distributed PV that can be applied to the avoided distribution capacity costs; it is a measure of the PV fleet to reduce the peak distribution load over the year;
  - The PLR is defined as the maximum hourly distribution load over the year (without the Marginal PV Resource) minus the maximum distribution load hourly over the year (with the Marginal PV Resource).

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Loss Savings

The required Loss Savings Factors (Avoided Annual Energy, ELCC, PLR) are calculated as follows:

- Avoided losses are calculated hourly over the year
- Avoided losses in the transmission system and in the distribution systems are evaluated separately
- Avoided losses are calculated on a marginal basis (hourly difference in losses between the case without the PV resource and the case with the PV resource)
- Distribution losses are based on the power entering the distribution system, after transmission losses
- Avoided transmission losses take into account not only the marginal PV generation, but also the avoided marginal distribution losses
- Calculation of avoided hourly losses will account for the non-linear relationship between losses and load

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Avoided Fuel Cost

Based on the value of long-term, risk-free fuel supply

- PV displaces energy generated from the marginal unit, so it avoids the cost of fuel associated with this generation.
- To correctly account for the displaced energy generated from the marginal unit, the methodology includes calculation of a utility-specific Solar Weighted Heat Rate.
- The PV system has a service life of 25 years, so the uncertainty in fuel price fluctuations is also eliminated over this period. For this reason, the avoided fuel cost must take into account the fuel as if it were purchased under a guaranteed, long term contract – the Methodology provides for three options: Futures Market, Long Term Price Quotation, or Utility Guaranteed Price.
    - Fuel Price Escalation Factor: 30-day averages are used for the NYMEX Natural Gas Futures contract prices for years 1 through 12; For years beyond year 12, the general escalation rate is used as the guaranteed fuel price escalation;

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Avoided Generation Capacity Cost

Based on a weighting of capital cost of combustion turbines (CTs) and combined cycle gas turbines (CCGTs) according to the marginal solar heat rate, which is multiplied by (i.e. reduced by) the Load Match Factor (ELCC) in recognition that capacity related benefits are time-dependent.

- The methodology represents the avoided cost of capacity over the full 25 year life of the PV resource, not only the near term avoided capital costs.
- Distributed solar PV is a modular resource that is developed and installed in smaller increments than larger additions of typical utility-sized generation.
- Reliability contributions of new generation are recognized each year in the annual planning reserve margin calculation in MISO's annual Loss of Load Expectation (LOLE) study.

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Avoided Environmental Cost

Environmental costs are included as a required component and are based on Minnesota and EPA externality costs

- As with other components, calculation of the avoided environmental costs is based on the energy resource on the margin that the distributed solar is displacing (e.g. natural gas).
- The avoided environmental cost approach requires calculating the avoided emissions and applying the environmental cost factors to calculate the avoided environmental costs in economic terms (dollars).
- CO_2 costs are calculated using the EPA Social Cost of Carbon values which account for marginal damage costs
- All pollutants other than CO_2 are calculated using the Minnesota externality costs

Social Cost of Carbon

The statute requires that the VOS tariff "compensates customers through a bill credit mechanism for the value *to the utility, its customers, and society*" (emphasis added). The avoided environmental costs of pollution include damage costs in addition to the utility's avoided pollution mitigation or compliance cost.

- The Social Cost of Carbon was developed through a number of federal agency actions.
- The EPA describes the Social Cost of Carbon as:
  - A comprehensive estimate of climate change damages and includes, among other things, changes in net agricultural productivity, human health, and property damages from increased flood risk.
  - An estimate of the economic damages associated with a small increase in carbon dioxide (CO_2) emissions, conventionally one metric ton, in a given year.
- The VOS Methodology uses the EPA central discount value of 3 percent.

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Discount and Escalation Factors

The value of solar methodology is designed to account for the value of solar energy to the utility, its customers, and society using a present value analysis.

- The statute states that the tariff credit shall represent the present value of the future revenue streams of the value components. This requires accounting for inflation of avoided costs and discounting future costs.
- Three discount rates are used:
  - The utility's rate of return requirements (weighted average cost of capital),
  - The risk-free discount rate to value an investment with no uncertainty, and
  - The environmental discount rate to assess future environmental impacts today
- Inflation is an important factor in all utility rates.
  - The methodology calls for the conversion of the 25-year levelized value to an equivalent inflation-adjusted credit rate.

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Example Results

25 Year Levelized Value	Gross Starting Value ($/kWh)	×	Load Match Factor (%)	× (1 +	Loss Savings Factor (%)	) =	Distributed PV Value ($/kWh)
Avoided Fuel Cost	$0.061				8%		$0.066
Avoided Plant O&M - Fixed	$0.003		40%		9%		$0.001
Avoided Plant O&M - Variable	$0.001				8%		$0.001
Avoided Gen Capacity Cost	$0.048		40%		9%		$0.021
Avoided Reserve Capacity Cost	$0.007		40%		9%		$0.003
Avoided Trans. Capacity Cost	$0.018		40%		9%		$0.008
Avoided Dist. Capacity Cost	$0.008		30%		5%		$0.003
Avoided Environmental Cost	$0.029				8%		$0.031
Avoided Voltage Control Cost							
Solar Integration Cost							
							$0.135

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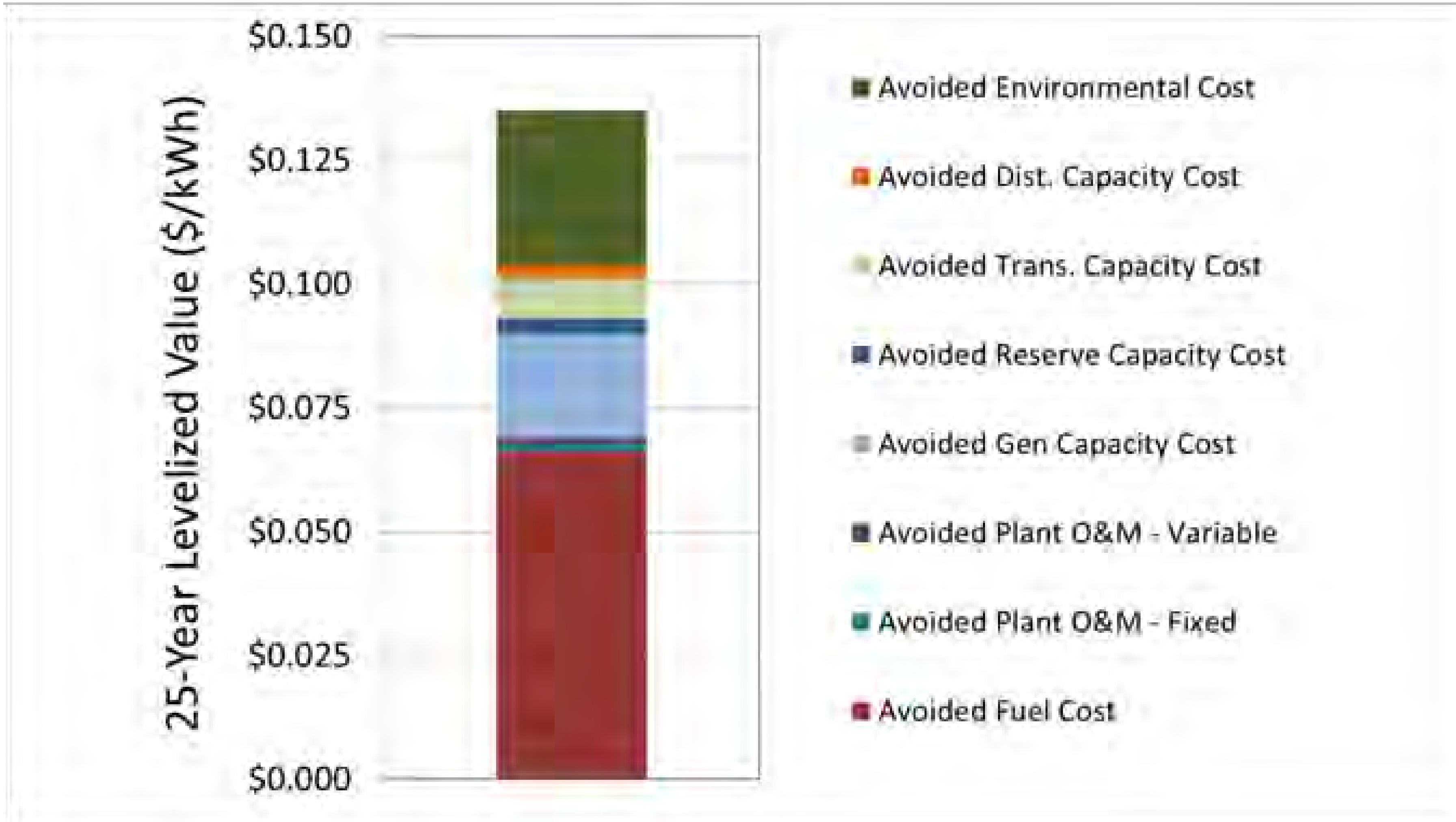
Example Results



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Inflation Adjusted Rate

The methodology calls for the conversion of the 25-year levelized value to an *equivalent* inflation-adjusted credit rate.

- Ensures that the credit's value will remain proportional to future costs of other electricity generation methods, while also meeting the statute's requirement that solar generators receiving VOS credits be paid the same rate during the contract's life in real economic value terms;
- Whether the rate is levelized or inflation-adjusted has implications for PV project financing;
- The most appropriate approach to ensure that the value of solar resources are maintained throughout their lives is to use a rate that is adjusted over time based on an inflation factor.

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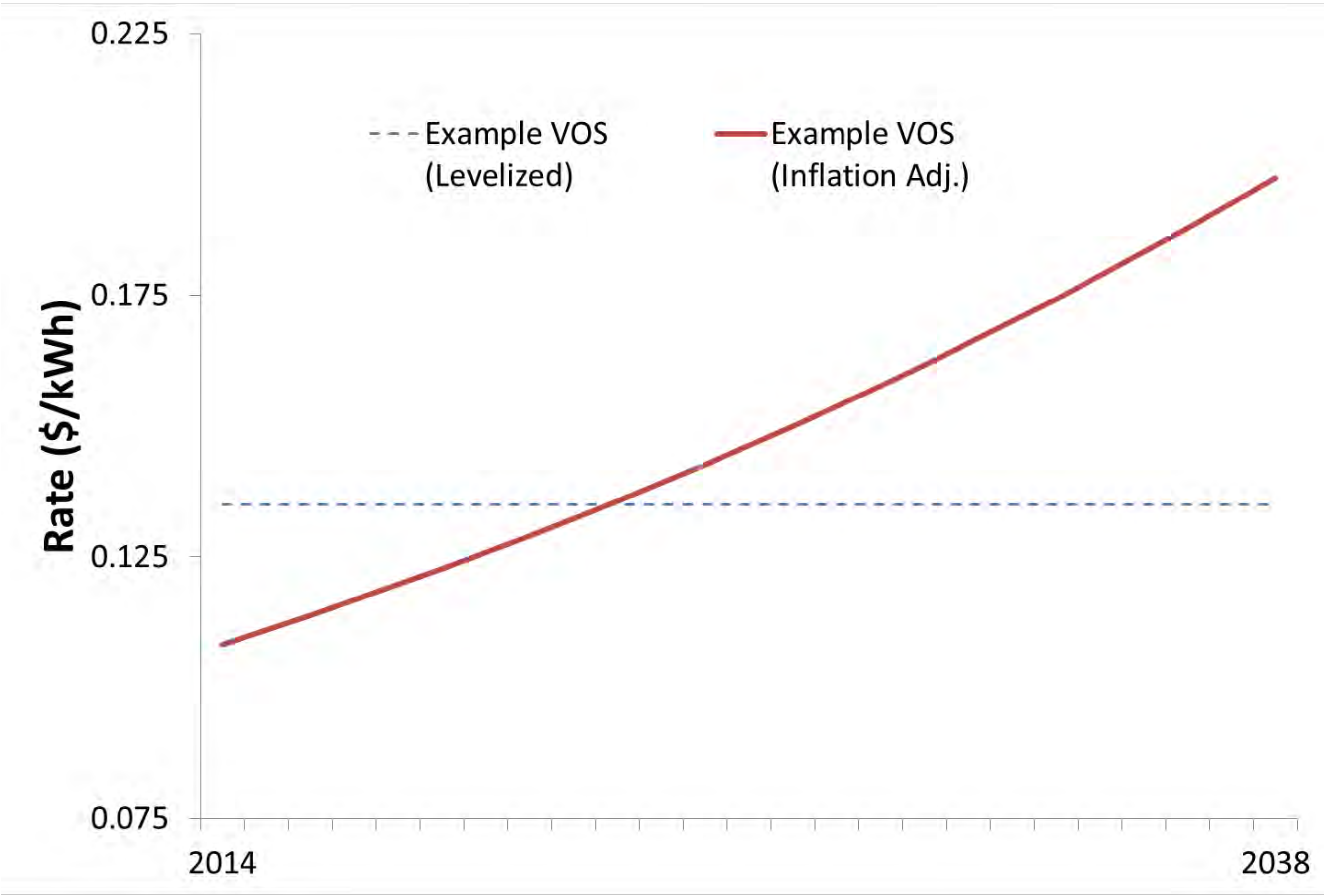
Example Results



Minnesota Value of Solar: Methodology

Minnesota Department of Commerce,

Division of Energy Resources

APRIL 1, 2014*

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Legal Notice from Clean Power Research

Executive Summary

Minnesota passed legislation[1] in 2013 that allows Investor-Owned Utilities (IOUs) to apply to the Public Utility Commission (PUC) for a Value of Solar (VOS) tariff as an alternative to net metering, and as a rate identified for community solar gardens. The Department of Commerce (Commerce) was assigned the responsibility of developing and submitting a methodology for calculating the VOS tariff to the PUC by January 31, 2014. Utilities adopting the VOS will be required to follow this methodology when calculating the VOS tariff. Commerce selected Clean Power Research (CPR) to support the process of developing the methodology, and additionally held four public workshops to develop, present, and receive feedback.

The 2013 legislation specifically mandated that the VOS legislation take into account the following values of distributed PV: energy and its delivery; generation capacity; transmission capacity; transmission and distribution line losses; and environmental value. The legislation also mandated a method of implementation, whereby solar customers will be billed for their gross electricity consumption under their applicable tariff, and will receive a VOS credit for their gross solar electricity production.

The present document provides the methodology to be used by participating utilities. It is based on the enabling statute, stakeholder input, and guidance from Commerce. It includes a detailed example calculation for each step of the calculation.

Key aspects of the methodology include:

- A standard PV rating convention
- Methods for creating an hourly PV production time-series, representing the aggregate output of all PV systems in the service territory per unit capacity corresponding to the output of a PV resource on the margin
- Requirements for calculating the electricity losses of the transmission and distribution systems
- Methods for performing technical calculations for avoided energy, effective generation capacity and effective distribution capacity
- Economic methods for calculating each value component (e.g., avoided fuel cost, capacity cost, etc.)
- Requirements for summarizing input data and final calculations in order to facilitate PUC and stakeholder review

Application of the methodology results in the creation of two tables: the VOS Data Table (a table of utility-specific input assumptions) and the VOS Calculation Table (a table of utility-specific total value of

[1] MN Laws 2013, Chapter 85 HF 729, Article 9, Section 10.

solar). Together these two tables ensure transparency and facilitate understanding among stakeholders and regulators.

The VOS Calculation Table is illustrated in Figure ES-1. The table shows each value component and how the gross economic value of each component is converted into a distributed solar value. The process uses a component-specific load match factor (where applicable) and a component-specific loss savings factor. The values are then summed to yield the 25-year levelized value.

Figure ES-1. VOS Calculation Table: economic value, load match, loss savings and distributed PV value.

25 Year Levelized Value	Economic Value ($/kWh)	X	Load Match (No Losses) (%)	X	(1	+	Distributed Loss Savings (%)	)	=	Distributed PV Value ($/kWh)
Avoided Fuel Cost	E1						DLS-Energy			V1
Avoided Plant O&M - Fixed	E2		ELCC				DLS-ELCC			V2
Avoided Plant O&M - Variable	E3						DLS-Energy			V3
Avoided Gen Capacity Cost	E4		ELCC				DLS-ELCC			V4
Avoided Reserve Capacity Cost	E5		ELCC				DLS-ELCC			V5
Avoided Trans. Capacity Cost	E6		ELCC				DLS-ELCC			V6
Avoided Dist. Capacity Cost	E7		PLR				DLS-PLR			V7
Avoided Environmental Cost	E8						DLS-Energy			V8
Avoided Voltage Control Cost										
Solar Integration Cost										
										Lev. VOS

As a final step, the methodology calls for the conversion of the 25-year levelized value to an equivalent inflation-adjusted credit. The utility would then use the first year value as the credit for solar customers, and would adjust each year using the latest Consumer Price Index (CPI) data.

Contents

Introduction

Background

Minnesota passed legislation[2] in 2013 that allows Investor-Owned Utilities (IOUs) to apply to the Public Utility Commission (PUC) for a Value of Solar (VOS) tariff as an alternative to net metering, and as a rate identified for community solar gardens. The Department of Commerce (Commerce) was assigned the responsibility of developing and submitting a methodology for calculating the VOS tariff to the PUC by January 31, 2014. Utilities adopting the VOS will be required to follow this methodology when calculating the VOS rate. Commerce selected Clean Power Research (CPR) to support the process of developing the methodology, and additionally held four public workshops to develop, present, and receive feedback.

The present document provides the VOS methodology to be used by participating utilities. It is based on the enabling statute, stakeholder input and guidance from Commerce.

Purpose

The State of Minnesota has identified a VOS tariff as a potential replacement for the existing Net Energy Metering (NEM) policy that currently regulates the compensation of home and business owners for electricity production from PV systems. As such, the adopted VOS legislation is not an incentive for distributed PV, nor is it intended to eliminate or prevent current or future incentive programs.

While NEM effectively values PV-generated electricity at the customer retail rate, a VOS tariff seeks to quantify the value of distributed PV electricity. If the VOS is set correctly, it will account for the real value of the PV-generated electricity, and the utility and its ratepayers would be indifferent to whether the electricity is supplied from customer-owned PV or from comparable conventional means. Thus, a VOS tariff eliminates the NEM cross-subsidization concerns. Furthermore, a well-constructed VOS tariff could provide market signals for the adoption of technologies that significantly enhance the value of electricity from PV, such as advanced inverters that can assist the grid with voltage regulation.

VOS Calculation Table Overview

The VOS is the sum of several distinct value components, each calculated separately using procedures defined in this methodology. As illustrated in Figure 1, the calculation includes a gross component value, a component-dependent load-match factor (as applicable for capacity related values) and a component-dependent Loss Savings Factor.

[2] MN Laws 2013, Chapter 85 HF 729, Article 9, Section 10.

For example, the avoided fuel cost does not have a load match factor because it is not dependent upon performance at the highest hours (fuel costs are avoided during all PV operating hours). Avoided fuel cost does have a Loss Savings Factor, however, accounting for loss savings in both transmission and distribution systems. On the other hand, the Avoided Distribution Capacity Cost has an important Load Match Factor (shown as Peak Load Reduction, or 'PLR') and a Loss Savings Factor that only accounts for distribution (not transmission) loss savings.

Gross Values, Distributed PV Values, and the summed VOS shown in Figure 1 are all 25-year levelized values denominated in dollars per kWh.

Figure 1. Illustration of the VOS Calculation Table

25 Year Levelized Value	Economic Value ($/kWh)	x	Load Match (No Losses) (%)	x	(1 +	Distributed Loss Savings (%)	)	=	Distributed PV Value ($/kWh)
Avoided Fuel Cost	E1					DLS-Energy			V1
Avoided Plant O&M - Fixed	E2		ELCC			DLS-ELCC			V2
Avoided Plant O&M - Variable	E3					DLS-Energy			V3
Avoided Gen Capacity Cost	E4		ELCC			DLS-ELCC			V4
Avoided Reserve Capacity Cost	E5		ELCC			DLS-ELCC			V5
Avoided Trans. Capacity Cost	E6		ELCC			DLS-ELCC			V6
Avoided Dist. Capacity Cost	E7		PLR			DLS-PLR			V7
Avoided Environmental Cost	E8					DLS-Energy			V8
Avoided Voltage Control Cost									
Solar Integration Cost									
									Lev. VOS

VOS Rate Implementation

Separation of Usage and Production

Minnesota's VOS legislation mandates that, if a VOS tariff is approved, solar customers will be billed for all usage under their existing applicable tariff, and will receive a VOS credit for their gross solar energy production. Separating usage (charges) from production (credits) simplifies the rate process for several reasons:

- Customers will be billed for all usage. Energy derived from the PV systems will not be used to offset ("net") usage prior to calculating charges. This will ensure that utility infrastructure costs will be recovered by the utilities as designed in the applicable retail tariff.
- The utility will provide all energy consumed by the customer. Standby charges for customers with on-site PV systems are not permitted under a VOS rate.
- The rates for usage can be adjusted in future ratemaking.

VOS Components

The definition and selection of VOS components were based on the following considerations:

- Components corresponding to minimum statutory requirements are included. These account for the "value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value."
- Non-required components were selected only if they were based on known and measurable evidence of the cost or benefit of solar operation to the utility.
- Environmental costs are included as a required component, and are based on existing Minnesota and federal externality costs.
- Avoided fuel costs are based on long-term risk-free fuel supply contracts. This value implicitly includes both the avoided cost of fuel, as well as the avoided cost of price volatility risk that is otherwise passed from the utility to customers through fuel price adjustments.
- Credit for systems installed at high value locations (identified in the legislation as an option) is included as an option for the utility. It is not a separate VOS component but rather is implemented using a location-specific distribution capacity value (the component most affected by location). This is addressed in the Distribution Capacity Cost section.
- Voltage control and solar integration (a cost) are kept as "placeholder" components for future years. Methodologies are not provided, but these components may be developed for the future. Voltage control benefits are anticipated but will first require implementation of recent changes to national interconnection standards. Solar integration costs are expected to be small, but possibly measureable. Further research will be required on this topic.

Table 1 presents the VOS components selected by Commerce and the cost basis for each component. Table 2 presents the VOS components that were considered but not selected by Commerce. Selections were made based on requirements and guidance in the enabling statute, and were informed by stakeholder comments (including those from Minnesota utilities; local and national solar and environmental organizations; local solar manufacturers and installers; and private parties) and workshop discussions. Stakeholders participated in four public workshops and provided comments through workshop panels, workshop Q&A sessions and written comments.

Table 1. VOS components included in methodology.

Value Component	Basis	Legislative Guidance	Notes
Avoided Fuel Cost	Energy market costs (portion attributed to fuel)	Required (energy)	Includes cost of long-term price risk
Avoided Plant O&M Cost	Energy market costs (portion attributed to O&M)	Required (energy)	
Avoided Generation Capacity Cost	Capital cost of generation to meet peak load	Required (capacity)	
Avoided Reserve Capacity Cost	Capital cost of generation to meet planning margins and ensure reliability	Required (capacity)	
Avoided Transmission Capacity Cost	Capital cost of transmission	Required (transmission capacity)	
Avoided Distribution Capacity Cost	Capital cost of distribution	Required (delivery)	
Avoided Environmental Cost	Externality costs	Required (environmental)	
Voltage Control	Cost to regulate distribution (future inverter designs)		Future (TBD)
Integration Cost[3]	Added cost to regulate system frequency with variable solar		Future (TBD)

[3] This is not a value, but a cost. It would reduce the VOS rate if included.

Table 2. VOS components not included in methodology.

Value Component	Basis	Legislative Guidance	Notes
Credit for Local Manufacturing/ Assembly	Local tax revenue tied to net solar jobs	Optional (identified in legislation)	
Market Price Reduction	Cost of wholesale power reduced in response to reduction in demand		
Disaster Recovery	Cost to restore local economy (requires energy storage and islanding inverters)		

Solar Penetration

Solar penetration refers to the total installed capacity of PV on the grid, generally expressed as a percentage of the grid's total load. The level of solar penetration on the grid is important because it affects the calculation of the Effective Load Carrying Capability (ELCC) and Peak Load Reduction (PLR) load-match factors (described later).

In the methodology, the near-term level of PV penetration is used. This is done so that the capacity-related value components will reflect the near-term level of PV penetration on the grid. However, the change in PV penetration level will be accounted for in the annual adjustment to the VOS. To the extent that PV penetration increases, future VOS rates will reflect higher PV penetration levels.

Marginal Fuel

This methodology assumes that PV displaces natural gas during PV operating hours. This is consistent with current and projected MISO market experience. During some hours of the year, other fuels (such as coal) may be the fuel on the margin. In these cases, natural gas displacement is a simplifying assumption that is not expected to materially impact the calculated VOS tariff. However, if future analysis indicates that the assumption is not warranted, then the methodology may be modified accordingly. For example, by changing the methodology to include displacement of coal production, avoided fuel costs may decrease and avoided environmental costs may increase.

Economic Analysis Period

In evaluating the value of a distributed PV resource, the economic analysis period is set at 25 years, the assumed useful service life of the PV system[4]. The methodology includes PV degradation effects as described later.

Annual VOS Tariff Update

Each year, a new VOS tariff would be calculated using current data, and the new resulting VOS rate would be applicable to all customers entering the tariff during the year. Changes such as increased or decreased fuel prices and modified hourly utility load profiles due to higher solar penetration will be incorporated into each new annual calculation.

Customers who have already entered into the tariff in a previous year will not be affected by this annual adjustment. However, customers who have entered into a tariff in prior years will see their Value of Solar rates adjusted for the previous year’s inflation rate as described later.

Commerce may also update the methodology to use the best available practices, as necessary.

Transparency Elements

The methodology incorporates two tables that are to be included in a utility’s application to the Minnesota PUC for the use of a VOS tariff. These tables are designed to improve transparency and facilitate understanding among stakeholders and regulators.

- **VOS Data Table.** This table provides a utility-specific defined list of the key input assumptions that go into the VOS tariff calculation. This table is described in more detail later.
- **VOS Calculation Table.** This table includes the list of value components and their gross values, their load-match factors, their Loss Savings Factors, and the computation of the total levelized value.

Glossary

A glossary is provided at the end of this document defining some of the key terms used throughout this document.

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[4] NREL: Solar Resource Analysis and High-Penetration PV Potential (April 2010). http://www.nrel.gov/docs/fy10osti/47956.pdf

Methodology: Assumptions

Fixed Assumptions

Table 3 and Table 4 present fixed assumptions, common to all utilities and incorporated into this methodology, that are to be applied to the calculation of 2014 VOS tariffs. These may be updated by Commerce in future years as necessary when performing the annual VOS update. Table 4 is described in more detail in the Avoided Environmental Cost subsection. Table terms can be found in the Glossary.

The general escalation rate is calculated as the average annual inflation rate over the last 25 years. The methodology uses the U.S. Bureau of Labor Statistics' Urban Consumer Price Index (CPI) data.

To retrieve Urban CPI data follow these steps:

1. Go to the U.S. Bureau of Labor Statistics's Top Picks for Consumer Price Index – All Urban Consumers[5]

2. Select " U.S. All items, 1982-84=100 - CUUR0000SA0". Click the "Retrieve Data" button near the bottom of the page.

3. Across from "Change Output Options", change the "from" and "to" years to capture the last 25 years of annual average CPI data. For example, a VOS rate calculated in 2014 would enter 1998 ("from" year) and 2013 ("to" year). Click on "go" to generate the data for this time period.

4. Select the annual average CPI numbers for the first and last year of the 25 year period. These numbers are under the "Annual" column. For example, the 1988 annual CPI factor is 118.3, and the 2013 factor is 232.957.

5. Use the annual CPI factors in equation (1) to calculate the 25 year average annual inflation rate.

$$25yrAvgAnnualInflation = \left(\frac{AnnualAvg_{year(-1)}\ UCPI}{AnnualAvg_{year(-26)}\ UCPI}\right)^{1/(25)} - 1 \tag{1}$$

$$25yrAvgAnnualInflation = \left(\frac{AnnualAvg_{2013}\ UCPI}{AnnualAvg_{1998}\ UCPI}\right)^{1/(25)} - 1 = \left[\left(\frac{232.957}{118.300}\right)^{1/25} - 1\right] = 2.75\% \tag{2}$$

[5] CPI data can currently be found at: http://data.bls.gov/cgi-bin/surveymost?cu

Table 3. Fixed assumptions used in Methodology's Example VOS calculations

Guaranteed NG Fuel Prices						
Year				**Environmental Externalities**		
2014	$3.93	$ per MMBtu		Environmental discount rate (nominal)	5.83%	per year
2015	$4.12	$ per MMBtu		Environmental costs	(shown in separate table)	
2016	$4.25	$ per MMBtu				
2017	$4.36	$ per MMBtu		**Economic Assumptions**		
2018	$4.50	$ per MMBtu		General escalation rate	2.75%	per year
2019	$4.73	$ per MMBtu				
2020	$5.01	$ per MMBtu				
2021	$5.33	$ per MMBtu		**Treasury Yields**		
2022	$5.67	$ per MMBtu		1 Year	0.13%	
2023	$6.02	$ per MMBtu		2 Year	0.29%	
2024	$6.39	$ per MMBtu		3 Year	0.48%	
2025	$6.77	$ per MMBtu		5 Year	1.01%	
				7 Year	1.53%	
PV Assumptions				10 Year	2.14%	
PV degradation rate	0.50%	per year		20 Year	2.92%	
PV life	25	years		30 Year	3.27%	

Table 4. Environmental externality costs by year.

Year	Analysis Year	CO_2 Cost ($/MMBtu)	PM10 Cost ($/MMBtu)	CO Cost ($/MMBtu)	NO_x Cost ($/MMBtu)	Pb Cost ($/MMBtu)	Total Cost ($/MMBtu)
2014	0	1.939	0.069	0.000	0.013	0.000	2.022
2015	1	2.046	0.071	0.000	0.013	0.000	2.131
2016	2	2.158	0.073	0.000	0.014	0.000	2.245
2017	3	2.274	0.075	0.000	0.014	0.000	2.363
2018	4	2.395	0.077	0.000	0.015	0.000	2.487
2019	5	2.521	0.079	0.000	0.015	0.000	2.615
2020	6	2.652	0.082	0.000	0.015	0.000	2.749
2021	7	2.788	0.084	0.000	0.016	0.000	2.888
2022	8	2.930	0.086	0.000	0.016	0.000	3.032
2023	9	3.077	0.089	0.000	0.017	0.000	3.182
2024	10	3.230	0.091	0.000	0.017	0.000	3.338
2025	11	3.390	0.093	0.000	0.018	0.000	3.501
2026	12	3.555	0.096	0.000	0.018	0.000	3.669
2027	13	3.653	0.099	0.000	0.019	0.000	3.770
2028	14	3.830	0.101	0.000	0.019	0.000	3.950
2029	15	4.014	0.104	0.000	0.020	0.000	4.138
2030	16	4.205	0.107	0.000	0.020	0.000	4.332
2031	17	4.404	0.110	0.000	0.021	0.000	4.534
2032	18	4.610	0.113	0.000	0.021	0.000	4.744
2033	19	4.824	0.116	0.000	0.022	0.000	4.962
2034	20	5.047	0.119	0.000	0.023	0.000	5.189
2035	21	5.278	0.123	0.000	0.023	0.000	5.424
2036	22	5.518	0.126	0.000	0.024	0.000	5.668
2037	23	5.768	0.129	0.000	0.024	0.000	5.922
2038	24	6.027	0.133	0.000	0.025	0.000	6.185

See explanation in the Avoided Environmental Cost section.

Utility-Specific Assumptions and Calculations

Some assumptions and calculations are unique to each utility. These include economic assumptions (such as discount rate) and technical calculations (such as ELCC). Utility-specific assumptions and calculations are determined by the utility, and are included in the VOS Data Table, a required transparency element.

The utility-specific calculations (such as capacity-related transmission capital cost) are determined using the methods described in this methodology.

An example VOS Data Table, showing the parameters to be included in the utility filing for the VOS tariff, is shown in Table 5. This table includes values that are given for example only. These example values carry forward in the example calculations.

Table 5. VOS Data Table (EXAMPLE DATA) — required format showing example parameters used in the example calculations.

	Input Data	Units
Economic Factors		
Start Year for VOS applicability	2014	
Discount rate (WACC)	8.00%	per year
Load Match Analysis (see calculation method)		
ELCC (no loss)	40%	% of rating
PLR (no loss)	30%	% of rating
Loss Savings – Energy	8%	% of PV output
Loss Savings – PLR	5%	% of PV output
Loss Savings – ELCC	9%	% of PV output
PV Energy (see calculation method)		
First year annual energy	1800	kWh per kW-AC
Transmission (see calculation method)		
Capacity-related transmission capital cost	$33	$ per kW-yr

	Input Data	Units
Power Generation		
Peaking CT, simple cycle		
Installed cost	900	$/kW
Heat rate	9,500	BTU/kWh
Intermediate peaking CCGT		
Installed cost	1,200	$/kW
Heat rate	6,500	BTU/kWh
Other		
Solar-weighted heat rate (see calc. method)	8000	BTU per kWh
Fuel Price Overhead	$0.50	$ per MMBtu
Generation life	50	years
Heat rate degradation	0.100%	per year
O&M cost (first Year) - Fixed	$5.00	per kW-yr
O&M cost (first Year) - Variable	$0.0010	$ per kWh
O&M cost escalation rate	2.00%	per year
Reserve planning margin	15%	
Distribution		
Capacity-related distribution capital cost	$200	$ per kW
Distribution capital cost escalation	2.00%	per year
Peak load	5000	MW
Peak load growth rate	1.00%	per year

Methodology: Technical Analysis

Load Analysis Period

The VOS methodology requires that a number of technical parameters (PV energy production, effective load carrying capability (ELCC) and peak load reduction (PLR) load-match factors, and electricity-loss factors) be calculated over a fixed period of time in order to account for day-to-day variations and seasonal effects, such as changes in solar radiation. For this reason, the load analysis period must cover a period of at least one year.

The data may start on any day of the year, and multiple years may be included, as long as all included years are contiguous and each included year is a complete one-year period. For example, valid load analysis periods may be 1/1/2012 0:00 to 12/31/2012 23:00 or 11/1/2010 0:00 to 10/31/2013 23:00.

Three types of time series data are required to perform the technical analysis:

- **Hourly Generation Load:** the hourly utility load over the Load Analysis Period. This is the sum of utility generation and import power needed to meet all customer load.
- **Hourly Distribution Load:** the hourly distribution load over the Load Analysis Period. The distribution load is the power entering the distribution system from the transmission system (i.e., generation load minus transmission losses).
- **Hourly PV Fleet Production:** the hourly PV Fleet production over the Load Analysis Period. The PV fleet production is the aggregate generation of all of the PV systems in the PV fleet.

All three types of data must be provided as synchronized, time-stamped hourly values of average power over the same period, and corresponding to the same hourly intervals. Data must be available for every hour of the Load Analysis Period.

PV data using Typical Meteorological Year data is not time synchronized with time series production data, so it should not be used as the basis for PV production.

Data that is not in one-hour intervals must be converted to hourly data (for example, 15-minute meter data would have to be combined to obtain 1-hour data). Also, data values that represent energy must be converted to average power.

If data is missing or deemed erroneous for any time period less than or equal to 24 hours, the values corresponding to that period may be replaced with an equal number of values from the same time interval on the previous or next day if it contains valid data. This data replacement method may be used provided that it does not materially affect the results.

PV Energy Production

PV System Rating Convention

The methodology uses a rating convention for PV capacity based on AC delivered energy (not DC), taking into account losses internal to the PV system. A PV system rated output is calculated by multiplying the number of modules by the module PTC rating[6] [as listed by the California Energy Commission (CEC)[7]] to account for module de-rate effects. The result is then multiplied by the CEC-listed inverter efficiency rating[8] to account for inverter efficiency, and the result is multiplied by a loss factor to account for internal PV array losses (wiring losses, module mismatch and other losses).

If no CEC module PTC rating is available, the module PTC rating should be calculated as 0.90 times the module STC rating[9]. If no CEC inverter efficiency rating is available, an inverter efficiency of 0.95 should be used. If no measured or design loss factor is available, 0.85 should be used.

To summarize: [10]

Rating (kW-AC) = [Module Quantity] x [Module PTC rating (kW)] x [Inverter Efficiency Rating] x [Loss Factor]

Hourly PV Fleet Production

Hourly PV Fleet Production can be obtained using any one of the following three options:

1. Utility Fleet - Metered Production. Fleet production data can be created by combining actual metered production data for every PV system in the utility service territory, provided that there are a sufficient number of systems[11] installed to accurately derive a correct representation of aggregate PV production. Such metered data is to be gross PV output on the AC side of the

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[6] PTC refers to PVUSA Test Conditions, which were developed to test and compare PV systems as part of the PVUSA (Photovoltaics for Utility Scale Applications) project. PTC are 1,000 Watts per square meter solar irradiance, 20 degrees C air temperature, and wind speed of 1 meter per second at 10 meters above ground level. PV manufacturers use Standard Test Conditions, or STC, to rate their PV products.

[7] CEC module PTC ratings for most modules can be found at: http://www.gosolarcalifornia.ca.gov/equipment/pv_modules.php

[8] CEC inverter efficiency ratings for most inverters can be found at: http://www.gosolarcalifornia.ca.gov/equipment/inverters.php

[9] PV manufacturers use Standard Test Conditions, or STC, to rate their PV products. STC are 1,000 Watts per square meter solar irradiance, 25 degrees C cell temperature, air mass equal to 1.5, and ASTM G173-03 standard spectrum.

[10] In some cases, this equation will have to be adapted to account for multiple module types and/or inverters. In such cases, the rating of each subsystem can be calculated independently and then added.

[11] A sufficient number of systems has been achieved when adding a single system of random orientation, tilt, tracking characteristics, and capacity (within reason) does not materially change the observed hourly PV Fleet Shape (see next subsection of PV Fleet Shape definition).

system, but before local customer loads are subtracted (i.e., PV must be separately metered from load). Metered data from individual systems is then aggregated by summing the measured output for all systems for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.

2. Utility Fleet, Simulated Production. If metered data is not available, the aggregate output of all distributed PV systems in the utility service territory can be modeled using PV system technical specifications and hourly irradiance and temperature data. These systems must be deployed in sufficient numbers to accurately derive a correct representation of aggregate PV production. Modeling must take into account the system's location and each array's tracking capability (fixed, single-axis or dual-axis tracking), orientation (tilt and azimuth), module PTC ratings, inverter efficiency and power ratings, other loss factors and the effect of temperature on module output. Technical specifications for each system must be available to enable such modeling. Modeling must also make use of location-specific, time-correlated, measured or satellite-derived plane of array irradiance data. Ideally, the software will also support modeling of solar obstructions.
   - To make use of this option, detailed system specifications for every PV system in the utility's service territory must be obtained. At a minimum, system specifications must include:
     - Location (latitude and longitude)
     - System component ratings (e.g., module ratings an inverter ratings)
     - Tilt and azimuth angles
     - Tracking type (if applicable)
   - After simulating the power production for each system for each hour in the Load Analysis Period, power production must be aggregated by summing the power values for all systems for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.

3. Expected Fleet, Simulated Production. If neither metered production data nor detailed PV system specifications are available, a diverse set of PV resources can be estimated by simulating groups of systems at major load centers in the utility's service territory with some assumed fleet configuration. To use this method, one or more of the largest load centers in the utility service territory may be used. If a single load center accounts for a high percentage of the utility's total load, a single location will suffice. If there are several large load centers in the territory, groups of systems can be created at each location with capacities proportional to the load in that area.
   - For each location, simulate multiple systems, each rated in proportion to the expected capacity, with azimuth and tilt angles such as the list of systems presented in Table 6. Note

that the list of system configurations should represent the expected fleet composition. No method is explicitly provided to determine the expected fleet composition; however, a utility could analyze the fleet composition of PV fleets outside of its territory.

Table 6. (EXAMPLE) Azimuth and tilt angles

System	Azimuth	Tilt	% Capacity
1	90	20	3.5
2	135	15	3.0
3	135	30	6.5
4	180	0	6.0
5	180	15	16.0
6	180	25	22.5
7	180	35	18.0
8	235	15	8.5
9	235	30	9.0
10	270	20	7.0

- Simulate each of the PV systems for each hour in the Load Analysis Period. Aggregate power production for the systems is obtained by summing the power values for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.
- If the utility elects to perform a location-specific analysis for the Avoided Distribution Capacity Costs, then it should also take into account what the geographical distribution of the expected PV fleet would be. Again, this could be done by analyzing a PV fleet composition outside of the utility's territory. An alternative method that would be acceptable is to distribute the expected PV fleet across major load centers. Thereby assuming that PV capacity is likely to be added where significant load (and customer density) already exists.
- Regardless of location count and location weighting, the total fleet rating is taken as the sum of the individual system ratings.

PV Fleet Shape

Regardless of which of the three methods is selected for obtaining the Hourly PV Fleet production, the next step is divide each hour's value by the PV Fleet's aggregate AC rating to obtain the PV Fleet Shape. The units of the PV Fleet Shape are kWh per hour per kW-AC (or, equivalently, average kW per kW-AC).

Marginal PV Resource

The PV Fleet Shape is hourly production of a Marginal PV Resource having a rating of 1 kW-AC.

Annual Avoided Energy

Annual Avoided Energy (kWh per kW-AC per year) is the sum of the hourly PV Fleet Shape across all hours of the Load Analysis Period, divided by the numbers of years in the Load Analysis Period. The result is the annual output of the Marginal PV Resource.

$$Annual\ Avoided\ Energy\ (kWh) = \frac{\sum Hourly\ PV\ Fleet\ Production_h}{NumberOfYearsInLoadAnalysisPeriod} \qquad (3)$$

- Defined in this way, the Annual Avoided Energy does not include the effects of loss savings. As described in the Loss Analysis subsection, however, it will have to be calculated for the two loss cases (with losses and without losses).

Load-Match Factors

Capacity-related benefits are time dependent, so it is necessary to evaluate the effectiveness of PV in supporting loads during the critical peak hours. Two different measures of effective capacity are used:

- Effective Load Carrying Capability (ELCC)
- Peak Load Reduction (PLR)

Near term PV penetration levels are used in the calculation of the ELCC and PLR values so that the capacity-related value components will reflect the near term level of PV penetration on the grid. However, the ELCC and PLR will be re-calculated during the annual VOS adjustment and thus reflect any increase in future PV Penetration Levels.

Effective Load Carrying Capability (ELCC)

The Effective Load Carrying Capability (ELCC) is the measure of the effective capacity for distributed PV that can be applied to the avoided generation capacity costs, the avoided reserve capacity costs, the avoided generation fixed O&M costs, and the avoided transmission capacity costs (see Figure 1).

Using current MISO rules for non-wind variable generation (MISO BPM-011, Section 4.2.2.4, page 35)[12]: the ELCC will be calculated from the PV Fleet Shape for hours ending 2pm, 3pm, and 4pm Central Standard Time during June, July, and August over the most recent three years. If three years of data are unavailable, MISO requires "a minimum of 30 consecutive days of historical data during June, July, or August" for the hours ending 2pm, 3pm and 4pm Central Standard Time.

The ELCC is calculated by averaging the PV Fleet Shape over the specified hours, and then dividing by the rating of the Marginal PV Resource (1 kW-AC), which results in a percentage value. Additionally, the ELCC must be calculated for the two loss cases (with and without T&D losses, as described in the Loss Analysis subsection).

Peak Load Reduction (PLR)

The PLR is defined as the maximum distribution load over the Load Analysis Period (without the Marginal PV Resource) minus the maximum distribution load over the Load Analysis Period (with the Marginal PV Resource). The distribution load is the power entering the distribution system from the transmission system (i.e., generation load minus transmission losses). In calculating the PLR, it is not sufficient to limit modeling to the peak hour. All hours over the Load Analysis Period must be included in the calculation. This is because the reduced peak load may not occur in the same hour as the original peak load.

The PLR is calculated as follows. First, determine the maximum Hourly Distribution Load (D1) over the Load Analysis Period. Next, create a second hourly distribution load time series by subtracting the effect of the Marginal PV Resource, i.e., by evaluating what the new distribution load would be each hour given the PV Fleet Shape. Next, determine the maximum load in the second time series (D2). Finally, calculate the PLR by subtracting D2 from D1.

In other words, the PLR represents the capability of the Marginal PV Resource to reduce the peak distribution load over the Load Analysis Period. PLR is expressed in kW per kW-AC.

Additionally, the PLR must be calculated for the two loss cases (with distribution losses and without distribution losses, as described in the Loss Analysis subsection).

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[12] https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

Loss Savings Analysis

In order to calculate the required Loss Savings Factors on a marginal basis as described below, it will be necessary to calculate ELCC, PLR and Annual Avoided Energy each twice. They should be calculated first by *including* the effects of avoided marginal losses, and second by *excluding* them. For example, the ELCC would first be calculated by including avoided transmission and distribution losses, and then re-calculated assuming no losses, i.e., as if the Marginal PV Resource was a central (not distributed) resource.

The calculations should observe the following

Table 7. Losses to be considered.

Technical Parameter	Loss Savings Considered
Avoided Annual Energy	Avoided transmission and distribution losses for every hour of the load analysis period.
ELCC	Avoided transmission and distribution losses during the MISO defined hours.
PLR	Avoided distribution losses (not transmission) at peak.

When calculating avoided marginal losses, the analysis must satisfy the following requirements:

1. Avoided losses are to be calculated on an hourly basis over the Load Analysis Period. The avoided losses are to be calculated based on the generation (and import) power during the hour and the expected output of the Marginal PV Resource during the hour.

2. Avoided losses in the transmission system and distribution systems are to be evaluated separately using distinct loss factors based on the most recent study data available.

3. Avoided losses should be calculated on a marginal basis. The marginal avoided losses are the difference in hourly losses between the case without the Marginal PV Resource, and the case with the Marginal PV Resource. Avoided average hourly losses are not calculated. For example, if the Marginal PV Resource were to produce 1 kW of power for an hour in which total customer load is 1000 kW, then the avoided losses would be the calculated losses at 1000 kW of customer load minus the calculated losses at 999 kW of load.

4. Distribution losses should be based on the power entering the distribution system, after transmission losses.

5. Avoided transmission losses should take into account not only the marginal PV generation, but also the avoided marginal distribution losses.

6. Calculations of avoided losses should not include no-load losses (e.g., corona, leakage current). Only load-related losses should be included.

7. Calculations of avoided losses in any hour should take into account the non-linear relationship between losses and load (load-related losses are proportional to the square of the load, assuming constant voltage). For example, the total load-related losses during an hour with a load of 2X would be approximately 4 times the total load-related losses during an hour with a load of only X.

Loss Savings Factors

The Energy Loss Savings Factor (as a percentage) is defined for use within the VOS Calculation Table:

$$Annual\ Avoided\ Energy_{WithLosses} = Annual\ Avoided\ Energy_{WithoutLosses}\left(1 + Loss\ Savings_{Energy}\right) \tag{4}$$

Equation 5 is then rearranged to solve for the Energy Loss Savings Factor:

$$Loss\ Savings_{Energy} = \frac{Annual\ Avoided\ Energy_{WithLosses}}{Annual\ Avoided\ Energy_{WithoutLosses}} - 1 \tag{5}$$

Similarly, the PLR Loss Savings Factor is defined as:

$$Loss\ Savings_{PLR} = \frac{PLR_{WithLosses}}{PLR_{WithoutLosses}} - 1 \tag{6}$$

and the ELCC Loss Savings Factor is defined as:

$$Loss\ Savings_{ELCC} = \frac{ELCC_{WithLosses}}{ELCC_{WithoutLosses}} - 1 \tag{7}$$

Methodology: Economic Analysis

The following subsections provide a methodology for performing the economic calculations to derive gross values in $/kWh for each of the VOS components. These gross component values will then be entered into the VOS Calculation Table, which is the second of the two key transparency elements.

Important Note: The economic analysis is initially performed as if PV was centrally-located (without loss-saving benefits of distributed location) and with output perfectly correlated to load. Real-world adjustments are made later in the final VOS summation by including the results of the loss savings and load match analyses.

Discount Factors

By convention, the analysis year 0 corresponds to the year in which the VOS tariff will begin. As an example, if a VOS was done in 2013 for customers entering a VOS tariff between January 1, 2014 and December 31, 2014, then year 0 would be 2014, year 1 would be 2015, and so on.

For each year *i*, a discount factor is given by

$$DiscountFactor_i = \frac{1}{(1 + DiscountRate)^i} \qquad (8)$$

The *DiscountRate* is the utility Weighted Average Cost of Capital.

Similarly, a risk-free discount factor is given by:

$$RiskFreeDiscountFactor_i = \frac{1}{(1 + RiskFreeDiscountRate)^i} \qquad (9)$$

The *RiskFreeDiscountRate* is based on the yields of current Treasury securities[13] of 1, 2, 3, 5, 7, 10, 20, and 30 year maturation dates. The *RiskFreeDiscountRate* is used once in the calculation of the Avoided Fuel Costs.

Finally, an environmental discount factor is given by:

$$EnvironmentalDiscountFactor_i = \frac{1}{(1 + EnvironmentalDiscountRate)^i} \qquad (10)$$

[13] See http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

The *EnvironmentalDiscountRate* is based on the 3% *real* discount rate that has been determined to be an appropriate societal discount rate for future environmental benefits.[14] As the methodology requires a nominal discount rate, this 3% *real* discount rate is converted into its equivalent 5.61% nominal discount rate as follows:[15]

$$NominalDiscountRate = (1 + RealDiscountRate) \times (1 + GeneralEscalationRate) - 1 \quad (11)$$

The *EnvironmentalDiscountRate* is used once in the calculation of the Avoided Environmental Costs.

PV degradation is accounted for in the economic calculations by reductions of the annual PV production in future years. As such, the PV production in kWh per kW-AC for the marginal PV resource in year I is given by:

$$PVProduction_i = PVProduction_0 \times (1 - \mathrm{PVDegradationRate})^i \quad (12)$$

where PVDegradationRate is the annual rate of PV degradation, assumed to be 0.5% per year – the standard PV module warranty guarantees a maximum of 0.5% power degradation per annum. $PVProduction_0$ is the Annual Avoided Energy for the Marginal PV Resource.

PV capacity in year *i* for the Marginal PV Resource, taking into account degradation, equals:

$$PVCapacity_i = (1 - \mathrm{PVDegradationRate})^i \quad (13)$$

Avoided Fuel Cost

Avoided fuel costs are based on long-term, risk-free fuel supply contracts. This value implicitly includes both the avoided cost of fuel as well as the avoided cost of price volatility risk that is otherwise passed from the utility to customers through fuel price adjustments.

PV displaces energy generated from the marginal unit, so it avoids the cost of fuel associated with this generation. Furthermore, the PV system is assumed to have a service life of 25 years, so the uncertainty in fuel price fluctuations is also eliminated over this period. For this reason, the avoided fuel cost must take into account the fuel as if it were purchased under a guaranteed, long term contract.

[14] http://www.epa.gov/oms/climate/regulations/scc-tsd.pdf
[15] http://en.wikipedia.org/wiki/Nominal_interest_rate

The methodology provides for three options to accomplish this:

- **Futures Market.** This option is described in detail below, and is based on the NYMEX NG futures with a fixed escalation for years beyond the 12-year trading period.

- **Long Term Price Quotation.** This option is identical to the above option, except the input pricing data is based on an actual price quotation from an AA-rated NG supplier to lock in prices for the 25-year guaranteed period.

- **Utility-guaranteed Price.** This is the 25-year fuel price that is guaranteed by the utilities. Tariffs using the utility guaranteed price will include a mechanism for removing the usage fuel adjustment charges and provide fixed prices over the term.

Table 8 presents the calculation of the economic value of avoided fuel costs.

For the Futures Market option, Guaranteed NG prices are calculated as follows. Prices for the first 12 years are based on NYMEX natural gas futures quotes. These quotes are published daily by the CME Group.[16]

Guaranteed NG prices are calculated by following these steps:

1. First, monthly prices are determined by averaging the 30 days of NYMEX prices for each month, starting with the most recent 30 daily prices and then repeating the same 30-day averaging for every other contract month of the 12 year period. If a utility calculating a VOS rate does not have historical daily NYMEX prices already collected internally they can obtain this data by recording quotes for 30 days. The timing of the data collection should be accounted for in planning the VOS rate calculation.

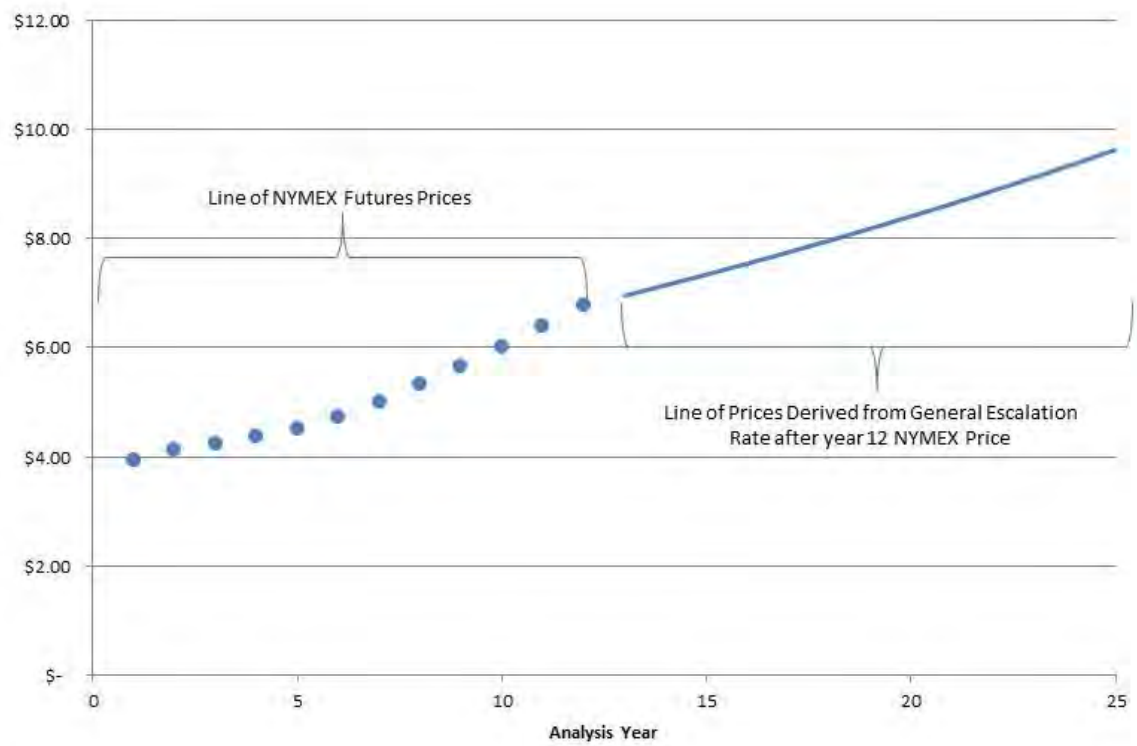
2. Then, the monthly prices are averaged to give a 12-month average in $ per MMBtu, resulting in the first 12 annual prices in the set of 25 annual prices. Prices for years beyond this NYMEX limit are calculated by applying the general escalation rate. An assumed fuel price overhead amount, escalated by year using the general escalation rate, is added to the fuel price to give the burnertip fuel price.

3. Prices for years 13 through 25 are calculated by escalating the year 12 annual average NYMEX quote by the general escalation rate annually for each year.

The guaranteed fuel prices for the methodology’s example calculation are shown in figure 2 below.

[16] CME Group’s Natural Gas (Henry Hub) Physical Futures Quotes can be found at: http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html.

Figure 2. (EXAMPLE) Guaranteed Fuel Prices



The first-year solar-weighted heat rate is calculated as follows:

$$SolarWeighedHeatRate_0 = \frac{\sum HeatRate_j \times FleetProduction_j}{\sum FleetProduction_j} \quad (14)$$

where the summation is over all hours *j* of the load analysis period, *HeatRate* is the actual heat rate of the plant on the margin, and *FleetProduction* is the Fleet Production Shape time series.

The solar-weighted heat rate for future years is calculated as:

$$SolarWeighedHeatRate_i = SolarWeighedHeatRate_0 \times (1 + \mathrm{HeatRateDegradationRate})^i \quad (15)$$

The utility price in year *i* is:

$$UtilityPrice_i = \frac{BurnertipFuelPrice_i \times SolarWeighedHeatRate_i}{10^6} \quad (16)$$

where the burnertip price is in $ per MMBtu and the heat rate is in Btu per kWh.

Utility cost is the product of the utility price and the per unit PV production. These costs are then discounted using the risk free discount rate and summed for all years. A risk-free discount rate (fitted to the US Treasury yields shown in Table 3) has been selected to account for the fact that there is no risk in the avoided fuel cost.

The VOS price (shown in red in Table 8) is the levelized amount that results in the same discounted amount as the utility price for the Avoided Fuel Cost component.

Table 8. (EXAMPLE) Economic Value of Avoided Fuel Costs.

				Prices			Costs			Disc. Costs	
Year	**Guaranteed NG Price**	**Burnertip NG Price**	**Heat Rate**	**Utility**	**VOS**	**p.u. PV Production**	**Utility**	**VOS**	**Discount Factor**	**Utility**	**VOS**
	($/MMBtu)	($/MMBtu)	(Btu/kWh)	($/kWh)	($/kWh)	(kWh)	($)	($)	**(risk free)**	($)	($)
2014	$3.93	$4.43	8000	$0.035	$0.056	1,800	$64	$101	1.000	$64	$101
2015	$4.12	$4.64	8008	$0.037	$0.056	1,791	$67	$100	0.999	$66	$100
2016	$4.25	$4.77	8016	$0.038	$0.056	1,782	$68	$100	0.994	$68	$99
2017	$4.36	$4.90	8024	$0.039	$0.056	1,773	$70	$99	0.986	$69	$98
2018	$4.50	$5.05	8032	$0.041	$0.056	1,764	$72	$99	0.971	$70	$96
2019	$4.73	$5.30	8040	$0.043	$0.056	1,755	$75	$98	0.951	$71	$94
2020	$5.01	$5.60	8048	$0.045	$0.056	1,747	$79	$98	0.927	$73	$91
2021	$5.33	$5.94	8056	$0.048	$0.056	1,738	$83	$97	0.899	$75	$88
2022	$5.67	$6.29	8064	$0.051	$0.056	1,729	$88	$97	0.872	$76	$85
2023	$6.02	$6.66	8072	$0.054	$0.056	1,721	$92	$96	0.842	$78	$81
2024	$6.39	$7.04	8080	$0.057	$0.056	1,712	$97	$96	0.809	$79	$78
2025	$6.77	$7.44	8088	$0.060	$0.056	1,703	$103	$96	0.786	$81	$75
2026	$6.95	$7.64	8097	$0.062	$0.056	1,695	$105	$95	0.762	$80	$72
2027	$7.14	$7.86	8105	$0.064	$0.056	1,686	$107	$95	0.737	$79	$70
2028	$7.34	$8.07	8113	$0.065	$0.056	1,678	$110	$94	0.713	$78	$67
2029	$7.54	$8.29	8121	$0.067	$0.056	1,670	$112	$94	0.688	$77	$64
2030	$7.75	$8.52	8129	$0.069	$0.056	1,661	$115	$93	0.663	$76	$62
2031	$7.96	$8.76	8137	$0.071	$0.056	1,653	$118	$93	0.637	$75	$59
2032	$8.18	$9.00	8145	$0.073	$0.056	1,645	$121	$92	0.612	$74	$56
2033	$8.41	$9.24	8153	$0.075	$0.056	1,636	$123	$92	0.587	$72	$54
2034	$8.64	$9.50	8162	$0.078	$0.056	1,628	$126	$91	0.563	$71	$51
2035	$8.88	$9.76	8170	$0.080	$0.056	1,620	$129	$91	0.543	$70	$49
2036	$9.12	$10.03	8178	$0.082	$0.056	1,612	$132	$90	0.523	$69	$47
2037	$9.37	$10.30	8186	$0.084	$0.056	1,604	$135	$90	0.504	$68	$45
2038	$9.63	$10.59	8194	$0.087	$0.056	1,596	$138	$89	0.485	$67	$43
							Validation: Present Value			**$1,826**	**$1,826**

Avoided Plant O&M – Fixed

Economic value calculations for fixed plant O&M are presented in Table 9. The first year fixed value is escalated at the O&M escalation rate for future years.

Similarly, PV capacity has an initial value of one during the first year because it is applicable to PV systems installed in the first year. Note that effective capacity (load matching) is handled separately, and this table represents the "ideal" resource, as if PV were able to receive the same capacity credit as a fully dispatchable technology.

The utility cost is the fixed O&M cost times the PV capacity divided by the utility capacity. Utility prices are the cost divided by the PV production. Costs are discounted using the utility discount factor and are summed for all years.

The VOS component value is calculated as before such that the discounted total is equal to the discounted utility cost.

Table 9. (EXAMPLE) Economic value of avoided plant O&M – fixed

Year	O&M Fixed	Utility Capacity	PV Capacity	Prices		p.u. PV Production	Costs		Discount Factor	Disc. Costs	
				Utility	VOS		Utility	VOS		Utility	VOS
	($/kW)	(p.u.)	(kW)	($/kWh)	($/kWh)	(kWh)	($)	($)		($)	($)
2014	$5.00	1.000	1.000	$0.003	$0.003	1800	$5	$6	1.000	$5	$6
2015	$5.11	0.999	0.995	$0.003	$0.003	1791	$5	$6	0.926	$5	$6
2016	$5.21	0.998	0.990	$0.003	$0.003	1782	$5	$6	0.857	$4	$5
2017	$5.32	0.997	0.985	$0.003	$0.003	1773	$5	$6	0.794	$4	$5
2018	$5.43	0.996	0.980	$0.003	$0.003	1764	$5	$6	0.735	$4	$4
2019	$5.55	0.995	0.975	$0.003	$0.003	1755	$5	$6	0.681	$4	$4
2020	$5.66	0.994	0.970	$0.003	$0.003	1747	$6	$6	0.630	$3	$4
2021	$5.78	0.993	0.966	$0.003	$0.003	1738	$6	$6	0.583	$3	$3
2022	$5.91	0.992	0.961	$0.003	$0.003	1729	$6	$6	0.540	$3	$3
2023	$6.03	0.991	0.956	$0.003	$0.003	1721	$6	$6	0.500	$3	$3
2024	$6.16	0.990	0.951	$0.003	$0.003	1712	$6	$6	0.463	$3	$3
2025	$6.29	0.989	0.946	$0.004	$0.003	1703	$6	$6	0.429	$3	$2
2026	$6.42	0.988	0.942	$0.004	$0.003	1695	$6	$6	0.397	$2	$2
2027	$6.55	0.987	0.937	$0.004	$0.003	1686	$6	$6	0.368	$2	$2
2028	$6.69	0.986	0.932	$0.004	$0.003	1678	$6	$6	0.340	$2	$2
2029	$6.83	0.985	0.928	$0.004	$0.003	1670	$6	$6	0.315	$2	$2
2030	$6.97	0.984	0.923	$0.004	$0.003	1661	$7	$6	0.292	$2	$2
2031	$7.12	0.983	0.918	$0.004	$0.003	1653	$7	$6	0.270	$2	$1
2032	$7.27	0.982	0.914	$0.004	$0.003	1645	$7	$5	0.250	$2	$1
2033	$7.42	0.981	0.909	$0.004	$0.003	1636	$7	$5	0.232	$2	$1
2034	$7.58	0.980	0.905	$0.004	$0.003	1628	$7	$5	0.215	$2	$1
2035	$7.74	0.979	0.900	$0.004	$0.003	1620	$7	$5	0.199	$1	$1
2036	$7.90	0.978	0.896	$0.004	$0.003	1612	$7	$5	0.184	$1	$1
2037	$8.07	0.977	0.891	$0.005	$0.003	1604	$7	$5	0.170	$1	$1
2038	$8.24	0.976	0.887	$0.005	$0.003	1596	$7	$5	0.158	$1	$1
							Validation: Present Value			**$67**	**$67**

Avoided Plant O&M – Variable

An example calculation of avoided plant O&M is displayed in Table 10. Utility prices are given in the VOS Data Table, escalated each year by the O&M escalation rate. As before, the per unit PV production is shown with annual degradation taken into account. The utility cost is the product of the utility price and the per unit production, and these costs are discounted. The VOS price of variable O&M is the levelized value resulting in the same total discounted cost.

Table 10. (EXAMPLE) Economic value of avoided plant O&M – variable.

	Prices			Costs			Disc. Costs	
Year	Utility ($/kWh)	VOS ($/kWh)	p.u. PV Production (kWh)	Utility ($)	VOS ($)	Discount Factor	Utility ($)	VOS ($)
2014	$0.001	$0.001	1,800	$2	$2	1.000	$2	$2
2015	$0.001	$0.001	1,791	$2	$2	0.926	$2	$2
2016	$0.001	$0.001	1,782	$2	$2	0.857	$2	$2
2017	$0.001	$0.001	1,773	$2	$2	0.794	$1	$2
2018	$0.001	$0.001	1,764	$2	$2	0.735	$1	$2
2019	$0.001	$0.001	1,755	$2	$2	0.681	$1	$1
2020	$0.001	$0.001	1,747	$2	$2	0.630	$1	$1
2021	$0.001	$0.001	1,738	$2	$2	0.583	$1	$1
2022	$0.001	$0.001	1,729	$2	$2	0.540	$1	$1
2023	$0.001	$0.001	1,721	$2	$2	0.500	$1	$1
2024	$0.001	$0.001	1,712	$2	$2	0.463	$1	$1
2025	$0.001	$0.001	1,703	$2	$2	0.429	$1	$1
2026	$0.001	$0.001	1,695	$2	$2	0.397	$1	$1
2027	$0.001	$0.001	1,686	$2	$2	0.368	$1	$1
2028	$0.001	$0.001	1,678	$2	$2	0.340	$1	$1
2029	$0.001	$0.001	1,670	$2	$2	0.315	$1	$1
2030	$0.001	$0.001	1,661	$2	$2	0.292	$1	$1
2031	$0.001	$0.001	1,653	$2	$2	0.270	$1	$1
2032	$0.001	$0.001	1,645	$2	$2	0.250	$1	$0
2033	$0.001	$0.001	1,636	$2	$2	0.232	$1	$0
2034	$0.001	$0.001	1,628	$2	$2	0.215	$1	$0
2035	$0.002	$0.001	1,620	$2	$2	0.199	$0	$0
2036	$0.002	$0.001	1,612	$2	$2	0.184	$0	$0
2037	$0.002	$0.001	1,604	$3	$2	0.170	$0	$0
2038	$0.002	$0.001	1,596	$3	$2	0.158	$0	$0

Validation: Present Value	$24	$24

Avoided Generation Capacity Cost

The solar-weighted capacity cost is based on the installed capital cost of a peaking combustion turbine and the installed capital cost of a combined cycle gas turbine, interpolated based on heat rate:

$$Cost = Cost_{CCGT} + (HeatRate_{PV} - HeatRate_{CCGT}) \times \frac{Cost_{CT} - Cost_{CCGT}}{HeatRate_{CT} - HeatRate_{CCGT}} \quad (17)$$

Where $HeatRate_{PV}$ is the solar-weighted heat rate calculated in equation (14).

Using equation (17) with the CT/CCGT heat rates and costs from the example VOS Data Table, we calculated a solar-weighted capacity cost of $1,050 per kW. In the example, the amortized cost is $86 per kW-yr.

Table 11 illustrates how utility costs are calculated by taking into account the degrading heat rate of the marginal unit and PV. For example, in year 2015, the utility cost is $86 per kW-yr x 0.999 / 0.995 to give $85 for each unit of effective PV capacity. Utility prices are back-calculated for reference from the per unit PV production. Again, the VOS price is selected to give the same total discounted cost as the utility costs for the Generation Capacity Cost component.

Table 11. (EXAMPLE) Economic value of avoided generation capacity cost.

				Prices			Costs			Disc. Costs	
Year	Capacity Cost	Utility Capacity	PV Capacity	Utility	VOS	p.u. PV Production	Utility	VOS	Discount Factor	Utility	VOS
	($/kW-yr)	(p.u.)	(kW)	($/kWh)	($/kWh)	(kWh)	($)	($)		($)	($)
2014	$86	1.000	1.000	$0.048	$0.048	1800	$86	$87	1.000	$86	$87
2015	$86	0.999	0.995	$0.048	$0.048	1791	$85	$86	0.926	$79	$80
2016	$86	0.998	0.990	$0.048	$0.048	1782	$85	$86	0.857	$73	$73
2017	$86	0.997	0.985	$0.048	$0.048	1773	$85	$85	0.794	$67	$68
2018	$86	0.996	0.980	$0.048	$0.048	1764	$84	$85	0.735	$62	$62
2019	$86	0.995	0.975	$0.048	$0.048	1755	$84	$84	0.681	$57	$57
2020	$86	0.994	0.970	$0.048	$0.048	1747	$84	$84	0.630	$53	$53
2021	$86	0.993	0.966	$0.048	$0.048	1738	$83	$84	0.583	$49	$49
2022	$86	0.992	0.961	$0.048	$0.048	1729	$83	$83	0.540	$45	$45
2023	$86	0.991	0.956	$0.048	$0.048	1721	$83	$83	0.500	$41	$41
2024	$86	0.990	0.951	$0.048	$0.048	1712	$82	$82	0.463	$38	$38
2025	$86	0.989	0.946	$0.048	$0.048	1703	$82	$82	0.429	$35	$35
2026	$86	0.988	0.942	$0.048	$0.048	1695	$82	$81	0.397	$32	$32
2027	$86	0.987	0.937	$0.048	$0.048	1686	$81	$81	0.368	$30	$30
2028	$86	0.986	0.932	$0.048	$0.048	1678	$81	$81	0.340	$28	$27
2029	$86	0.985	0.928	$0.048	$0.048	1670	$81	$80	0.315	$25	$25
2030	$86	0.984	0.923	$0.048	$0.048	1661	$80	$80	0.292	$23	$23
2031	$86	0.983	0.918	$0.049	$0.048	1653	$80	$79	0.270	$22	$21
2032	$86	0.982	0.914	$0.049	$0.048	1645	$80	$79	0.250	$20	$20
2033	$86	0.981	0.909	$0.049	$0.048	1636	$80	$79	0.232	$18	$18
2034	$86	0.980	0.905	$0.049	$0.048	1628	$79	$78	0.215	$17	$17
2035	$86	0.979	0.900	$0.049	$0.048	1620	$79	$78	0.199	$16	$15
2036	$86	0.978	0.896	$0.049	$0.048	1612	$79	$77	0.184	$14	$14
2037	$86	0.977	0.891	$0.049	$0.048	1604	$78	$77	0.170	$13	$13
2038	$86	0.976	0.887	$0.049	$0.048	1596	$78	$77	0.158	$12	$12
							Validation: Present Value			**$958**	**$958**

Avoided Reserve Capacity Cost

An example of the calculation of avoided reserve capacity cost is shown in Table 12. This is identical to the generation capacity cost calculation, except utility costs are multiplied by the reserve capacity margin. In the example, the reserve capacity margin is 15%, so the utility cost for 2014 is calculated as $86 per unit effective capacity x 15% = $13. The rest of the calculation is identical to the capacity cost calculation.

Avoided Transmission Capacity Cost

Avoided transmission costs are calculated the same way as avoided generation costs except in two ways. First, transmission capacity is assumed not to degrade over time (PV degradation is still accounted for). Second, avoided transmission capacity costs are calculated based on the utility’s 5-year average MISO OATT Schedule 9 charge in Start Year USD, e.g., in 2014 USD if year one of the VOS tariff was 2014. Table 13 shows the example calculation.

Table 12. (EXAMPLE) Economic value of avoided reserve capacity cost.

Year	Capacity Cost	Gen. Capacity	PV Capacity	Prices		p.u. PV Production	Costs		Discount Factor	Disc. Costs	
				Utility	VOS		Utility	VOS		Utility	VOS
	($/kW-yr)	(p.u.)	(kW)	($/kWh)	($/kWh)	(kWh)	($)	($)		($)	($)
2014	$86	1.000	1.000	$0.007	$0.007	1800	$13	$13	1.000	$13	$13
2015	$86	0.999	0.999	$0.007	$0.007	1791	$13	$13	0.926	$12	$12
2016	$86	0.998	0.994	$0.007	$0.007	1782	$13	$13	0.857	$11	$11
2017	$86	0.997	0.986	$0.007	$0.007	1773	$13	$13	0.794	$10	$10
2018	$86	0.996	0.971	$0.007	$0.007	1764	$13	$13	0.735	$9	$9
2019	$86	0.995	0.951	$0.007	$0.007	1755	$13	$13	0.681	$9	$9
2020	$86	0.994	0.927	$0.007	$0.007	1747	$13	$13	0.630	$8	$8
2021	$86	0.993	0.899	$0.007	$0.007	1738	$13	$13	0.583	$7	$7
2022	$86	0.992	0.872	$0.007	$0.007	1729	$12	$12	0.540	$7	$7
2023	$86	0.991	0.842	$0.007	$0.007	1721	$12	$12	0.500	$6	$6
2024	$86	0.990	0.809	$0.007	$0.007	1712	$12	$12	0.463	$6	$6
2025	$86	0.989	0.786	$0.007	$0.007	1703	$12	$12	0.429	$5	$5
2026	$86	0.988	0.762	$0.007	$0.007	1695	$12	$12	0.397	$5	$5
2027	$86	0.987	0.737	$0.007	$0.007	1686	$12	$12	0.368	$4	$4
2028	$86	0.986	0.713	$0.007	$0.007	1678	$12	$12	0.340	$4	$4
2029	$86	0.985	0.688	$0.007	$0.007	1670	$12	$12	0.315	$4	$4
2030	$86	0.984	0.663	$0.007	$0.007	1661	$12	$12	0.292	$4	$3
2031	$86	0.983	0.637	$0.007	$0.007	1653	$12	$12	0.270	$3	$3
2032	$86	0.982	0.612	$0.007	$0.007	1645	$12	$12	0.250	$3	$3
2033	$86	0.981	0.587	$0.007	$0.007	1636	$12	$12	0.232	$3	$3
2034	$86	0.980	0.563	$0.007	$0.007	1628	$12	$12	0.215	$3	$3
2035	$86	0.979	0.543	$0.007	$0.007	1620	$12	$12	0.199	$2	$2
2036	$86	0.978	0.523	$0.007	$0.007	1612	$12	$12	0.184	$2	$2
2037	$86	0.977	0.504	$0.007	$0.007	1604	$12	$12	0.170	$2	$2
2038	$86	0.976	0.485	$0.007	$0.007	1596	$12	$12	0.158	$2	$2
							Validation: Present Value			**$144**	**$144**

Table 13. (EXAMPLE) Economic value of avoided transmission capacity cost.

Year	Capacity Cost ($/kW-yr)	Trans. Capacity (p.u.)	PV Capacity (kW)	Prices: Utility ($/kWh)	Prices: VOS ($/kWh)	p.u. PV Production (kWh)	Costs: Utility ($)	Costs: VOS ($)	Discount Factor	Disc. Costs: Utility ($)	Disc. Costs: VOS ($)
2014	$33	1.000	1.000	$0.018	$0.018	1800	$33	$33	1.000	$33	$33
2015	$33	1.000	0.995	$0.018	$0.018	1791	$33	$33	0.926	$30	$30
2016	$33	1.000	0.990	$0.018	$0.018	1782	$33	$33	0.857	$28	$28
2017	$33	1.000	0.985	$0.018	$0.018	1773	$33	$33	0.794	$26	$26
2018	$33	1.000	0.980	$0.018	$0.018	1764	$32	$32	0.735	$24	$24
2019	$33	1.000	0.975	$0.018	$0.018	1755	$32	$32	0.681	$22	$22
2020	$33	1.000	0.970	$0.018	$0.018	1747	$32	$32	0.630	$20	$20
2021	$33	1.000	0.966	$0.018	$0.018	1738	$32	$32	0.583	$19	$19
2022	$33	1.000	0.961	$0.018	$0.018	1729	$32	$32	0.540	$17	$17
2023	$33	1.000	0.956	$0.018	$0.018	1721	$32	$32	0.500	$16	$16
2024	$33	1.000	0.951	$0.018	$0.018	1712	$31	$31	0.463	$15	$15
2025	$33	1.000	0.946	$0.018	$0.018	1703	$31	$31	0.429	$13	$13
2026	$33	1.000	0.942	$0.018	$0.018	1695	$31	$31	0.397	$12	$12
2027	$33	1.000	0.937	$0.018	$0.018	1686	$31	$31	0.368	$11	$11
2028	$33	1.000	0.932	$0.018	$0.018	1678	$31	$31	0.340	$10	$10
2029	$33	1.000	0.928	$0.018	$0.018	1670	$31	$31	0.315	$10	$10
2030	$33	1.000	0.923	$0.018	$0.018	1661	$30	$30	0.292	$9	$9
2031	$33	1.000	0.918	$0.018	$0.018	1653	$30	$30	0.270	$8	$8
2032	$33	1.000	0.914	$0.018	$0.018	1645	$30	$30	0.250	$8	$8
2033	$33	1.000	0.909	$0.018	$0.018	1636	$30	$30	0.232	$7	$7
2034	$33	1.000	0.905	$0.018	$0.018	1628	$30	$30	0.215	$6	$6
2035	$33	1.000	0.900	$0.018	$0.018	1620	$30	$30	0.199	$6	$6
2036	$33	1.000	0.896	$0.018	$0.018	1612	$30	$30	0.184	$5	$5
2037	$33	1.000	0.891	$0.018	$0.018	1604	$29	$29	0.170	$5	$5
2038	$33	1.000	0.887	$0.018	$0.018	1596	$29	$29	0.158	$5	$5
							Validation: Present Value			**$365**	**$365**

Avoided Distribution Capacity Cost

Avoided distribution capacity costs may be calculated in either of two ways:

- **System-wide Avoided Costs**. These are calculated using utility-wide costs and lead to a VOS rate that is "averaged" and applicable to all solar customers. This method is described below in the methodology.

- **Location-specific Avoided Costs**. These are calculated using location-specific costs, growth rates, etc., and lead to location-specific VOS rates. This method provides the utility with a means for offering a higher-value VOS rate in areas where capacity is most needed (areas of highest value). The details of this method are site specific and not included in the methodology, however they are to be implemented in accordance with the requirements set for the below.

System-wide Avoided Costs

System wide costs are determined using actual data from each of the last 10 years and peak growth rates are based on the utility's estimated future growth over the next 15 years. The costs and growth rate must be taken over the same time period because the historical investments must be tied to the growth associated with those investments.

All costs for each year for FERC accounts 360, 361, 362, 365, 366, and 367 should be included. These costs, however, should be adjusted to consider only capacity-related amounts. As such, the capacity-related percentages shown in Table 14 will be utility specific.

Table 14. (EXAMPLE) Determination of deferrable costs.

Account	Account Name	Additions ($) [A]	Retirements ($) [R]	Net Additions ($) = [A] - [R]	Capacity Related?	Deferrable ($)
	DISTRIBUTION PLANT					
360	Land and Land Rights	13,931,928	233,588	13,698,340	100%	13,698,340
361	Structures and Improvements	35,910,551	279,744	35,630,807	100%	35,630,807
362	Station Equipment	478,389,052	20,808,913	457,580,139	100%	457,580,139
363	Storage Battery Equipment					
364	Poles, Towers, and Fixtures	310,476,864	9,489,470	300,987,394		
365	Overhead Conductors and Devices	349,818,997	22,090,380	327,728,617	25%	81,932,154
366	Underground Conduit	210,115,953	10,512,018	199,603,935	25%	49,900,984
367	Underground Conductors and Devices	902,527,963	32,232,966	870,294,997	25%	217,573,749
368	Line Transformers	389,984,149	19,941,075	370,043,074		
369	Services	267,451,206	5,014,559	262,436,647		
370	Meters	118,461,196	4,371,827	114,089,369		
371	Installations on Customer Premises	22,705,193		22,705,193		
372	Leased Property on Customer Premises					
373	Street Lighting and Signal Systems	53,413,993	3,022,447	50,391,546		
374	Asset Retirement Costs for Distribution Plant	15,474,098	2,432,400	13,041,698		
TOTAL		3,168,661,143	130,429,387	3,038,231,756		**$856,316,173**

Cost per unit growth ($ per kW) is calculated by taking all of the total deferrable cost for each year, adjusting for inflation, and dividing by the kW increase in peak annual load over the 10 years.

Future growth in peak load is based on the utility's estimated future growth over the next 15 years. It is calculated using the ratio of peak loads of the fifteenth year (year 15) and the peak load from the first year (year 1):

$$GrowthRate = \left(\frac{P_{15}}{P_1}\right)^{1/14} - 1 \qquad (18)$$

If the resulting growth rate is zero or negative (before adding solar PV), set the avoided distribution capacity to zero.

A sample economic value calculation is presented in Table 15. The distribution cost for the first year ($200 per kW in the example) is taken from the analysis of historical cost and estimated growth as described above. This cost is escalated each year using the rate in the VOS Data Table.

For each future year, the amount of new distribution capacity is calculated based on the growth rate, and this is multiplied by the cost per kW to get the cost for the year. The total discounted cost is calculated ($149M) and amortized over the 25 years.

PV is assumed to be installed in sufficient capacity to allow this investment stream to be deferred for one year. The total discounted cost of the deferred time series is calculated ($140M) and amortized.

Utility costs are calculated using the difference between the amortized costs of the conventional plan and the amortized cost of the deferred plan. For example, the utility cost for 2022 is ($14M - $13M)/54MW x 1000 W/kW = $14 per effective kW of PV. As before, utility prices are back-calculated using PV production, and the VOS component rate is calculated such that the total discounted amount equals the discounted utility cost.

Location-specific Avoided Costs

As an alternative to system-wide costs for distribution, location-specific costs may be used. When calculating location-specific costs, the calculation should follow the same method of the system-wide avoided cost method, but use local technical and cost data. The calculation should satisfy the following requirements:

- The distribution cost VOS should be calculated for each distribution planning area, defined as the minimum area in which capacity needs cannot be met by transferring loads internally from one circuit to another.
- Distribution loads (the sum of all relevant feeders), peak load growth rates and capital costs should be based on the distribution planning area.

- Local Fleet Production Shapes may be used, if desired. Alternatively, the system-level Fleet Production Shape may be used.
- Anticipated capital costs should be evaluated based on capacity related investments only (as above) using budgetary engineering cost estimates. All anticipated capital investments in the planning area should be included. Planned capital investments should be assumed to meet capacity requirements for the number of years defined by the amount of new capacity added (in MW) divided by the local growth rate (MW per year). Beyond this time period, which is beyond the planning horizon, new capacity investments should be assumed each year using the system-wide method.
- Planning areas for which engineering cost estimates are not available may be combined, and the VOS calculated using the system-wide method.

Table 15. (EXAMPLE) Economic value of avoided distribution capacity cost, system-wide.

		Conventional Distribution Planning				Deferred Distribution Planning			
Year	Distribution Cost	New Dist. Capacity	Capital Cost	Disc. Capital Cost	Amortized	Def. Dist. Capacity	Def. Capital Cost	Disc. Capital Cost	Amortized
	($/kW)	(MW)	($M)	($M)	$M/yr	(MW)	($M)	($M)	$M/yr
2014	$200	50	$10	$10	$14				$13
2015	$204	50	$10	$9	$14	50	$10	$9	$13
2016	$208	51	$11	$9	$14	50	$10	$9	$13
2017	$212	51	$11	$9	$14	51	$11	$9	$13
2018	$216	52	$11	$8	$14	51	$11	$8	$13
2019	$221	52	$11	$8	$14	52	$11	$8	$13
2020	$225	53	$12	$7	$14	52	$12	$7	$13
2021	$230	53	$12	$7	$14	53	$12	$7	$13
2022	$234	54	$13	$7	$14	53	$12	$7	$13
2023	$239	54	$13	$6	$14	54	$13	$6	$13
2024	$244	55	$13	$6	$14	54	$13	$6	$13
2025	$249	55	$14	$6	$14	55	$14	$6	$13
2026	$254	56	$14	$6	$14	55	$14	$6	$13
2027	$259	56	$15	$5	$14	56	$14	$5	$13
2028	$264	57	$15	$5	$14	56	$15	$5	$13
2029	$269	57	$15	$5	$14	57	$15	$5	$13
2030	$275	58	$16	$5	$14	57	$16	$5	$13
2031	$280	59	$16	$4	$14	58	$16	$4	$13
2032	$286	59	$17	$4	$14	59	$17	$4	$13
2033	$291	60	$17	$4	$14	59	$17	$4	$13
2034	$297	60	$18	$4	$14	60	$18	$4	$13
2035	$303	61	$18	$4	$14	60	$18	$4	$13
2036	$309	62	$19	$4	$14	61	$19	$3	$13
2037	$315	62	$20	$3	$14	62	$19	$3	$13
2038	$322	63	$20	$3	$14	62	$20	$3	$13
2039	$328					63	$21	$3	
				$149				$140	

CONTINUED Table 15. (EXAMPLE) Economic value of avoided distribution capacity cost, system-wide.

Year	p.u. PV Production	Costs		Discount Factor	Disc. Costs		Prices	
		Utility	**VOS**		**Utility**	**VOS**	**Utility**	**VOS**
	(kWh)	($)	($)		($)	($)	($/kWh)	($/kWh)
2014	1800	$16	$15	1.000	$16	$15	$0.009	$0.008
2015	1791	$15	$15	0.926	$14	$14	$0.009	$0.008
2016	1782	$15	$15	0.857	$13	$13	$0.009	$0.008
2017	1773	$15	$15	0.794	$12	$12	$0.009	$0.008
2018	1764	$15	$15	0.735	$11	$11	$0.009	$0.008
2019	1755	$15	$15	0.681	$10	$10	$0.008	$0.008
2020	1747	$15	$15	0.630	$9	$9	$0.008	$0.008
2021	1738	$15	$15	0.583	$9	$8	$0.008	$0.008
2022	1729	$14	$14	0.540	$8	$8	$0.008	$0.008
2023	1721	$14	$14	0.500	$7	$7	$0.008	$0.008
2024	1712	$14	$14	0.463	$7	$7	$0.008	$0.008
2025	1703	$14	$14	0.429	$6	$6	$0.008	$0.008
2026	1695	$14	$14	0.397	$6	$6	$0.008	$0.008
2027	1686	$14	$14	0.368	$5	$5	$0.008	$0.008
2028	1678	$14	$14	0.340	$5	$5	$0.008	$0.008
2029	1670	$13	$14	0.315	$4	$4	$0.008	$0.008
2030	1661	$13	$14	0.292	$4	$4	$0.008	$0.008
2031	1653	$13	$14	0.270	$4	$4	$0.008	$0.008
2032	1645	$13	$14	0.250	$3	$3	$0.008	$0.008
2033	1636	$13	$14	0.232	$3	$3	$0.008	$0.008
2034	1628	$13	$14	0.215	$3	$3	$0.008	$0.008
2035	1620	$13	$14	0.199	$3	$3	$0.008	$0.008
2036	1612	$13	$13	0.184	$2	$2	$0.008	$0.008
2037	1604	$12	$13	0.170	$2	$2	$0.008	$0.008
2038	1596	$12	$13	0.158	$2	$2	$0.008	$0.008
2039								

Validation: Present Value	$166	$166

Avoided Environmental Cost

Environmental costs are included as a required component and are based on existing Minnesota and federal externality costs. CO_2 and non-CO_2 natural gas emissions factors (lb per MM BTU of natural gas) are from the EPA[17]and NaturalGas.org.[18] Avoided environmental costs are based on the federal social cost of CO_2 emissions[19] plus the Minnesota PUC-established externality costs for non-CO_2 emissions.[20]

The externality cost of CO_2 emissions shown in Table 4 are calculated as follows. The Social Cost of Carbon (CO_2) values for each year through 2050 are published in 2007 dollars per metric ton.[21] These costs are adjusted for inflation (converted to current dollars), converted to dollars per short ton, and then converted to cost per unit fuel consumption using the assumed values in Table 16.

For example, the CO_2 externality cost for 2020 (3.0% discount rate, average) is $43 per metric ton of CO_2 emissions in 2007 dollars. This is converted to current dollars by multiplying by a CPI adjustment factor; for 2014, the CPI adjustment factor is of 1.13.[22] The resulting CO_2 costs per metric ton in current dollars are then converted to dollars per short ton by dividing by 1.102. Finally, the costs are escalated using the general escalation rate of 2.75% per year to give $54.76 per ton. The $54.76 per ton of CO_2 is then divided by 2000 pounds per ton and multiplied by 117.0 pounds of CO_2 per MMBtu = $3.204 per MMBtu in 2020 dollars.

Table 16. Natural Gas Emissions.

	NG Emissions (lb/MMBtu)
PM_{10}	0.007
CO	0.04
NO_X	0.092
Pb	0.00
CO_2	117.0

[17] http://www.epa.gov/climatechange/ghgemissions/ind-assumptions.html and http://www.epa.gov/ttnchie1/ap42/
[18] http://www.naturalgas.org/environment/naturalgas.asp
[19] See http://www.epa.gov/climatechange/EPAactivities/economics/scc.html, technical support document appendix, May 2013.
[20] "Notice of Updated Environmental Externality Values," issued June 5, 2013, PUC docket numbers E-999/CI-93-583 and E-999/CI-00-1636.
[21] The annual Social Cost of Carbon values are listed in table A1 of the Social Cost of Carbon Technical Support Document. The Technical Support Document can be found at: http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf.
[22] The CPI adjustment factor can be calculated through the Bureau of Labor Statistics CPI inflation calculator. The calculator can be found at: http://data.bls.gov/cgi-bin/cpicalc.pl.

Pollutants other than CO_2 are calculated using the Minnesota externality costs using the following method. Externality costs are calculated as the midpoint of the low and high values for the urban scenario, adjusted to current dollars, and converted to a fuel-based value using Table 16. Each utility may select the set of non-CO_2 externality values that is most appropriate for their service territory (e.g. urban or metropolitan fringe or rural).

For the example, MN PUC's published 2012 urban externality values for PM10 are $6,291 per ton (low case) and $9,056 per ton (high case). These are averaged to be ($6291+$9056)/2 = $7674 per ton of PM10 emissions. For 2020, these are escalated using the general escalation rate of 2.75% per year to $9,533 per ton. The $9,533 per ton of PM10 is then divided by 2000 pounds per ton and multiplied by 0.007 pounds of PM10 per MMBtu to arrive at a PM10 externality cost of $0.033 per MMBtu. Similar calculations are done for the other pollutants.

In the example shown in Table 17, the environmental cost is the sum of the costs of all pollutants. For example, in 2020, the total cost of $3.287 per MMBtu corresponds to the 2020 total cost in Table 4. This cost is multiplied by the heat rate for the year (see Avoided Fuel Cost calculation) and divided by 10^6 (to convert Btus to MMBtus), which results in the environmental cost in dollars per kWh for each year. The remainder of the calculation follows the same method as the avoided variable O&M costs but using the environmental discount factor (see Discount Factors for a description of the environmental discount factor and its calculation).

Avoided Voltage Control Cost

This is reserved for future updates to the methodology.

Solar Integration Cost

This is reserved for future updates to the methodology.

Table 17. (EXAMPLE) Economic value of avoided environmental cost.

Year	Env. Cost ($/MMBtu)	Heat Rate (Btu/kWh)	Prices Utility ($/kWh)	Prices VOS ($/kWh)	p.u. PV Production (kWh)	Costs Utility ($)	Costs VOS ($)	Discount Factor	Disc. Costs Utility ($)	Disc. Costs VOS ($)
2014	2.022	8000	$0.016	$0.027	1,800	$29	$48	1.000	$29	$48
2015	2.131	8008	$0.017	$0.027	1,791	$31	$48	0.945	$29	$45
2016	2.245	8016	$0.018	$0.027	1,782	$32	$47	0.893	$29	$42
2017	2.363	8024	$0.019	$0.027	1,773	$34	$47	0.844	$28	$40
2018	2.487	8032	$0.020	$0.027	1,764	$35	$47	0.797	$28	$37
2019	2.615	8040	$0.021	$0.027	1,755	$37	$47	0.753	$28	$35
2020	2.749	8048	$0.022	$0.027	1,747	$39	$46	0.712	$28	$33
2021	2.888	8056	$0.023	$0.027	1,738	$40	$46	0.673	$27	$31
2022	3.032	8064	$0.024	$0.027	1,729	$42	$46	0.636	$27	$29
2023	3.182	8072	$0.026	$0.027	1,721	$44	$46	0.601	$27	$27
2024	3.338	8080	$0.027	$0.027	1,712	$46	$46	0.567	$26	$26
2025	3.501	8088	$0.028	$0.027	1,703	$48	$45	0.536	$26	$24
2026	3.669	8097	$0.030	$0.027	1,695	$50	$45	0.507	$26	$23
2027	3.770	8105	$0.031	$0.027	1,686	$52	$45	0.479	$25	$21
2028	3.950	8113	$0.032	$0.027	1,678	$54	$45	0.452	$24	$20
2029	4.138	8121	$0.034	$0.027	1,670	$56	$44	0.427	$24	$19
2030	4.332	8129	$0.035	$0.027	1,661	$59	$44	0.404	$24	$18
2031	4.534	8137	$0.037	$0.027	1,653	$61	$44	0.382	$23	$17
2032	4.744	8145	$0.039	$0.027	1,645	$64	$44	0.361	$23	$16
2033	4.962	8153	$0.040	$0.027	1,636	$66	$44	0.341	$23	$15
2034	5.189	8162	$0.042	$0.027	1,628	$69	$43	0.322	$22	$14
2035	5.424	8170	$0.044	$0.027	1,620	$72	$43	0.304	$22	$13
2036	5.668	8178	$0.046	$0.027	1,612	$75	$43	0.287	$21	$12
2037	5.922	8186	$0.048	$0.027	1,604	$78	$43	0.272	$21	$12
2038	6.185	8194	$0.051	$0.027	1,596	$81	$42	0.257	$21	$11
						Validation: Present Value			**$629**	**$629**

VOS Example Calculation

The gross economic value, load match, distributed loss savings factor, and distributed PV value are combined in the required VOS Levelized Calculation Chart. An example is presented in Figure 2 using the assumptions made for the example calculation. Actual VOS results will differ from those shown in the example, but utilities will include in their application a VOS Levelized Calculation Chart in the same format. For completeness, Figure 3 (not required of the utilities) is presented showing graphically the relative importance of the components in the example.

Figure 3. (EXAMPLE) VOS Levelized Calculation Chart (Required).

25 Year Levelized Value	Economic Value ($/kWh)	Load Match (No Losses) (%)	Distributed Loss Savings (%)	Distributed PV Value ($/kWh)
Avoided Fuel Cost	$0.056		8%	$0.061
Avoided Plant O&M - Fixed	$0.003	40%	9%	$0.001
Avoided Plant O&M - Variable	$0.001		8%	$0.001
Avoided Gen Capacity Cost	$0.048	40%	9%	$0.021
Avoided Reserve Capacity Cost	$0.007	40%	9%	$0.003
Avoided Trans. Capacity Cost	$0.018	40%	9%	$0.008
Avoided Dist. Capacity Cost	$0.008	30%	5%	$0.003
Avoided Environmental Cost	$0.027		8%	$0.029
Avoided Voltage Control Cost				
Solar Integration Cost				
				$0.127

Having calculated the levelized VOS credit, an inflation-adjusted VOS can then be found. An EXAMPLE inflation-adjusted VOS is provided in Figure 5 by using the general escalation rate as the annual inflation rate for all years of the analysis period. Both the inflation-adjusted VOS and the levelized VOS in Figure 5 represent the same long-term value. The methodology requires that the inflation-adjusted (real) VOS be used and updated annually to account for the current year's inflation rate.

To calculate the inflation-adjusted VOS for the first year, the products of the levelized VOS, PV production and the discount factor are summed for each year of the analysis period and then divided by the sum of the products of the escalation factor, PV production, and the discount factor for each year of the analysis period, as shown below in Equation (17).

Figure 4. (EXAMPLE) Levelized value components.

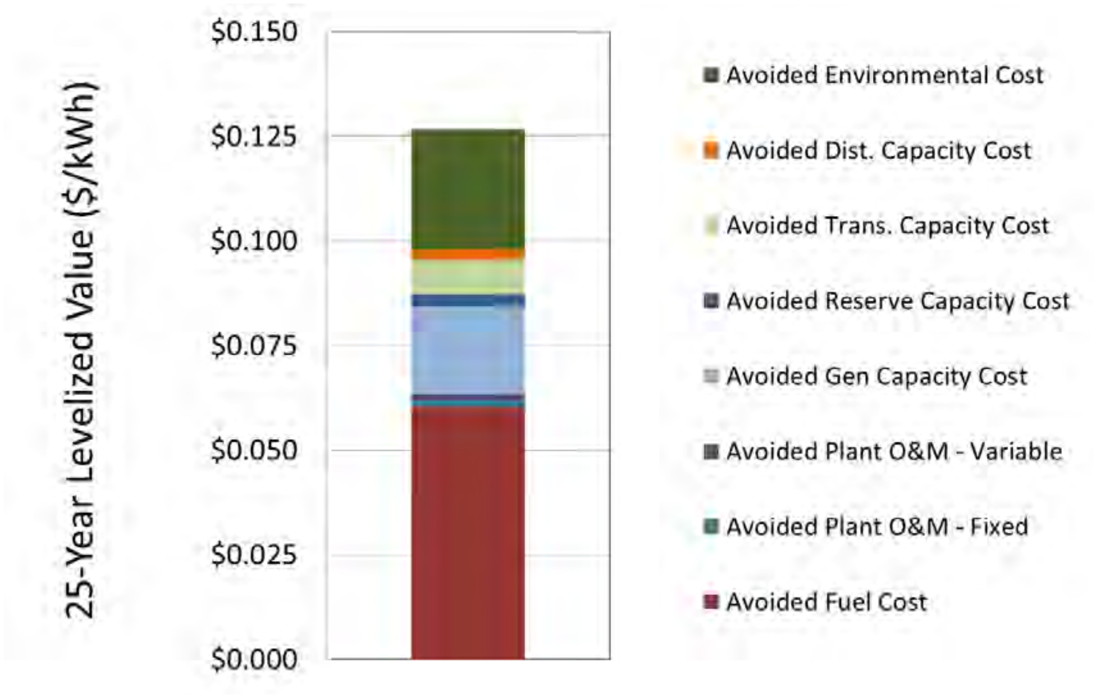
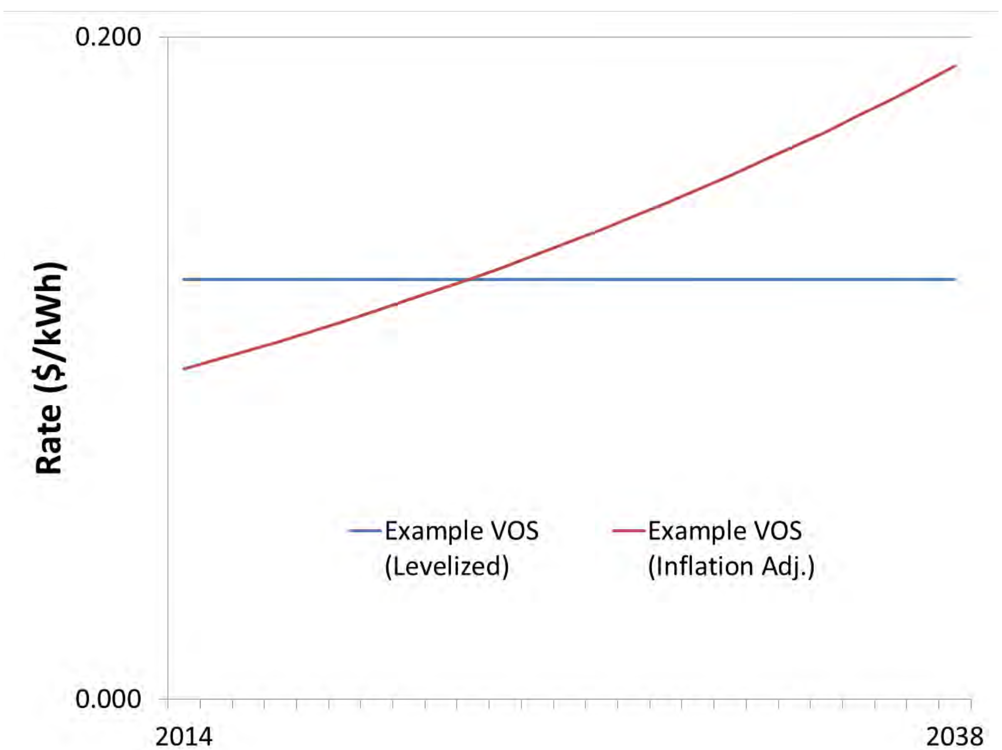


Figure5. (EXAMPLE) Inflation-Adjusted VOS.



$$InflationAdjustedVOS_{Year0}\left(\frac{\$}{kWh}\right) \tag{19}$$

$$= \frac{\sum_i LevelizedVOS \times PVProduction_i \times DiscountFactor_i}{\sum_i EscalationFactor_i \times PVProduction_i \times DiscountFactor_i}$$

Once the first-year inflation-adjusted VOS is calculated, the value will then be updated on an annual basis in accordance with the observed inflation-rate. Table 18 provides the calculation of the EXAMPLE inflation-adjusted VOS shown in Figure 5. In this EXAMPLE, the inflation rate in future years is set equal to the general escalation rate of 2.75%.

Table 18. (EXAMPLE) Calculation of inflation-adjusted VOS.

Year	Discount Factor	Escalation Factor	Example VOS (Levelized)	Disc.	Example VOS (Inflation Adj.)	Disc.
2014	1.000	1.000	0.127	0.127	0.100	0.100
2015	0.926	1.027	0.127	0.117	0.102	0.095
2016	0.857	1.056	0.127	0.109	0.105	0.090
2017	0.794	1.085	0.127	0.101	0.108	0.086
2018	0.735	1.115	0.127	0.093	0.111	0.082
2019	0.681	1.145	0.127	0.086	0.114	0.078
2020	0.630	1.177	0.127	0.080	0.117	0.074
2021	0.583	1.209	0.127	0.074	0.121	0.070
2022	0.540	1.242	0.127	0.068	0.124	0.067
2023	0.500	1.276	0.127	0.063	0.127	0.064
2024	0.463	1.311	0.127	0.059	0.131	0.061
2025	0.429	1.347	0.127	0.054	0.134	0.058
2026	0.397	1.384	0.127	0.050	0.138	0.055
2027	0.368	1.422	0.127	0.047	0.142	0.052
2028	0.340	1.462	0.127	0.043	0.146	0.050
2029	0.315	1.502	0.127	0.040	0.150	0.047
2030	0.292	1.543	0.127	0.037	0.154	0.045
2031	0.270	1.585	0.127	0.034	0.158	0.043
2032	0.250	1.629	0.127	0.032	0.162	0.041
2033	0.232	1.674	0.127	0.029	0.167	0.039
2034	0.215	1.720	0.127	0.027	0.172	0.037
2035	0.199	1.767	0.127	0.025	0.176	0.035
2036	0.184	1.815	0.127	0.023	0.181	0.033
2037	0.170	1.865	0.127	0.022	0.186	0.032
2038	0.158	1.917	0.127	0.020	0.191	0.030
				1.461		1.461

Glossary

Table 19. Input data definitions

Input Data	Used in Methodology Section	Definition
Annual Energy	PV Energy Production	The annual PV production (kWh per year) per Marginal PV Resource (initially 1 kW-AC) in the first year (before any PV degradation) of the marginal PV resource. This is calculated in the Annual Energy section of PV Energy Production and used in the Equipment Degradation section.
Capacity-related distribution capital cost	Avoided Distribution Capacity Cost	This is described more fully in the Avoided Distribution Capacity Cost section.
Capacity-related transmission capital cost	Avoided Transmission Capacity Cost	The cost per kW of new construction of transmission, including lines, towers, insulators, transmission substations, etc. Only capacity-related costs should be included.
Discount rate (WACC)	Multiple	The utility's weighted average cost of capital, including interest on bonds and shareholder return.
Distribution capital cost escalation	Avoided Distribution Capacity Cost	Used to calculate future distribution costs.
ELCC (no loss), PLR (no loss)	Load Match Factors	The "Effective Load Carrying Capability" and the "Peak Load Reduction" of a PV resource expressed as percentages of rated capacity (kW-AC). These are described more fully in the Load Match section.
Environmental Costs	Avoided Environmental Cost	The costs required to calculate environmental impacts of conventional generation. These are described more fully in the Avoided Environmental Cost section

Input Data	Used in Methodology Section	Definition
Environmental Discount Rate	Avoided Environmental Cost	The societal discount rate used to calculate the present value of future environmental costs.
Fuel Price Overhead	Avoided Fuel Cost	The difference in cost of fuel as delivered to the plant and the cost of fuel as available in market prices. This cost reflects transmission, delivery, and taxes.
General escalation rate	Avoided Environmental Cost, Example Results	The annual escalation rate corresponding to the most recent 25 years of CPI index data[23], used to convert constant dollar environmental costs into current dollars and to translate levelized VOS into inflation-adjusted VOS.
Generation Capacity Degradation	Avoided Generation Capacity Cost	The percentage decrease in the generation capacity per year
Generation Life	Avoided Generation Capacity Cost	The assumed service life of new generation assets.
Guaranteed NG Fuel Prices	Avoided Fuel Cost	The annual average prices to be used when the utility elects to use the Futures Market option. These are not applicable when the utility elects to use options other than the Futures Market option. They are calculated as the annual average of monthly NYMEX NG futures[24].
Heat rate degradation	Avoided Generation Capacity Cost	The percentage increase in the heat rate (BTU per kWh) per year

[23] www.bls.gov.

[24] See for example http://futures.tradingcharts.com/marketquotes/NG.html.

Input Data	Used in Methodology Section	Definition
Installed cost and heat rate for CT and CCGT	Avoided Generation Capacity Cost	The capital costs for these units (including all construction costs, land, ad valorem taxes, etc.) and their heat rates.
Loss Savings (Energy, PLR, and ELCC)	Loss Savings Analysis	The additional savings associated with Energy, PRL and ELCC, expressed as a percentage. These are described more fully in the Loss Savings section.
O&M cost escalation rate	Avoided Plant O&M – Fixed, Avoided Plant O&M – Variable	Used to calculate future O&M costs.
O&M fixed costs	Avoided Plant O&M – Fixed	The costs to operate and maintain the plant that are not dependent on the amount of energy generated.
O&M variable costs	Avoided Plant O&M – Variable	The costs to operate and maintain the plant (excluding fuel costs) that are dependent on the amount of energy generated.
Peak Load	Avoided Distribution Capacity Cost	The utility peak load as expected in the VOS start year.
Peak load growth rate	Avoided Distribution Capacity Cost	This is described more fully in the Avoided Distribution Capacity Cost section.
PV Degradation	Equipment Degradation Factors	The reduction in percent per year of PV capacity and PV energy due to degradation of the modules. The value of 0.5 percent is the median value of 2000 observed degradation rates.[25]

[25] D. Jordan and S. Kurtz, "Photovoltaic Degradation Rates – An Analytical Review," NREL, June 2012.

Input Data	Used in Methodology Section	Definition
PV Life	Multiple	The assumed service life of PV. This value is also used to define the study period for which avoided costs are determined and the period over which the VOS rate would apply.
Reserve planning margin	Avoided Reserve Capacity Cost	The planning margin required to ensure reliability.
Solar-weighted heat rate	Avoided Fuel Costs	This is described in the described in the Avoided Fuel Costs section.
Start Year for VOS applicability	Multiple	This is the first year in which the VOS would apply and the first year for which avoided costs are calculated.
Transmission capital cost escalation	Avoided Transmission Capacity Cost	Used to adjust costs for future capital investments.
Transmission life	Avoided Transmission Capacity Cost	The assumed service life of new transmission assets.
Treasury Yields	Escalation and Discount Rates	Yields for U.S. Treasuries, used as the basis of the risk-free discount rate calculation.[26]
Years until new transmission capacity is needed	Avoided Transmission Capacity Cost	This is used to test whether avoided costs for a given analysis year should be calculated and included.

[26] See http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

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Acronyms

Distributed Generation (DG)

Distributed Generation Photovoltaics (DGPV)

Distributed solar generation (DSG)

Distributed Solar Photovoltaics (DPV)

Investment Tax Credit (ITC)

Kilowatt (kW)

Kilowatt-hour (kWh)

Levelized Cost of Energy (LCOE)

Megawatt-hour (MWh)

Modified Accelerated Cost Recovery System (MACRS)

Net Energy Metering (NEM)

Operations and Maintenance (O&M)

Photovoltaics (PV)

Public Utilities Commission (PUC)

Public Utilities Regulatory Policies Act (PURPA)

Qualifying facility (QF)

Renewable Energy Certificate (REC)

Value of Solar (VOS)

Watt (W)

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Executive Summary

Distributed generation solar photovoltaic (DGPV) technology is being rapidly adopted in many areas of the United States, spurring jurisdictions to investigate the costs and benefits of grid-connected DGPV to the electricity system. The value of solar (VOS) is a relatively new mechanism for the purchase of distributed solar generation that is being considered in some locations. A VOS tariff is intended to be compensation for real value provided by the solar installations to the electric system.[1] This report is designed for utilities, regulators, and stakeholders who are interested in issues related to VOS program design and implementation. It discusses and addresses VOS program design options and considers how a VOS rate may impact future development of DGPV projects. The work herein does not consider the calculation of a VOS rate and does not address the cost of solar in relation to utility retail rates.

The degree to which DGPV is deployed within a jurisdiction is largely determined by the economic proposition facing the electricity customer. Distributed solar technology can be an economically interesting alternative if the levelized cost of energy (LCOE) at which solar can be deployed is lower than (or equal to) the electricity costs avoided by the customer (e.g., the price of purchasing generation from the utility at the retail electricity rate). Given current solar costs, some form of incentive is still required to make solar deployment economical for the average electricity customer in many locations. Over time, if solar costs continue to decline, the need for incentives is expected to diminish as solar generation becomes more price-competitive with retail electricity rates.

As the costs of solar continue to decline, the VOS mechanism is likely to gain increasing attention. A VOS rate is determined through a bottom-up calculation of each of the benefits and costs that distributed solar provides to or imposes on the electricity system. The values generally represent avoided costs to the utility and the overall system (e.g., avoided transmission and distribution (T&D) services) and the costs of incorporating solar into the system.[2] These value streams are added together to arrive at a single VOS rate, expressed in cents per kilowatt-hour (kWh). This is the rate at which customers are compensated for electricity generated by their grid-connected DGPV systems.[3]

The VOS mechanism is in the early stages of development and has been adopted in only two locations: Austin Energy (where it is in active use) and in the state of Minnesota (where it is under development). In both of these locations, the VOS mechanism is a "buy-all sell-all" transaction wherein customers purchase all of their electricity needs at the applicable retail rate and sell all of the solar production to the utility at the VOS rate being offered (typically through a bill credit). Another design option, which has not yet been implemented, is to pay the VOS rate

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[1] In this document, *VOS rate* and *VOS tariff* are used interchangeably to refer to the amount (number) that is being paid by the utility for solar generation by self-generating customers. The term *VOS mechanism* is used to refer to the policy or program in the broader sense.

[2] Few studies, to date, have included cost components in the calculation of the VOS rate. The analysis conducted for this report is based on the most commonly discussed value components and does not include the costs of solar to the electricity system.

[3] The goal of this report is not to estimate the VOS rate or "number" for any value component in any particular location. Research by NREL, Clean Power Research (CPR), Electric Power Research Institute (EPRI), Rocky Mountain Institute (RMI), and Interstate Renewable Energy Council (IREC) lays the foundation for performing VOS rate calculations; summaries of some existing VOS rate calculation research are presented in the Appendix A.

for only the net excess generation that is fed back to the utility (that is, to subtract out any generation that is consumed on-site).

The stakeholders in a VOS rate program have various interests and concerns, some shared and some individual. The utilities, regulators, and electricity customers all have an interest in the provision of reliable electric service that meets electricity demands into the future. Solar generation, being a local supply of power with no fuel cost, offers some future reliability benefit. Utilities will benefit from a VOS program that is straightforward to manage, a characteristic that can be considered during VOS program design. Utilities also may want to recover the costs of providing fixed-cost services (such as transmission and distribution) to their customers. A "buy-all, sell-all" VOS program design separates the utility's compensation for solar generation from the customer's purchase of retail electricity, which can allow for full recovery of utility fixed costs.

Policymakers have an interest in ensuring that the utility receives payment for the services that it provides and that cross-subsidies between solar and non-solar customers are minimized. They also may want to address increasing customer demand for distributed solar and to capture the associated environmental benefits. The DGPV owner is interested in having a long-term agreement to receive payment for solar generation that (at least) covers the cost of solar investment. The PV system generation purchaser/owner can benefit from the hedge that fixed-cost solar electricity can provide from future increases in retail rates. By being alert to the existing market for solar, and adding interim support mechanisms to the VOS rate, if necessary, policy makers can support continued solar develop and address customer interests.

The solar industry likely seeks an open, fair market for solar products and services, certainty in payments for solar generation, predictability in policy, and long-term assurance for its investors. All customers, and society at large, benefit from electricity generation that meets public policy goals for environmental protection and economic development at the lowest possible cost to the consumer. (Kind 2013; Keyes and Rábago 2013; Hansen, Lacy, and Glick 2013). By setting clear procedures and timelines for the application and update of VOS rates, program designers can ensure that the VOS program provides the predictability and risk reduction necessary to make solar projects attractive to investors, as well as financeable.

While there has been much discussion and debate across the country regarding the most effective or appropriate method to calculate the variety of benefits and costs associated with distributed solar, as well has how those could be monetized in a rate, very little broad-based analysis has been conducted on the design of a VOS program. This report describes the numerous program design options utilities face as they consider a VOS tariff offering.

When designing a VOS policy, several considerations can be evaluated. One of the first to consider is the market construct that impacts program design; three feasible market constructs include:

- **Price-support Market (LCOE-PV > VOS Tariff)**
    - VOS rate is not sufficient to recover the levelized-cost of DGPV installations
    - Additional incentives are likely needed to fill the difference between the VOS payments and the levelized cost of PV, in order to sustain the solar market

- **Transitional Market (LCOE-PV ≈ VOS Tariff)**
    - VOS rate is nearly equal to the levelized cost of PV installation
    - Few incentives are needed to sustain the solar market
    - VOS program design needs to reflect the shift toward equalization
- **Price-competitive Market (LCOE-PV ≤ VOS Tariff)**
    - VOS rate is higher than the levelized cost of PV installations
    - The solar market is self-sustaining and separate incentives are no longer needed.

Many factors drive the type of market that exists in a given region. For example, the strength of the solar resource, lower permitting or interconnection fees, and the presence of incentives can all drive down the LCOE-PV, while capacity needs, efficiency of the generation fleet, and environmental value may increase the value of solar generation to the electricity system. These factors change over time, so transitional markets can float between price-support and price-competitive, depending on circumstances.

Here, we present an analysis that assesses the potential market type that might form in the United States under a VOS rate, given current national average solar costs and various incentive scenarios, for the most populous city in each state. Three hypothetical VOS tariffs were developed, based on assumptions of avoided fuel costs, avoided capacity, environmental benefits, and line losses, to represent a of range of possible VOS rates. The levelized cost of solar in 50 locations is calculated using NREL's System Advisor Model (SAM) using input assumptions regarding system size, resource quality, avoided capacity (aka capacity factor) and a variety of incentives. Comparing the solar costs with the hypothetical VOS rates illustrates the various market types that may form under a VOS program, in different locations.

Based on the high-level analysis completed to support this report,[4] the implementation of a VOS rate in the ranges typically discussed today is unlikely to result in a price-competitive market in most locations. Even including the federal investment tax credit (ITC), a VOS rate at the generic levels assumed for the analysis do not appear to cover the levelized cost of solar deployment in most locations. The bars in Figure ES-1 indicate the range of solar markets that may manifest themselves in locations across the country, assuming different VOS rates and various combinations of incentives at the state and federal levels. The solar market is considered to be price-competitive only in locations and scenarios for which the results fall above the x-axis. Note that this chart does not include net energy metering (NEM) as it is assumed that the VOS tariff replaces NEM (this replacement of NEM with VOS is the dominant model under discussion in the market to date). Based on this generic, national analysis it appears that incentives, including the federal ITC, are likely to continue to play a critical role in deploying solar nationally in the near term, even where a VOS rate might be applied.

[4] This analysis did not include every possible solar value proposition. It relied on publicly available, published data sources. The analysis provides a general indication of a range of potential markets that could result based on the analysis assumptions. Each jurisdiction would need to do a more specific analysis for its situation to get a more exact understanding of that particular VOS tariff.

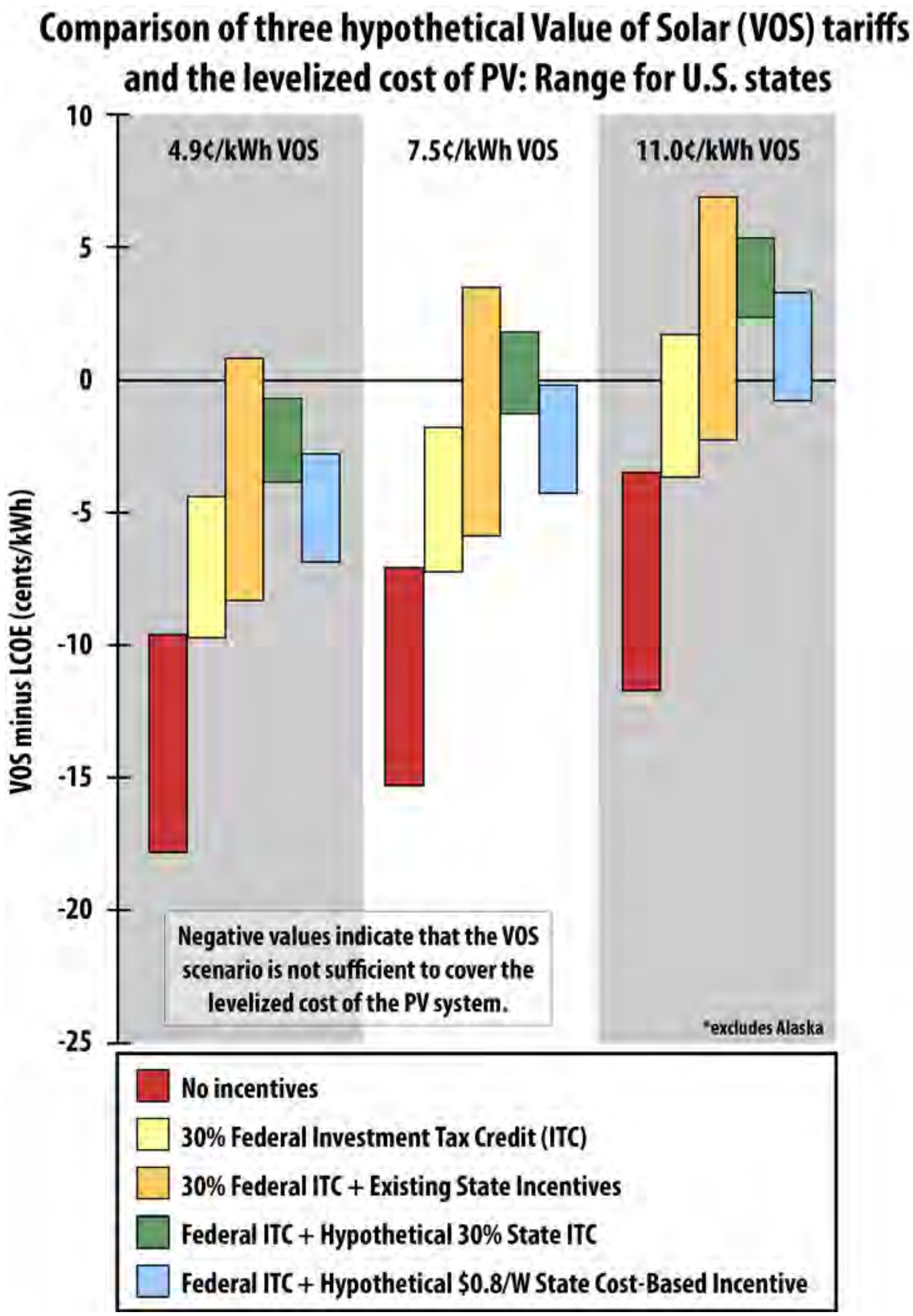

Figure ES-1. Comparison of VOS and LCOE-PV

Rate calculation methods and program design elements are important aspects for decision makers to evaluate when considering offering a VOS program. These two components are strongly linked and greatly influence the results of a VOS program. Within the realm of program design, the authors focus on four major program design areas, with a multitude of individual design considerations available under each:

1. Installation details
2. Rate options
3. Incentive options
4. Administrative issues.

VOS program design encompasses issues such as:

- The objectives and philosophy of the program design process
- Eligibility and installation rules and details for participation
- Rate and contract terms implemented for a long-term program
- Additional price supports needed to sustain continued PV development
- Stakeholder involvement in the VOS program development
- How program design components might change as the solar market changes.

Utilities can, to some extent, draw on experiences from managing other programs that support solar, including NEM and incentive programs, such as rebates. However, several areas are unique to the new market transaction structure that a VOS tariff represents. For these jurisdictions that have a combined goal of maintaining a robust solar market that is fair and equitable to all parties and that moves solar from a position of price-support to price-competitive, VOS programs will require sufficient design and implementation flexibility to ensure that market growth continues.

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1 Introduction

The distributed solar electricity market in the United States, most predominately represented by rooftop solar installations, has been growing rapidly for several years, with 7,853 MWdc of distributed solar installed by October 2014, representing nearly half of the total installed solar capacity in the U.S. (SEIA/GTM 2014). The amount and growth of distributed solar generation is spurring policy discussions across the United States around the costs and benefits of these systems.

Net energy metering (NEM) policies have been one important part of the foundation that has enabled the growth of distributed solar development in nearly all states. NEM allows a utility's solar customers to manage solar generation and electricity consumption mismatches over time, utilizing the electric grid as an accounting "bank" for excess solar kWh in one moment to be "withdrawn" for future consumption. However, rapid solar growth in some states has raised concerns about the sustainability of NEM at high DGPV penetrations to the utilities' long-term business health. Utilities may desire to recover the fixed costs of operating the electric grid by spreading the costs across all ratepayers. Even in states where solar is not yet an economical alternative and there are few installations, the future prospect of increased deployment is sparking discussion about alternative payment mechanisms. Key discussions have focused on several options, including keeping NEM as is, studying and reporting on the costs and benefits of solar, adding or increasing the fixed fee in solar customers' rates, adjusting recovery models within all customer rates, and (as is most germane to this paper) compensating solar generators at a rate commensurate with the value that solar provides to the electricity system. This latter alternative is known as the VOS tariff.

The VOS tariff is one of the most commonly discussed alternatives to NEM. Unlike NEM, the VOS tariff dissociates the customer payments for electricity consumed from the compensation they receive for solar electricity generated. Under a VOS tariff, the utility purchases some (i.e., the net excess) or all of the generation from a solar installation at a rate that is independent of retail electricity rates.[5, 6]

1.1 Calculating the Value of Solar

Calculating the VOS rate (the amount paid by the utility for distributed solar generation) involves identifying the tangible benefits and real costs that solar provides to the electric system. The value of each is calculated and those values are summed to form a bundled purchasing rate for solar generation. The electric system benefits (e.g. cost savings) attributable to solar can include energy, capacity, transmission and distribution (T&D) system deferral, and line loss reductions, as well as environmental and other benefits as assessed in each jurisdiction. The VOS rate can also be used as a means through which the utility receives compensation for the costs of integrating the solar generation into the electricity system or for providing transmission and distribution services in connection with the solar system. As a general principle, the categories

[5] This purchase can be compensated as a financial bill credit (at the purchasing rate) rather than a kWh credit under NEM to avoid causing a tax liability from income.
[6] There are hybrid transaction possibilities where kWh credits offset the customer's consumption and the solar purchase rate is given for the excess kWhs beyond the consumption.

and calculations are real-dollar costs and savings to the electric system that will be monetized in all ratepayers' rates over time.

In principal, the VOS tariff does not represent an incentive or subsidy, but rather compensation for real value provided by the solar installations to the electric system.[7] Some categories of value (such as energy and line losses) are not controversial, and there is general agreement among a variety of stakeholders on their inclusion in the VOS rate. Other categories, such as generation value, are location-specific. Other categories, such as environmental benefits, are not as simple, eliciting much debate among stakeholders. Although the VOS can also be used as a means to compensate utilities for the services provided to the solar customer (e.g., integration and T&D), few calculation methodologies to date have included the costs of solar to the electricity system.[8] There is an emerging body of research, both completed and in-process, addressing the VOS categories and their calculations (See Appendix A for high level summaries of a few analyses).[9]

This report specifically avoids analyzing whether it is appropriate to transition away from NEM, which payment mechanism is preferable (VOS is one of many), and, if the VOS mechanism is chosen, how the VOS rate could be calculated. These questions are specific to each state's and utility's jurisdictions. This analysis assumes the decisions have been made to support distributed solar deployment using a VOS program and that the VOS calculation methodology has been agreed upon or even completed. The questions that this analysis addresses are: What happens next? How do utilities, in conjunction with local stakeholders, build a VOS program that supports distributed solar markets over time, that is efficiently administered, and that maximizes the long-term goals and benefits to all stakeholders that were intended in deploying solar resources? This analysis presents the main design options of setting up a VOS program--beyond calculating a VOS rate number--and will help readers consider some of the key major decisions necessary to create an effective VOS program.

The report is structured in five main sections:

- Section 2: provides a historical perspective on distributed solar markets and how the rationale for the VOS mechanism, the research to date, and the program design elements fit within the ongoing market evolution;
- Section 3: covers lessons learned from two case studies and from early VOS programs, and creating a program for successful market transition
- Section 4: develops three conceptual market frameworks through an analysis of VOS rates relative to the current costs of solar
- Section 5: covers VOS program design elements
- Section 6: synthesizes the main points of the report.

[7] An additional incentive may be provided on top of a VOS rate as part of a program design decision.
[8] The costs of solar to the system were not included in the creation of the example VOS rates for the analysis presented in this report.
[9] In this paper, references to 'electric system cost reduction' or 'utility cost savings' and similar language refers to the diversity of possible categories of value (benefits and costs), their inclusion or exclusion, and their calculation.

1.2 Program Design

VOS program design includes the structure and rules for participation. It can include the basic parameters around eligible customer classes, technologies, and project size applicability, as well as payment frequency, rate recalculation frequency, stakeholder communication methods, contracting periods, aggregate participation limits, additional incentive support, and the program transition process away from NEM. Basically, program design includes the nuts and bolts of how a solar customer applies for and receives the VOS rate.

VOS program design is equally as important as the calculation of the VOS rate. In fact, how a VOS program is designed could impact whether specific policy objectives are reached, to a greater extent than the VOS rate. The design attributes of a VOS program with a low tariff rate could elicit greater participation over the long term than another program offering a higher rate. Solar incentive programs over the last two decades bear the lessons of such unintended consequences. Excessively favorable incentives have been known to create 'market exuberance' that can attract more system installers to the market, some with more experience and qualifications than others. Incentives designed flexibly can respond when solar market prices or conditions change rapidly. Incentive programs with performance requirements may help prevent underperforming systems. Examples from Spain, New Jersey, and Nevada, among others, demonstrate some of these lessons with long incentive program waitlists, rising installed prices, and poor installation practices (Voosen 2009). Programs with too many design or paperwork requirements add disproportionately to installation costs. Time and experience has already smoothed out many of these issues for existing, successful programs. VOS programs will have uniquely different issues than incentive programs because of their inextricable link to value calculations, but the general principle of increased success through thoughtful program design applies.

1.3 Analysis

This report creates a VOS program design framework for utilities (independently operated utilities, municipal utilities, and rural cooperatives),[10] regulators, and stakeholders to consider when implementing VOS programs. The report presents a "range of options" for jurisdictions to consider as they contemplate their VOS program goals and design options best suited to meet its policy goals and priorities. It does not suggest which solar value components could be included as part of the VOS rate, how the components are calculated, or a specific VOS rate for a particular utility or location (though hypothetical examples are included for instructive purposes). Appropriate options will vary across solar markets; what works in Hawaii will not necessarily work in Kansas. Accordingly, this report differentiates how program design varies across three solar market types.

The three market types are characterized by whether the levelized cost of deploying solar PV technology (LCOE), expressed on a kWh basis, is greater than, approximately equal to, or less than the VOS rate. Using the LCOE is, arguably, an imperfect measure of the price-competitiveness of solar. While the LCOE calculation attempts to account for the total costs of solar deployment, it is realistically unable to capture these costs perfectly. There may be

[10] This analysis focuses on the perspective of the traditional utility. Other perspectives, including that of the DG solar customer-owner or of the independent third-party owner, are also important. The authors decided to limit the scope of this analysis to the impact of a VOS program on a traditional utility.

interconnection or O&M costs that are unaccounted for, actual generation output of the system may vary, and financing terms may deviate from those assumed. Nevertheless, LCOE still provides a generally acceptable method to approximate system costs.

As such, the three solar market types discussed in this report are:

- **Price-support Market (LCOE-PV > VOS Tariff)**
    - VOS rate is not sufficient to economically recover the cost of DGPV installation
    - Additional incentives are likely needed to fill the difference between the VOS payments and the levelized cost of PV, in order to sustain the solar market
- **Transitional Market (LCOE-PV ≈ VOS Tariff)**
    - VOS rate is nearly equal to the levelized cost of PV installation
    - Few incentives are needed to sustain the solar market
    - VOS program design needs to reflect the shift toward equalization
- **Price-competitive Market (LCOE-PV ≤ VOS Tariff)**
    - VOS rate is higher than the cost of PV installation
    - The market is self-sustaining
    - VOS program focus turns away from providing economic support to other key factors (e.g., annual program installation caps).

Importantly, as market conditions change over time, an existing market could transition from one type to another type of market. This could result from an addition or reduction of state or federal incentives, shifts in fossil fuel prices, or a disruption in the market. The market is not expected to be static, and it will be important to be alert to changes over time and consider these in future policy structures. After a few years, pioneering VOS programs are likely to help inform policy changes, program design, and updates needed to address those transitions more effectively and completely.

2 Historical Distributed Solar Markets: VOS in Context

This section reviews analysis and experience to date that can inform future VOS program design and puts the scope and breadth of value-based electricity purchases in context. It provides an historical perspective on support structures for distributed solar installations over the past two or three decades, and contrasts the functionality of the VOS rate structure with NEM and other mechanisms.

2.1 VOS Functionality in the Context of Existing Policies

Utilities and policy makers might decide to support DGPV for a number of reasons. These could include meeting growing customer demand for solar and meeting broader environmental goals. But why pursue a VOS program specifically? Distributed solar generators have used a number of standard transaction mechanisms over the last 25-30 years. These standard transaction options differ from competitive solicitations (e.g. requests for proposals [RFPs]), in that they are open to any generator at any time (unless an overall program budget, capacity cap, or other programmatic limit was met). Table 1 provides a summary of the various mechanisms. Note that two are applied on the customer-side of the meter reducing on-site load (parallel generation and NEM), and three are applied on the utility-side of the meter as wholesale purchases.

One attraction of VOS programs is that utilities could count all of the purchased distributed solar generation produced in their territory toward meeting renewable mandates (e.g., renewable portfolio standards, or RPS). Nineteen states, plus the District of Columbia (DSIRE 2013), have solar or distributed generation set-asides in their policies. Utility purchases under a VOS program could count towards RPS compliance (if RECs are bundled) in these states.

NEM is one of the most commonly used policies in the United States today. It is defined by SEPA as

> "a billing mechanism for electric utility customers with grid-connected distributed generation (DG). NEM facilitates use of the electric utility system, allowing customers to virtually manage generation not used immediately, in exchange for kWh and/or financial credits. Those customers subsequently may draw on their credits at other times to offset consumption and/or charges when the DG system is not meeting their full energy needs, up to the total amount they have banked within the applicable period (often 12 months)" (Cliburn et al. 2013).

Although not part of a formal rate proceeding, NEM conceptually values solar generation at the retail price of electricity (though NEM credits provided to customers can be below retail rates in many cases). By reducing the kWh billed at the retail rate, some NEM programs set the value of the customer's on-site generation as equal to the retail rate.

Under the Public Utilities Regulatory Policies Act (PURPA), utilities are obligated to purchase independent power producers' electricity at the utilities' avoided energy cost. The avoided cost is usually determined in a contested proceeding before the utility's regulatory body, and the methodology is not consistent across states. Sometimes it is based on the wholesale electricity rate for a full generating portfolio, sometimes the power plant on the margin, sometimes in other ways. Avoided costs to the utility usually include energy generation but can also include avoided emissions, line losses, generator capacity value, T&D capacity, and ancillary services (values which may be part of VOS programs, among others).

Table 1. Distributed Solar Transaction Mechanisms

Transaction Type	Enabling Mechanism	Benefit	Timing	Commentary
Qualifying facility (QF)	PURPA	Avoided energy costs	1980s-present	Rates based on avoided energy costs, with methodologies that vary across states and utilities (e.g., avoided portfolio energy, marginal energy, new resource energy, renewable energy, etc.). Not particularly economic for distributed solar; low historical participation rates (though has emerged in niche locations like North Carolina and Idaho as solar prices have declined and unique state circumstances allow).
Parallel generation	Utility policy	Retail rates + avoided energy costs	1980s-present	Offset consumption as solar generation occurs, but excess is purchased at avoided costs; suitable for large loads that will absorb all generation at all times. Not widely utilized since PV systems are sized much smaller than load to maximize benefits.
NEM	PURPA with state or utility policy details	Retail rates	1990s-present	Offset retail rates directly; manage excess generation as kWh credit for future consumption. Strong policy expansion over last two decades; core enabler of most state DGPV activity (along with federal, state, and utility incentives).
Feed-in tariff (FIT)	State or utility policy	Tariff based on profitable cost of solar	2000s-present	Design calculations ensure a defined rate of return for solar projects and most often ignore utility rates (i.e., they are based on the cost of solar to produce power profitably). Limited examples in U.S., though extensively used in Europe.
VOS	State or utility policy	Tariff based on the VOS to utility	2011-present	Design calculations based on the value of the solar electricity to the utility and/or their system (not the cost of solar). Limited active or proposed programs, though significant general interest.

A feed-in-tariff (FIT) is "an energy supply policy focused on supporting the development of new renewable energy projects by offering long-term purchase agreements for the sale of [renewable] electricity" (Couture et al. 2010, p.6). The calculation methodology of a FIT differs compared to the VOS policy. While the VOS policy is focused on estimating the value of the solar generation to the utility and/or their system, most FIT policies are focused on estimating the cost of solar to the project owner while also providing the generator compensation for the costs plus a "reasonable" return (Couture et al. 2010; Couture 2014). Therefore, a FIT policy aims to pay the developer/owner for the actual cost of the project (including a profit) whereas the VOS policy aims to pay the estimated value the project provides to the utility system.

VOS is one of the transaction mechanisms used to compensate customers for the power their solar systems generate. State incentives are often used in addition to these transaction mechanisms to fill a remaining economic gap. The incentives are reviewed and periodically adjusted since the solar market, equipment costs, and soft costs change over time. More detail on VOS program design is included in later sections.

2.2 PV Penetration Market Stages

NEM has driven significant market activity over the last five years, in combination with incentives, solar technology cost reductions, and third-party contracting. The other three mechanisms covered in Table 1 (QFs, parallel generation, and FITs) have not gained widespread traction in the United States, especially for distributed solar. NEM-based solar policies and markets vary significantly across the United States, reflecting varying economic conditions across states and utilities, including different solar resources, installed costs, solar industry business models, policies, and incentives. These different solar markets can be characterized as non-economic, pre-economic, and grid-competitive (referring to the comparison of the cost of PV to the retail price of electricity).

A non-economic market exists when the LCOE-PV is significantly higher than the price of grid power. The payback period for a DGPV system is long and only early adopters may be willing to make the investment. A market has transitioned to pre-economic when the LCOE-PV is nearing the price of grid power. The payback period is shortened and more individuals are willing to make the investment in PV. Third-party leases may facilitate development and state or utility incentives may serve to fill the remaining gap between the cost of solar and the cost of utility-provided power. When the solar market has reached grid competitiveness, state and utility incentives may no longer be needed (although market conditions can change). A variety of financing options are likely to be available, and the payback periods for solar development are acceptable to investors.

The goal of characterizing general PV market stages is to lay a framework for identifying whether a separate incentive (in addition to the VOS tariff) could help DGPV projects to be a more economic option (or close enough to economic) after the transition to a VOS tariff. If a solar market remains pre-economic after the implementation of a VOS tariff, little distributed solar development can be expected.

It is only within the last two years that solar in portions of certain states (e.g., Hawaii, California, and Arizona) has moved from pre-economic to grid-competitive, allowing for the reduction or elimination of state and utility incentives while still maintaining high solar growth rates. Utilities in those three states account for 65% of the national distributed solar market capacity in MW (Makhyoun et al. 2014). The federal investment tax credit[11] (ITC), for which solar PV is eligible, remains in the calculation and is expected to remain a key driver until it changes in 2017.[12]

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[11] Specifically known as the business energy investment tax credit and the residential renewable energy tax credit for the respective taxpayers.

[12] Beginning on January 1, 2017, the ITC changes from 30% to 10% of installed costs for business taxpayers and is eliminated for residential individual taxpayers (DSIRE 2014a). If DGPV is grid-competitive, residential customers may still choose to install systems, even with the lower ITC. If economics are still pre-economic, residential customers may choose third-party companies to install systems on residential homes (in states where they are

Again, this report takes no position on the public policy of comparing solar costs to current utility rates and state and federal incentives.

While the VOS concept is the latest distributed solar transaction mechanism to emerge, there is currently more discussion than there are tangible program examples. Only one active utility program exists (Austin Energy n.d.). Other activity includes the withdrawal of a proposal by CPS Energy in San Antonio, Texas (Hamilton 2013), and significant state policy and stakeholder action to set up program rules in Minnesota (Minnesota Dept. of Commerce 2014) as well as at the Tennessee Valley Authority (TVA) (TVA 2014). All other momentum around the VOS mechanism involves research and theoretical development by industry, utilities, and consultants. It remains to be seen how much traction VOS policy will ultimately gain, but the conceptual interest is strong.

allowed). As business taxpayers, they retain ownership of the solar system, secure the benefits of the tax credits, and sign a lease or performance contract with their customers (to whom they could pass some/all of the benefit.

3 VOS in Context

It is important to set the VOS policy in context before proceeding to discuss program design analysis. The focus of this report is on the way that a VOS program is designed, or the VOS policy framework, from the perspective of the traditional, conventional utility. While calculating the VOS rate value is a critical discussion, equally important is how the VOS policy is structured and implemented through the key program design elements. This section describes the VOS mechanism, considers some important features, and examines the functionality of the VOS mechanism in the context of existing policies. Importantly, there are two analyses that are not addressed in this report: 1) the efficacy and process of VOS rate calculation methodology (Appendix A summarizes existing literature) and 2) the comparison and contrast of the relative merits and challenges of the VOS mechanism to other policies.

3.1 VOS Definition and Features

As described earlier, a VOS program establishes a transaction between the utility and the self-generating customer. The VOS rate is determined by: 1) identifying the categories in which solar provides both benefit and cost to the utility and society, 2) calculating values of each of these categories (assigning positive and negative as appropriate), and 3) combining these components into a single rate. The VOS rate represents the real value of distributed solar to the utility, considering both costs and cost savings, which will be monetized in all ratepayers' electric bills over time.

There are several ways to design the transaction. Under the design used by Austin Energy, typically called a buy-all, sell-all transaction, self-generating customers buy all of the electricity they use at the applicable retail tariff and sell all of their PV generation to the utility at the VOS rate. The purchase of electricity for use on-site is completely decoupled from the sale of the solar generation to the utility. And as long as the costs to the utility of integrating the PV system and providing T&D services are included in the VOS rate,[13] this structure can keep the utility "whole" and significantly reduce or eliminate cross-subsidization. The utility receives payment for all of the services that solar customers use through the retail rate, just the same as it does with non-solar customers. In addition, if utilities purchase the solar generation bundle with the associated renewable energy credits (RECs), they can apply those credits toward DG or PV set-asides associated with RPS policy mandates.

An alternative VOS program design is the net excess transaction, where the customers offset their own electricity demand with self-generated solar power before selling excess generation to the utility at the VOS rate (Keyes and Rábago 2013; Starrs 2014). The self-generators may claim the environmental attributes of the power they use on-site or sell the rights in the form of unbundled RECs to the utility.

One disadvantage of the net excess method is that, since it does not decouple the solar customer's purchase of electricity from the sale of their solar generation, it does not address the cross-subsidy and cost-recovery issue that is presented by net metering. This point is notable

[13] The example VOS rates that were created for the analysis in this report do not include the estimated costs of solar PV to the electricity system. While including the costs, in addition to the benefits, of solar to the electricity system is in line with the general philosophy of a VOS calculation methodology, only the components that have been most commonly included in existing calculations were used for this analysis.

since, to some extent, the transition from net metering to an alternative mechanism, such as VOS, has been spurred by concerns about the potential for cross-subsidization within the residential sector and utilities' varying ability to recover fixed costs (Kind 2013).

In addition, the total incremental incentive (on top of the VOS rate) per system may be estimated as larger, depending on how the retail rate compares to the cost of PV in a particular market. This is because the incremental incentive would be applied to a smaller portion of the generation from each system (the net excess portion). As a result, program costs could be higher until solar price-competitiveness is achieved, particularly if a large number of systems are needed in order to comply with an RPS policy. It should be noted that the net excess transaction approach to VOS program design has not yet been applied or studied in the context of any particular market (see Section 5.4 below for more information).

3.2 Overview of VOS Calculation Methodology

Generally, the first step in calculating a VOS rate is for the utility, regulators, legislators, or other stakeholders to propose which value and cost components could be used to build the VOS rate. Once the components that will be included have been determined, a calculation methodology will be established for each component. The benefits are represented by a positive number, while any costs are represented as a negative number. Summing these components to get the net of all benefits and costs yields the VOS rate, which represents the value that solar provides to the electricity system.

The goal of this report is not to estimate the VOS rate number for any value or cost component in any particular location; this is necessarily specific to each utility, and for vertically integrated utilities, is determined through contested ratemaking proceedings. Other research by NREL, Rocky Mountain Institute (RMI), and Interstate Renewable Energy Council (IREC) lays the foundation for performing VOS rate calculations (Denholm et al. 2014; Hansen, Lacy, and Glick 2013; and Keyes and Rábago 2013). Summaries of some of this existing VOS rate calculation research are presented in Appendix A. NREL's 2014 report (Denholm et al 2014) examined these various solar valuation methodologies, concluding that the seven main components being used, include:

- Energy
- Emissions
- T&D loss savings
- Generator capacity
- T&D capacity
- Ancillary services
- Other costs and benefits, such as other environmental impacts, fuel price hedging, diversity, market price suppression, O&M costs, integration costs, grid support services, and resiliency.

Note that a VOS rate calculation for a particular location may consider the specific physical characteristics, market conditions, and policies that are applicable. If a utility has a large service territory, variations of VOS rates or program designs within that territory could be considered.

3.3 VOS Policy Principles

Before creating any new distributed solar policy, it is important for policy makers and regulators to articulate the main principles or objectives that the policy is expected to attain. In order to establish VOS program principles, it is important to understand the different stakeholder perspectives about the benefits and challenges of a VOS program. This section provides an overview of some of the main VOS policy goals and challenges that could be considered in the establishment of a VOS policy.

Table 2 shows, for the major stakeholders, a sampling of VOS policy objectives and concerns specific to VOS programs. While not comprehensive, the table shows that there are several themes common across all stakeholders. By identifying these themes, it may be possible to establish them as VOS policy design principles that can help set the stage for policy success through meeting the needs of key stakeholders.

Key themes that could be used as VOS policy design principles include:

1. Sufficient utility revenues for grid services provided to support solar growth
2. Recognize the VOS benefits and costs–not only to the utility system, but to society as well (to the extent the benefits are codified in utility financial structures)–and pay the project owner appropriately
3. Limit cost to customers, both those with solar and those without
4. Create a transparent VOS rate calculation methodology, including input assumptions and updates.

Specific stakeholders in any particular location will have their own motivations and concerns. A successful program will be informed by discussions with key stakeholders about their policy objectives and concerns. The common themes in the discussions should then be prioritized by the stakeholders and used to establish policy design principles. This achieves two main objectives: 1) the VOS policy design will be structured to consider key elements that are most important to most, if not all, stakeholders, and 2) the VOS program design has a better chance for success.

Table 2. Stakeholder Perspectives on VOS Program Design

Stakeholder	VOS Policy Objective	VOS Policy Concerns
Utility	-Maintain reliability of the entire system -Meet growing customer demand for DGPV -Be "made whole," or paid for all electric grid services used by decoupling DGPV payments from retail rates -Reduce/eliminate cross-subsidization, where non-solar customers pay to support services exclusively used by DGPV -Create transparent payment -Design an efficient, straightforward way to manage program -Track actual customer load, not just net load -Meet other environmental goals/mandates	-Realize cost savings of societal benefits/externalities -Ratepayer VOS program transparency -Which terms could be included as part of VOS rate calculation? -What calculation method will be used for each term? -What input assumptions will be used for all calculations? -Limit cost to customers -How can a program be structured to keep the utility whole? -Who owns the renewable energy certificates (RECs)?
PV Generating Customer	-Support on-site generation (customer, utility, or third-party owned) -Benefit from all kWh generated with a rate that will cover costs -Be paid a rate over a long period of time to recover lifetime costs -Meet individual/societal environmental goals	-Be properly compensated for all solar generation (which VOS terms, calculation method, input assumptions) -Avoid overpaying for utility services -What input assumptions will be used for all calculations?
Non-solar customer	-Benefit from low cost electricity -Benefit from reliable electricity supply -Support public renewables goals	-Non-solar customers paying for services that support solar systems -Ratepayer VOS program transparency
Policymaker	-Support customer desire for DGPV -Create transparent VOS tariff -Fairly compensate utilities for their services to support DG on their systems -Reduce/eliminate cross-subsidization -Meet environmental goals for society -Provide mechanism to meet renewable energy mandates	-Limit cost to customers -Structure a program that keeps the utility whole while also limiting incremental costs to the utility (i.e., avoid straining existing infrastructure) -Ratepayer VOS program transparency
Solar Industry	-Help all customers explore solar options with clear process for program changes -Be paid for all kWh generated over a reasonable and predetermined time period, with a rate that will facilitate market transactions and cover costs -Benefit from and pay for utility services -Provide long-term investment certainty for investors	-Be properly compensated for all solar generation, including environmental goals -Provide a smooth transition from current solar transaction method -Minimize negative disruptions to customer prospects, hiring, cash flow, and other business issues -Ratepayer VOS program transparency – which terms will be included? What calculation method will be used for each term? Input assumptions?
Society	-Improved economy -Better air/water quality	-Limit cost to society

Sources: Kind (2013); Keyes and Rábago (2013); Hansen, Lacy, and Glick (2013)

3.4 VOS Case Studies

This section illuminates lessons learned about the VOS mechanism to date through detailed case studies of the Austin Energy VOS program and the Minnesota statewide voluntary VOS program.

Austin Energy: Municipal Utility Case Study

In 2012, Austin Energy (Austin, Texas) was the first U.S. utility to enact a VOS mechanism (CPR 2013). As of that year, it was the nation's eighth-largest publicly-owned electric utility, serving over one million residential customers, with nearly 13 billion kWh. The Austin Energy service territory is 437 square miles, half of which is outside of the city limits (CPR 2013).

Austin Energy has shown a strong commitment to clean energy, working toward city council-mandated solar and renewable energy goals and offering several renewable energy programs including residential solar rebates, a performance-based incentive for commercial solar, and the GreenChoice green power purchasing program. The utility has over 850 MW of wind power and 30 MW of utility scale solar, and obtains 20.7% of its total generation mix from renewables (CPR 2013).[14] Over 3,250 customer-sited PV systems are signed up for the utility's VOS rate (CPR 2013).

One of the goals of establishing a VOS tariff was to create a program that does not provide different benefits to customers based on their consumption. Under net metering, customers that used more energy received more benefit from installing solar since they were able to offset a greater amount of grid-supplied electricity. In designing the VOS program, the utility aimed to provide fair compensation for the solar generation, avoid impacts of solar programs on non-solar customers, and enable the utility to recover costs (Harvey 2014). In line with these goals, a buy-all sell-all program design was chosen such that payments for solar generation are decoupled from billing for customer electricity usage. Customers pay the retail rate for all electricity they consume, and are compensated for the full amount of generation from their on-site solar systems through electric bill credits at the VOS rate (CPR 2013).

Austin Energy and Clean Power Research performed the VOS rate calculation, which included the components of energy savings, generation, capacity value, T&D deferral, loss savings, and an environmental value (Rábago et al. 2012). The initial VOS rate was set at $0.128/kWh (levelized value), with all solar generation valued equally. Under the program rules, the VOS rate can be reassessed and adjusted annually, with adjusted rates applied to new solar customers (CPR 2013; Harvey 2014). Adjustments to the calculation were made in both 2011 and 2014, resulting in VOS rates of $0.128/kWh and $0.107/kWh, respectively.[15] These declines reflect lower natural gas price projections (as based on the futures market), an adjustment of the assumed project life from 30 years to 25 years, less assumed savings due to avoided losses, and a change in the calculation methodology to account for the market changes within the Electric Reliability Council of Texas (ERCOT) (Harvey 2014).[16]

[14] Austin Energy also has a number of sustainability programs including a green building rating program, a 35% renewable energy supply goal by 2020, an active energy efficiency program (that avoided construction of a 700-MW power plant), auto-cycling thermostats, internet-enabled thermostats, and 185 public electric vehicle charging stations (CPR 2013).

[15] The decline in the calculated VOS rate caused concern for some stakeholders, who had anticipated that increasing natural gas prices would result in a higher VOS since the energy value component of the VOS calculation is a main driver of the final VOS rate. However, while current prices were volatile, the futures market did not predict rapid natural gas price increases.

[16] The VOS rate was originally calculated assuming it would be implemented in a vertically integrated market environment. After Texas implemented a nodal electricity market, Clean Power Research recalculated the rate using nodal market data from one year. When additional data were available, CPR re-ran the analysis using two years of

Thus, in the current market, the combination of the VOS tariff and the federal tax credit does not cover the cost of distributed solar installations in the Austin Energy territory. Accordingly, the utility provides a solar rebate on top of the VOS rate. This creates an acceptable return on investment and drives distributed solar adoption. Like the VOS rate, the solar rebate has also declined in several stages over time, going from \$2/W to a current \$1.10/W (Harvey 2014). Installed solar costs, however, have not declined to the same extent, going from an average of \$3.50/W down to \$3.25/W. Even given these economics, customer uptake of solar has been steady, as shown in Figure 1. Continued investment may be encouraged by the maturation of the solar industry, increased public acceptance, and positive utility support for solar.

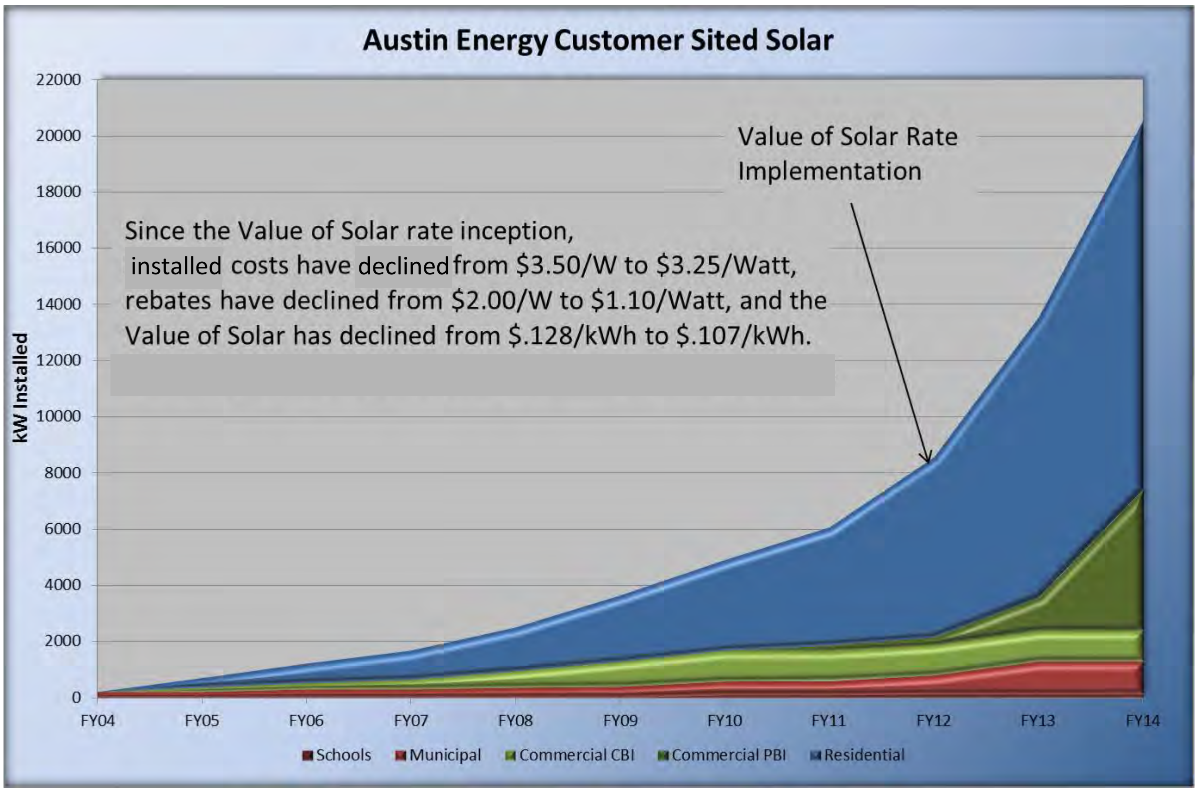

Figure 1. Austin Energy customer-sited solar

Re-printed with permission from Tim Harvey's Utility Solar Conference presentation
Source: Harvey (2014)

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nodal data with the intent of extrapolating future nodal pricing. It was found that market prices had lowered from \$0.073/kWh to \$0.038/kWh, which would have resulted in a drop in the VOS rate. In addition, it was decided that adjusting the VOS rate in line with historical nodal prices was not in alignment with the agreed-upon use of long-term avoided costs, so the VOS calculation method was refined. The implied heat rate (mmBtu/MWh) of the market was adjusted to recognize the on-peak production of solar, and was validated through modeling and comparisons with known outputs for base-load plants. This was multiplied by forecasted natural gas prices and the result multiplied by modeled PV fleet production, using relevant discount factors. The sum of the results were converted into an energy value expressed in \$/kWh (Harvey 2014).

In a 2014 presentation at the SEPA Utility Solar Conference, Austin Energy's senior program specialist, Tim Harvey, provided some observations and recommended improvements to the Austin Energy VOS program (Harvey 2014):

1. **Rollover credits.** As the program was originally designed, any unused VOS bill credit was zeroed out at the end of the year (CPR 2013). This was done to avoid any negative tax implications that could complicate the program. Customers, however, were displeased with losing "their solar energy." After further consideration, it was determined that the compensation for the solar generation is not considered income since the credit is nonrefundable and nontransferable. This relieved any potential tax implications to the carry over of credits. As such, Austin Energy is proposing to the city council that the solar credits roll over indefinitely, as long as they are applied toward the electricity bill and remain nonrefundable and nontransferable.
2. **Updated, transparent calculation methodology.** As originally designed, Austin Energy could update the VOS calculation on an annual basis to reflect changing market circumstances (CPR 2013). However, customers were upset to learn that they were not included in the methodology development process. Wanting to be responsive to these concerns, Austin Energy is proposing (and intends) to have the VOS calculation methodology reviewed as part of the annual budget planning process, which includes commission and city council approval.
3. **Variability of the rate.** Because the rate can vary from year to year, both the utility and its customers are concerned about the possibility that the VOS tariff could fluctuate significantly. Austin Energy is proposing that the current year's VOS rate be averaged with previous years' rates to create a rolling average VOS rate factor, thus decreasing volatility from year to year.
4. **Third-party solar leases.** The current VOS program only allows for participation of customers who own their solar systems. The utility is considering allowing the participation of customers who lease their systems through third-party providers.

Overall, Austin Energy posits that it is successfully supporting customer-sited solar while ensuring utility revenue recovery and the avoidance of rate impacts on non-solar customers.

Minnesota VOS Policy – State Case Study

The State of Minnesota passed legislation in 2013 that required the Minnesota Department of Commerce (MN DOC) to establish a calculation methodology to quantify the value of DGPV. The legislation required specific components to be included: energy and its delivery, avoided capacity, transmission capacity, T&D line losses, and environmental value. The methodology was then to be passed to the Minnesota Public Utilities Commission (PUC) for approval. Investor-owned utilities could voluntarily choose to file a VOS rate as a replacement to NEM. To date, no Minnesota utilities have established or offered a VOS rate to replace NEM.[17]

The objectives in establishing the Minnesota VOS program, with respect to the methodology, were to (Grant 2014):

[17] Xcel did file a VOS rate on May 1, 2014 (Revised June 19), but it has not been adopted into a program.

- **Accurately account for all relevant value streams** (benefits net of costs) from a societal perspective
- **Simplify** the methodology and input data sets (where possible and warranted)
- **Provide transparency**
- **Facilitate modification**, if necessary, in future years.

In order to operationalize the Minnesota VOS legislation, the Minnesota DOC conducted an extensive stakeholder process in the fall of 2013 (MN DOC n.d.). They engaged Clean Power Research to conduct the technical and analytical support. RMI and Karl Rábago of Rábago Energy (who led the Austin Energy program design while working at that utility) provided context and background. Four workshops were held to provide background to engaged stakeholders on key issues, and more than 50 sets of comments were received, which helped shape subsequent workshops and inform the final draft VOS methodology. According to Bill Grant, the Deputy Commissioner at the Minnesota DOC, Division of Energy Resources (Grant 2014), Minnesota utilities were concerned that the valuation was not based on least-cost or avoided cost, while environmental groups were concerned that VOS tariff payment level would not be high enough to support solar development without the use of additional incentives.

The Minnesota DOC submitted the draft methodology to the Minnesota PUC in January 2014. The Minnesota PUC approved the method in March and issued an approval order on April 1, 2014 (MN DOC n.d.). At the 2014 SEPA Utility Solar Conference, Deputy Commissioner Grant explained some key characteristics included in the Minnesota VOS policy:

- **Voluntary -** Investor-owned utilities may voluntarily apply to the Minnesota PUC to enact a program in lieu of net energy metering
- **Project size limitations -** PV systems must be under 1 MW in size
- **Decouple use and generation -** Customer electricity usage is separated from production
    - Customers are billed for their total electricity consumption at the retail rate
    - Compensation for the solar system is through a bill credit at the VOS tariff
- **Value**
    - **Production-based -** VOS rate is expressed in ¢/kWh, levelized over 25 years, and adjusted for inflation on an annual basis
    - **Includes key elements** – VOS rate represents the value of distributed solar to the combination of the utility, its customers, and society
    - **Rigorous, transparent calculation**
        - Once the VOS rate is established in any one year, that rate schedule is applicable over the full contract period to all customers who enter during that year
        - The valuation will be updated annually for new annual VOS program participants to incorporate utility inputs for the value of PV in the year of installation

- A VOS utility-specific input assumption table is part of the utility's application and will be made publicly available
- A VOS utility-specific calculation table will break out the value of individual components and the computation of total levelized value, and it will be made public

- **A tariff is not an incentive -** A VOS tariff is not intended as an incentive for DGPV, and it is not intended to replace existing incentives or prevent future incentives.

The Minnesota DOC calculated sample results for the Minnesota VOS rate shown in Figure 2. As shown, the biggest drivers of the rate are avoided fuel cost, avoided environmental cost, and avoided capacity cost. The calculation used the federal government's avoided cost of carbon.

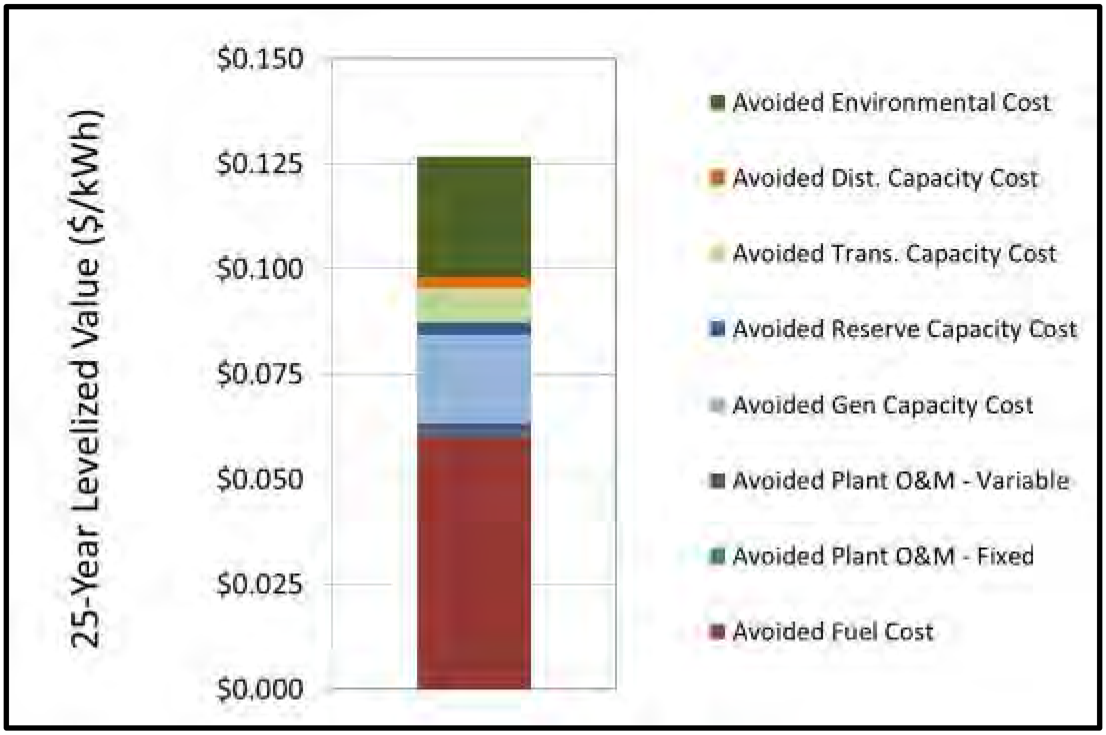


Figure 2. Minnesota VOS – sample calculations

Source: MN DOC (2014)

At the SEPA Utility Solar Conference, Bill Grant provided some reflections from the Minnesota process (Grant 2014):

1. **NEM alternative.** Input from some stakeholders during the public process appears to indicate that the VOS tariff mechanism may be a good alternative to NEM. The program sets a new solar standard that appears to meet many of the objectives set out at the beginning. Even so, the MN DOC raised the NEM cap so that DGPV could still go forward if voluntary adoption of the VOS program is slow by utilities.

2. **Cross-subsidies addressed.** Customers pay for their entire electric energy usage at the standard rate; this is one way of addressing cross-subsidy concerns.
3. **Stakeholder involvement critical.** The state government DOC was generally satisfied with the public stakeholder process and felt it was a good choice to involve all stakeholders in the methodology development of the resulting tariff.
4. **Third-party business models.** It is unclear if VOS programs are compatible with third-party business models where solar companies own the equipment on a utility customer's site; the consumer then signs a lease or performance sales contract with the equipment owner. This was not examined closely in Minnesota because these business models are not currently available to customers and cannot be tested in the state. View Section 5.2 on program eligibility.

4 Solar Market Characterization: Comparing the VOS to the Cost of Solar

This section presents the methodology by which three market frameworks were developed to characterize the solar market under various VOS tariffs, resource qualities, and incentive levels. As mentioned previously, the three market types that can occur under a VOS tariff are a price-support market, a transitional market, and a price-competitive market. This characterization is accomplished by comparing the levelized cost of solar (LCOE-PV) and the VOS tariffs in order to determine the difference. Similarly, these frameworks can be used to characterize markets under any of the transaction types used to support DGPV deployment.

The goal of this effort is *not* to conduct a state-by-state analysis of solar market under a VOS for specific locations, but rather to characterize the market for a variety of representative situations. Understanding the range of possibilities, and how the variables interact to influence the market, provides a foundation from which to discuss VOS program design elements. Additionally, NEM was not included in this analysis as the VOS was considered as a replacement for NEM programs.

4.1 VOS Case Profiles

The goal of defining VOS case profiles is to recreate, using publicly available data, a range of outcomes that could span various geographic, policy, and market scenarios. It is not meant to show any bounding limits of the VOS, but only a reasonable potential range of low, medium, and high values that could represent a variety of state or utility characteristics. The components included in this VOS study are easily estimated using published information and includes energy, avoided capacity, T&D capacity, line losses, and environmental costs. It does not include items such as O&M, fuel hedging, integration costs, and non-traditional items such as grid support services, resiliency, etc. as these are not currently easily calculated using publicly available data at a nationwide level (presumably they could be easier at a particular location). Each jurisdiction will have differing conditions, and will need to explore which value categories the relevant stakeholders want to include and how those values can be formulated into a VOS rate that best represents the conditions in their specific location. Methodology and assumptions used for generating the generic VOS rates used in this analysis are discussed below.

Modeling Assumptions

The modeling assumptions and sources of cost information that were used in the development of the three VOS profiles are described below (more details are described in Appendix B). The differences between the three VOS case profiles are detailed in Table 3. The U.S. Energy Information Administration (EIA) 2013 Annual Energy Outlook is the source for avoided capacity and avoided fuel calculations, as well as the T&D deferral calculation and escalation rate.[18] Other basic, generic input assumptions that were needed to complete the cost calculations (e.g., discount rates, tax rates, solar system life, reserve margin, etc.) were set at mid-range values. Using published data for generation construction costs—in this study a combustion turbine[19]—and average T&D expenses, and then varying the resource timing need or avoided

[18] This analysis was performed before EIA released the Annual Energy Outlook for 2014, in May 2014.
[19] A combined cycle turbine was used because it is typically the next resource to be added to the generation fleet in a utility integrated resource plan.

investment, allows for a range of outcomes while bypassing any jurisdictional intricacies such as forecast T&D costs and the marginal generation unit type. Readers interested in understanding the range of data and modeling options for conducting VOS rate calculations are invited to consult an NREL report that details a range of simplified and more complex methodologies for calculating a VOS rate (Denholm et al. 2014). The assumptions included herein, by term, are:

> **Avoided capacity**. The EIA overnight build cost (EIA 2013a) for a new, combined-cycle natural gas combustion turbine (shown in Appendix B of this report) is used as the basis for avoided capacity. It is assumed the plant is constructed over a two-year period. An economic carrying charge was applied to annualize the investment in the generation facility. Depending on the VOS case profile considered, the avoided capacity investment was either deferred for 5 or 10 years, assuming no immediate capacity need in the middle or low VOS cases, or there was an assumed immediate capacity need in the high VOS case. Limiting the marginal unit to a combined-cycle natural gas turbine with variable fuel prices simplifies the calculations.
>
> **Avoided fuel**. Three natural gas forecasts from the EIA 2013 Annual Energy Outlook were used to generate avoided fuel mixes for the three profiles. These were converted to costs using the displaced natural gas heat rate for a combined-cycle natural gas plant and the solar output (accounting for degradation).
>
> **T&D deferral.** Average national T&D costs from the American Society of Civil Engineers from 2001-2010 are used for T&D deferral costs. These are divided by the average national retail sales from EIA for the same period (EIA 2013a).
>
> **Environmental.** Environmental values for the three profiles are sourced from the National Academies of Science for natural gas-fired generation (National Research Council [NRC] 2010). This provides a breakout of values for non-greenhouse emissions, which includes sulfur dioxide (SO_2), nitrous oxide (NO_X), and particulate matter. Greenhouse gases are listed separately, which allowed for their inclusion in only the high VOS case profile.
>
> **Losses.** An average loss of 7% is applied to the sum of the avoided capacity, avoided fuel, T&D deferral, and environmental for each of the three cases (EIA 2013).

Using the sources of cost information above, low, medium, and high VOS case profiles were created. The three cases attempt to capture a realistic range of VOS rate outcomes that might occur—again, only based on publicly available data. Individual utilities or jurisdictions can include additional terms if they have access to additional data. The low VOS case assumes no immediate capacity needs, and that T&D deferral and environmental benefits are not included in the VOS calculation. The medium VOS case assumes slightly different inputs, including T&D deferral after 5 years and environmental benefits not related to greenhouse gas emissions. The high VOS case assumes immediate capacity needs, T&D deferral, and all environmental benefits. The details of these inputs into the VOS case profiles are given in Table 3.

Table 3. VOS Category Assumptions

Category	Low	Middle	High
Avoided fuel[20]	Natural gas prices from EIA Annual Energy Outlook 2013 "High Oil and Gas Resource" case	Natural gas prices from EIA Annual Energy Outlook 2013 "Reference" case	Natural gas prices from EIA Annual Energy Outlook 2013 "Low Oil and Gas Resource" case
Avoided capacity	No generation needed for 10 years	No generation needed for 5 years	Immediate capacity need
T&D Deferral	No T&D benefit is assumed	5 year T&D deferral based on ASCE average T&D expenditures from 2001-2010 and the retail sales from the same period (EIA 2013a)	Immediate T&D avoided investment based of ASCE average T&D spend from 2001-2010 and the retail sales from the same period (EIA 2013a)
Environmental	No environmental benefit is assumed	Non-greenhouse benefit of natural gas electric generation (NRC 2010)	Non-greenhouse and greenhouse (CO2) benefit of natural gas electric generation (NRC 2010)

Note: several candidate VOS terms were not included in this national-level analysis because publicly available sources of data are not readily available. These include T&D loss savings, O&M, ancillary services, fuel hedging value, diversity, integration costs, grid support services, resiliency, and market price suppression.

Sources: EIA (2013a); NRC (2010)

VOS Modeling Results

The VOS component calculation results are outlined in Table 5. The largest VOS component is the avoided fuel cost. It ranged from about 3.5 ¢/kWh to a little over 6 ¢/kWh, with changing natural gas prices driving the difference. Avoided capacity is the second-largest component, ranging from a little over 1 ¢/kWh to a little over 2 ¢/kWh. The high VOS case incorporates the assumption that there is an immediate need for generation capacity. Avoided environmental cost adds up to nearly 2 ¢/kWh, which is almost as much as the generating capacity component for the high VOS case. This is because of the societal impact of carbon included in the high VOS case. Avoided costs associated with T&D deferral are relatively small, with the highest case having a value of just under 0.2 ¢/kWh. Losses are a function of the sum of all the other components. Adding the value components together gave a range of nearly 5 ¢/kWh to 11 ¢/kWh, with the medium case at 7.5 ¢/kWh.

[20] The "High Oil and Gas Resource" case indicates that substantial supplies are available in the future, which has a dampening effect on pricing.

Table 4. VOS Hypothetical Ranges (¢/kWh)

Category	Low	Middle	High
Avoided fuel	3.6	5.2	6.1
Avoided capacity	1.0	1.5	2.1
T&D deferral	0	0.14	0.19
Environmental	0	0.18	1.9
Losses	0.3	0.49	0.72
Total	**4.9**	**7.5**	**11.0**

4.2 Calculating the Levelized Cost of PV

The next step in the characterization of the possible markets under a VOS tariff is to calculate the LCOE-PV for a variety of representative locations. This was done using the System Advisor Model (SAM)[21], a solar cost model developed by NREL (NREL 2014a). In order to capture the costs of solar development across the entire United States, the LCOE-PV was calculated for the most populous city of each state. This method was chosen over using the cities with the best resources, since doing so could bias the output toward a lower LCOE-PV. Since the VOS mechanism is widely discussed as a tariff to compensate customer generators in the residential sector, calculations were based on a residential-sized PV system of 4 kW_{DC}. These and other input assumptions are summarized in Table 5, below.

Table 5. Input Assumptions for LCOE Calculations in the System Advisor Model

Variable	Value
PV array	4 kW_{DC}; 7 modules per string, 2 strings in parallel 30 degree fixed-tilt; south facing, 77% derate factor
Panels	Produced an output of 284.7 W_{DC} each
Inverter	Rating: 3,800 W, 240V
Degradation	0.5% per year decline (default)
System cost	\$3.77/W_{DC} (default)
Financing	20 years
System life	25 years
Real discount rate	7.5%
State Income Tax	Weighted population rate
State Sales Tax	Median of highest and lowest
Inflation rate	1.8%
Weather Data	TM3 for most populous city in each state (Class 1 preferred)

[21] Version 2014.1.14 of the System Advisor Model was used for this analysis. Since this analysis was completed a new version of SAM has been released, which includes updated LCOE data.

A separate set of LCOE-PV calculations were made for five different levels of incentives, holding all else constant:

1. No federal or state incentives
2. A 30% federal investment tax credit (ITC) only
3. The federal ITC, plus existing state incentives (as of Jan 2014)
4. The federal ITC, plus a hypothetical state investment tax credit of 30% applied to all states
5. The federal ITC, plus a hypothetical state upfront cash incentive of $0.80/W applied to all states.

The last two calculations, which assume a hypothetical level state incentive in each location, were intended to investigate the result of implementing either an ITC or a cash incentive in each state, regardless of whether one is currently offered. Currently, eleven states offer investment tax credits, the value of which fall in the range of 10% - 50%. A hypothetical investment tax credit of 30% represents the median of these actual tax credits. The hypothetical cash incentive was set at $0.80/W because this is the median of the currently offered incentives.

LCOE-PV results

SAM outputs provided the LCOE-PV for the largest city in 49 states and the District of Columbia assuming different levels of incentives. The range of LCOE-PV values at each incentive level are given in Table 6. The range excludes the values for the state of Alaska. Due to the low solar resource quality, Alaska has the highest LCOE-PV of all locations studied for every scenario. In addition, several of the scenarios for Alaska yield the same LCOE-PV result because no state incentives are offered. Thus, a summary of the LCOE ranges is more informative without this outlier. Complete data for all 50 states are available in the Appendix C.

Table 6. Range of Life-cycle Cost of PV for Different Incentive Levels (Excluding Alaska)

Incentive Level	Low End of LCOE-PV (¢/kWh)	High End of LCOE-PV (¢/kWh)
No incentives	14.5	22.8
30% federal ITC only	9.3	14.6
30% federal ITC + existing state incentives	4.0	13.1
30% federal ITC + 30% state ITC	5.6	8.6
30% federal ITC + $0.80 state capacity-based incentive (e.g., grant, rebate)	7.6	11.8

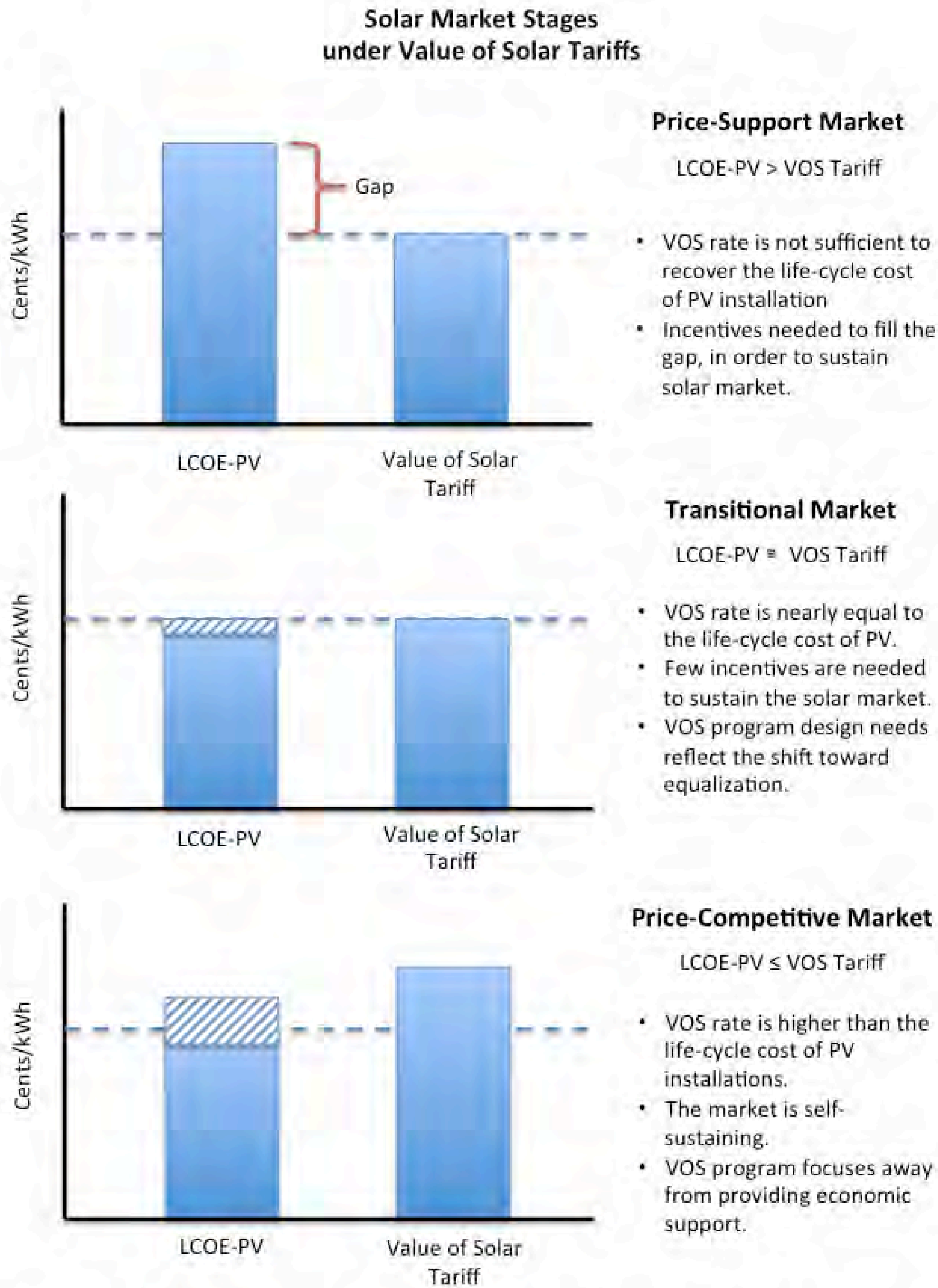
4.3 Comparing the VOS profiles with the LCOE-PV

Next, the difference between the VOS profiles and the LCOE-PV was determined by subtracting the LCOE-PV from the VOS level for each permutation. It is important to note that this methodology of calculating the difference assumes that the payment structure being employed in the VOS program is ‘buy-all/sell-all.’ In other words, all of the solar generation produced by the system is purchased by the utility for the VOS rate. An alternative program payment structure is one where the utility only pays the solar system owner the VOS rate for the excess generation that is fed onto the grid (i.e., the generation that is not immediately consumed on-site is not purchased by the utility). These different payment structures have vastly different effects on the economics of solar.

Understanding that this analysis is assuming a 'buy-all/sell-all' payment structure, the difference between the VOS profiles and the LCOE-PV indicates the degree to which the VOS payment would cover the cost of a solar development. For each location and each scenario, the cost of solar is greater than, near to, or less than the VOS level. The factors that impact this result include the amount of solar resource available at the most populous location within each state, the sales and income tax rates of the state, the federal and state incentives assumed to be in place, and the VOS payment level.

Figure 3 illustrates various market types that are a possible result from the calculation (LCOE-PV minus the VOS rate). The two bars in each chart show the cost of solar and the level of the VOS tariff in three market types.[22] The shaded areas indicate the range in which the LCOE-PV may fall for the particular market type. A price-support market occurs when the LCOE-PV is significantly greater than the VOS tariff. In this case, additional incentives are needed to fill the gap in order to sustain the solar market. A transitional market occurs where the VOS tariff level is approaching the LCOE-PV and limited incentives may be needed. And in a price-competitive market, the VOS rate is higher than the LCOE-PV. As we will see in following sections, VOS program design needs will differ for each of these market types.

[22] Figure 3 is for illustrative purposes of market types and is not based on analysis.



Notes: This figure illustrates solar market types that may occur under a VOS tariff. It does not present analysis results. The shaded areas indicate the range in which the cost of solar may fall under that market type.

Figure 3. Solar market stages under VOS tariff

Results of Comparing the VOS level with the Cost of Solar

When the difference between the VOS rate and the LCOE-PV is calculated for all locations and all scenarios considered in this study, all three market stages are represented. The range of results of these calculations is shown in Figure 4. The figure shows that when no incentives are accounted for (the scenario depicted by the red bar), the difference between the VOS and LCOE-PV is below zero for all of the locations and levels of VOS. In other words, the assumed VOS tariff does not cover the LCOE-PV, creating a price-support market. As the difference between the VOS and LCOE-PV approaches zero, the market can be said to be transitioning from price-support to a transitional market. Scenarios that fall above the x-axis are in the price-competitive stage. For example, a price-competitive market occurs for all locations in the scenario where there is a high VOS, a 30% federal ITC, and a hypothetical 30% state ITC (represented by the green bar on the right-hand side of the figure).

Some locations and scenarios that were modeled for this study fall within the price-competitive market stage. These are indicated by the ranges where the bar rises above the zero line. When all existing incentives are considered (the orange bar), there are at least some price-competitive markets for each level of national, generic VOS tariff considered here. Note again that this analysis did not include net metering, as the VOS was considered a replacement for NEM. When a high VOS level was assumed, the largest number of price-competitive markets occurs. There are a few locations for which the solar market is shown to be price-competitive under a high VOS rate, with only the 30% federal ITC in place. Notably, under a high VOS rate and a 30% federal and 30% state ITC, every location was found to have a price-competitive solar market.

Figures 5 and 6 show the results in a different form. The points on these graphics show the result of each cost comparison for all locations and all scenarios. Figure 5 shows the results for the scenario without incentives and those with existing incentives. Figure 6 shows the results for the scenarios that include hypothetical state incentives. Similar to Figure 4, the data points that are above the x-axis indicate locations where price-competitive markets exist for the given scenario.

The location names are intentionally left out of the result displays because the purpose of this analysis is not to focus on specific locations, but to generally characterize the markets that might be expected to occur under various levels of VOS tariffs and various levels of incentives. These data are only general representations; they are not intended to be used to make conclusions regarding the potential economic viability of distributed solar in a particular location.

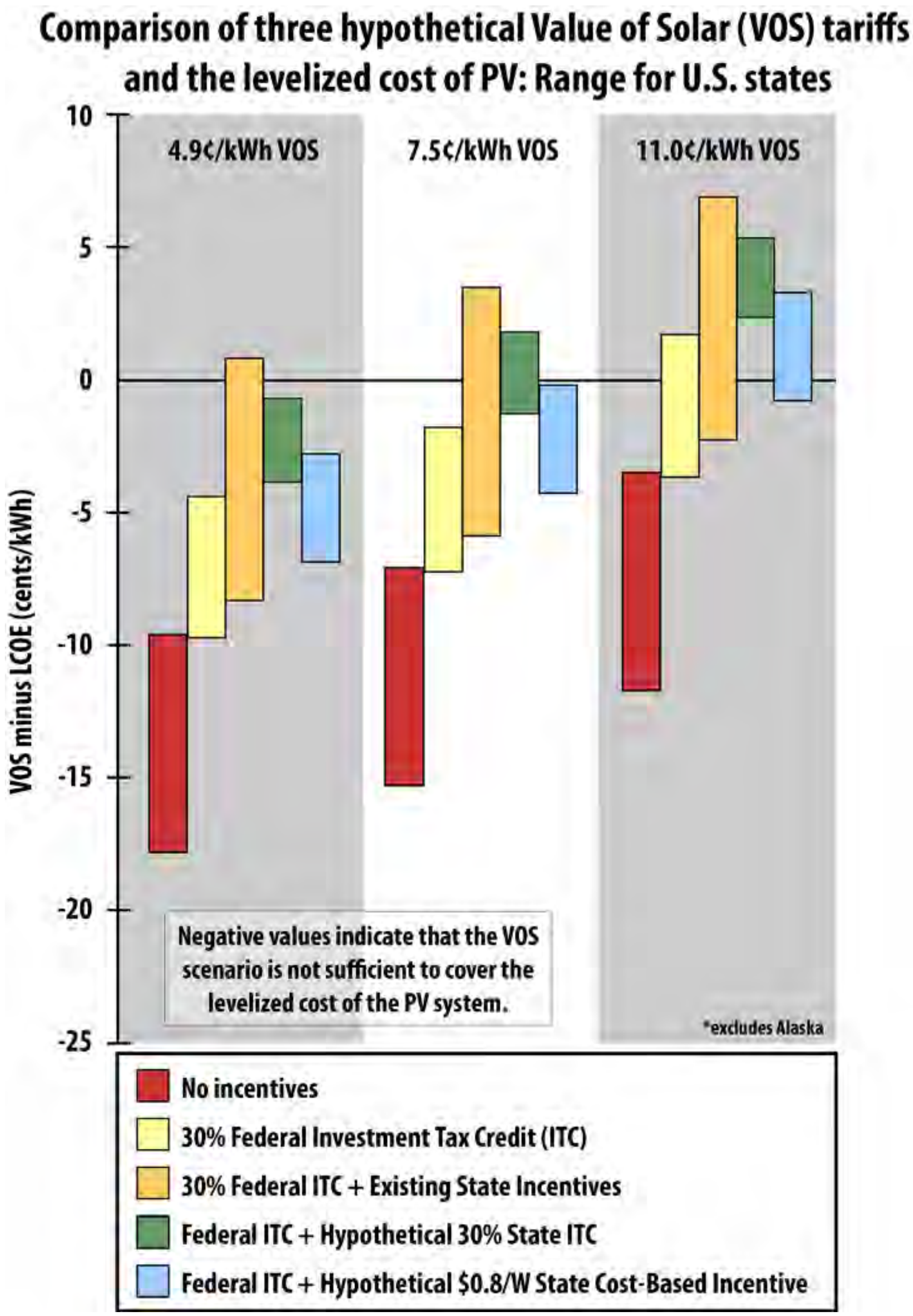


Figure 4. Comparison of VOS and LCOE-PV

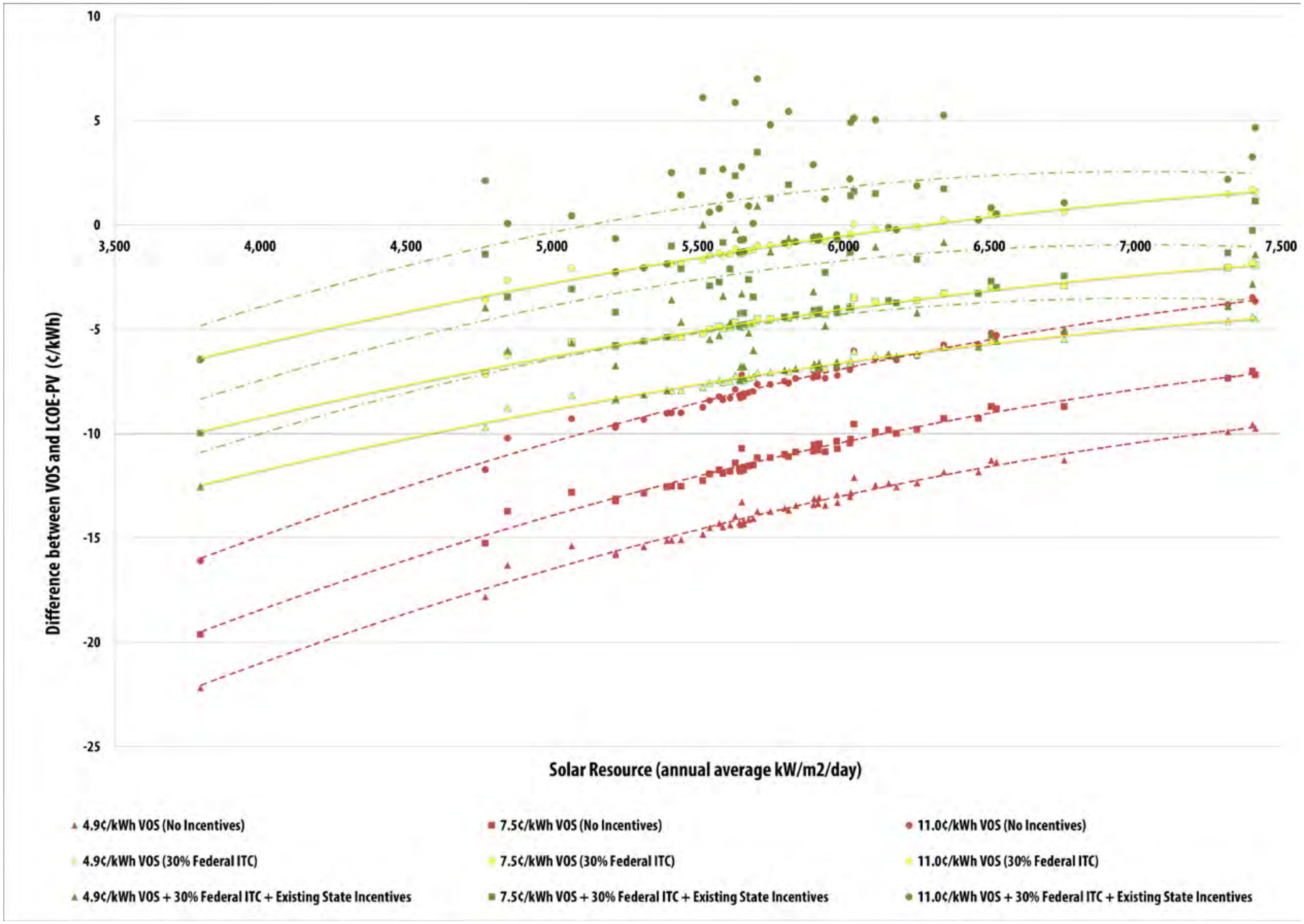


Figure 5. Difference between three levels of VOS tariffs and the LCOE-PV in 50 U.S. locations: scenarios with no incentives and existing incentives

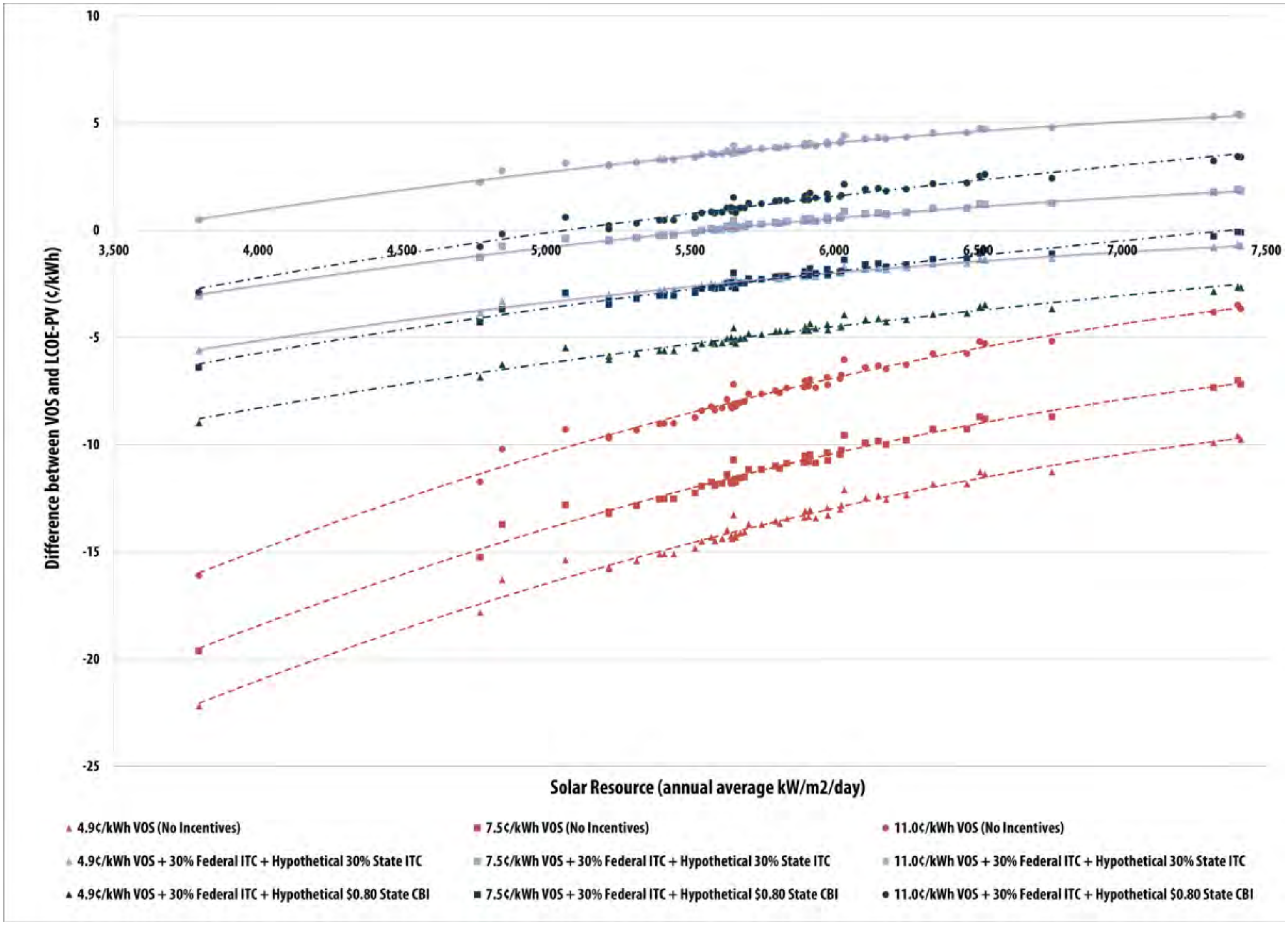


Figure 6. Difference between three levels of VOS tariff and the LCOE-PV in 50 U.S. locations: scenarios with hypothetical state incentives

Key Takeaways

Some key takeaways from the modeling effort are summarized below. The points are categorized by the assumptions regarding the available incentives, as well as the assumption regarding the level of VOS tariff available. See the Appendices for more details on the results of the modeling.

No Incentives

- If no federal and state incentives are taken into account, the three hypothetical VOS tariff levels selected for this study are substantially lower than the LCOE-PV derived from the modeling assumptions, indicating price-support markets in all locations.

Federal ITC only

- When only the 30% federal ITC is taken into account (no state incentives), the economics of the modeled PV systems improves for the high VOS tariff case. Results indicate a transitional market in most locations and a price-competitive market in nine locations.
- Low and medium VOS tariff levels result largely in price-support markets.

Federal ITC + Existing State Incentives

- A high VOS tariff along with existing state incentives yields a competitive market in the majority of locations (32 out of 50). Only one location is pre-economic under this scenario.
- The medium VOS tariff results in 10 price-competitive markets and 17 transitional markets; the rest are pre-economic.
- Most locations studies under the low VOS tariff are pre-economic, although there are a handful of transitional (9 markets) and 2 price-competitive.

Federal ITC + Hypothetical 30% State Tax Credit

- Under a high VOS rate plus a 30% federal ITC and a 30% state investment tax credit, solar is price-competitive in all locations.
- With a medium VOS rate, more than half of the locations are price-competitive and only one location is price-support.
- The majority of locations are transitional with a low VOS tariff.

Federal ITC + Hypothetical $0.80/W State Capacity Based Incentive (CBI)

- A high VOS tariff along with a federal ITC and a $0.80/W state CBI yields a competitive solar market in nearly every location (47 out of 50). The other three locations have transitional markets.
- The medium VOS tariff results in mostly transitional markets; only 9 are pre-economic.
- Only 3 markets are transitional with a low VOS tariff; the rest are all pre-economic.

Low VOS Level

- Very few instances of price-competitive markets occurred under the low VOS tariff level modeled for this study.

- When the federal ITC + a hypothetical 30% state ITC is considered, 45 locations show transitional markets. The remaining five locations have price-support markets.
- For the federal ITC + existing state incentives, the low VOS tariff results in 2 price-competitive markets and 9 transitional, with the rest being pre-economic.
- All or most (at least 47/50) locations have price-support markets for 3 of the incentive scenarios modeled (no incentives; federal ITC only; federal ITC + hypothetical $0.80/W CBI).

Medium VOS Level

- A medium level VOS tariff yields mixed results for the various scenarios modeled. Economic markets are present in only two scenarios: federal ITC + existing state incentives (10 states) and the federal ITC + a hypothetical 30% state ITC (the majority of states).

High VOS Level

- Under the high VOS scenario, all but three locations have price-competitive markets under the hypothetical incentive scenarios (federal ITC + 30% state tax credit (all markets) or a $0.80/W CBI).
- More than half of the locations (32 of 50) have price-competitive markets when the federal ITC+ existing state incentives are included in the modeling. In this scenario, only one location results in a price-support market.
- The federal ITC only high VOS tariff resulted in 9 price-competitive markets, 2 pre-economic, and the majority transitional. Without the federal ITC, no markets were even transitional; they all were pre-economic.

One general takeaway is that, under the assumptions of this analysis, the presence of federal and state incentives has a greater impact on the solar market stage than the VOS level (see Figure 4 and Appendix C). When the level of VOS is held constant, the shift of the LCOE-PV is a direct result of the incentives being included. For example, note the difference between the LCOE-PV results for the "no incentive" case and the "30% Federal ITC + existing incentives" case. Not surprisingly, the LCOE-PV range bar shifts upwards (toward a more competitive market) with the addition of incentives. Now compare the LCOE-PV ranges when the VOS level is increased, while the level of incentives is held constant. In all cases, increasing the level of VOS also shifts the LCOE range upwards, but the shift is smaller than that induced by the addition of incentives. This indicates that incentives have a greater impact on market competitiveness than the level of VOS, under the analysis assumptions.

The other key takeaway is that a VOS program will most likely be dynamic. As market conditions change, the relative values and costs of the solar system, the market in which it is participating, and other key factors will change. Therefore, it may make sense to reevaluate the tariff structure and design as conditions change over time. The challenge is how to do that in such a way that keeps investors neutral to the changes; in other words, any adjustments cannot undermine the overall project economics that lead to investment, or investors may not be interested in supporting DGPV in those locations.

This section presented an analysis comparing the current LCOE-PV in 50 U.S. cities with 15 different scenarios for compensating and incentivizing customers for distributed solar generation. The difference between the cost of installing a solar system and the payments received by the owners is presented as an indication of the status of the market in each location. The results provide decision makers with a framework for considering the potential market impact of implementing a VOS rate and the importance of state-level incentives in supporting the transition from a pre-economic market to a competitive market over time.

5 VOS Program Design Framework

This section examines a VOS program design framework, outlining the principles that can be used in developing the administrative rules and functional decisions of a VOS program.

A VOS program is somewhat similar to other utility-managed customer solar programs, such as NEM, as well as incentive programs, both of which have a well-established history of design improvements and best practices in the United States. However, a VOS tariff is not an incentive–it is a utility rate program. Moreover, VOS programs often represent a market shift away from net metering, and as such, have potentially higher stakes among customers and the solar industry. No single program design may satisfy all interests perfectly, but a thorough approach to the design and implementation process can improve the end results. For example, a goal of a VOS program might be to support the solar industry and enable a successful transition from NEM. One method of doing so could be to layer a multi-year, declining incentive program on top of the VOS rate, gradually transitioning to an incentive-free market as solar costs decline. While this design construct could result in a higher VOS program cost in the early years, it would avoid a significant market disruption during the transition period, essentially narrowing the near-term difference between the chosen VOS tariff level and the current cost of solar.

Note that this report is not a complete VOS program design guide–the nascent and emerging nature of the VOS concept does not lend itself to a known checklist or best practices. In fact, the VOS design concepts introduced here are likely to raise more questions than answers, and further research will be required to design VOS programs to suit the regional context of any particular utility. At this point, investigating the lessons learned and design options of other policies can provide insights for developing new policies (for more information on policy design options and lessons learned, see Couture et al. 2010; Bird et al. 2012; Lantz and Doris 2009; and Cory and Swezey 2007). Proactively identifying and addressing potential issues during the design phase may be easier than retroactively addressing a forgotten issue. Similarly, this framework does not favor or promote one program design decision over another. The approach lays out the range of options with directional indicators of their net effects.

The LCOE-VOS comparative analysis in the previous section indicated that the "price-support market," where the VOS rate is less than the LCOE-PV, is likely to be the most common solar market condition currently across the United States (individual situations may vary and likely will be calculated for each jurisdiction). While it may not be the case in every circumstance, it is a good starting point to assume that a VOS alone may not be enough to cover the LCOE-PV of development given today's solar costs. Going forward, other market types and design needs will emerge over time, as VOS rates are adjusted and the LCOE-PV declines. Given this assumption, the design discussions below use the price-support market as the default market framework, noting adaptations for the "Transitional" (VOS = LCOE-PV) and "Price-competitive" (VOS > LCOE-PV) markets, where applicable. And while some programs may be designed as a buy-net sell-net (or net excess) transaction, we only investigated the buy-all sell-all transaction used in Austin and considered in Minnesota.

This analysis generally defaults to the most common scenario driving VOS program adoption to date–a roof-mounted, PV system on a residential customer using a single, bundled VOS rate. Variations of this scenario are discussed, but unless noted, this is the default arrangement.

The design categories by section include:

- 5.1 *Balancing Design Decisions*: Setting objectives, understanding the necessary design and stakeholder interest tradeoffs, and placing the program needs in the context of what can be rapidly changing market and business conditions
- 5.2 *Installation Details*: Covering the installation rules for participants
- 5.3 *Rate and Contract Treatment*: Establishing how the VOS rate is implemented within a long-term program
- 5.4 *Price Supports*: Considering an additional incentive on top of the VOS rate
- 5.5 *Administrative Issues*: Thinking through the internal utility program operations and accounting.

Text Box 1. Design Application: Hypothetical Utilities

Each section below discusses the range of program design options from which decision makers can choose in shaping and defining an overall program, akin to a program design menu. Category by category, the range of options is intended to be inclusive of a variety of options and to provide the context for specific decisions to make the report more tangible. Two hypothetical utilities were created with different characteristics to create example programs, and contrast the differences between different program designs. The text boxes within this chapter explore how the utilities might approach VOS program design.

Utility A is located in a cost-support market and is seeking to:

- Transition from NEM to VOS tariff for residential customers only
- Utilize solar installations to assist with future generation capacity needs
- Keep billing simple and utilize its existing billing system
- Plan for future VOS rate values that could be realized in the future.

Utility B is located in a price-competitive market and is seeking to:

- Transition from NEM to VOS tariff for all customers
- Leverage new technologies, creating a diverse fleet of distributed resources
- Seek out a utility return on investment where possible in the price-competitive market
- Develop a sophisticated customer information and billing system.

These two utility examples will follow each section below in similar textboxes, weaving the sometimes broad list of options into a specific program decisions and their related thought processes based on these goals.

5.1 Balancing Design Considerations

One theme throughout this section is how to balance competing design philosophies to create a useful program, as shown in Figure 7. The accuracy of a program's design needs to be balanced against the costs to attain that accuracy and the impacts on program participation. In other words, what level of complexity is a VOS program equipped to manage, and will added complexity actually lead to more satisfactory results or equivalent benefits?

For example, location-specific VOS rates could be designed to represent a greater or lesser VOS across an individual utility's service territory, which would manifest in utility cost savings at the distribution or transmission level. While it is more accurate to reflect each individual solar system's value to the utility system, the question remains whether this level of accuracy yields sufficient benefit or practicality. When put into practice, the VOS rate could vary across hundreds of individual distribution circuits or in several larger geographic areas. But this accuracy needs to be balanced against the simplicity of a single VOS rate across an entire utility's territory. Limiting the number of different VOS rates[23] will likely facilitate calculations, rate updates, customer marketing and communications with customers, the industry and other stakeholders. Just as utilities set electricity rates based on an average customer consumption profile per customer class, a single VOS rate, representing the average value that solar provides across the system may be easier to set and implement than multiple rates.

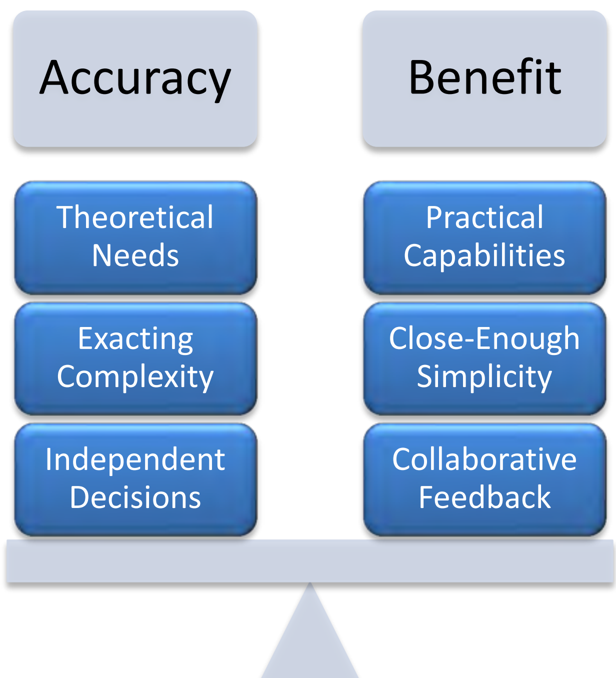


Figure 7.VOS program design balance considerations

[23] Different types of VOS rates could include those for residential customers versus non-residential customers (or those with and without demand charges), and distinct rates or adders for customers installing distributed solar in preferred locations on the electricity system.

These types of decisions include technical accuracy, but also program design rules. For example, historical rebate programs were very prescriptive about installation details to promote long-term performance given upfront ratepayer or taxpayer investments. Under a VOS tariff, a utility only pays for actual electricity produced at a rate that represents its calculated value. Thus, will the VOS program design rules try to maximize system performance, or are the administrative and transaction costs of setting up and managing VOS program applications enough to warrant greater involvement in ensuring system performance? Throughout the program design phase, these types of needs and interests of stakeholders (e.g., utilities, the solar industry and electricity customers) will be balanced against one another. The degree of independent decisions by the utility versus collaborative feedback from solar stakeholders and decision makers will vary significantly according to the type of program implemented and the program's goals.

5.2 Installation Details

A VOS program will typically include administrative rules on a range of design issues, such as participant eligibility and project or program size limits. However, although the VOS concept is often regarded as a distinct *alternative* to NEM, the design of and lessons learned from NEM and other existing policies provide useful information to guide the development of a VOS program. For example, one comprehensive list of renewable energy policy design options is found in a report on Feed-in-Tariff (FIT) designs, called *A Policymaker's Guide to Feed-in-Tariff Policy Design* (Couture et al. 2010).[24] Even though it is focused on FIT policies, the design and implementation options are widely applicable to other policies, whether they are rates or incentives. Another example is provided in *Distributed Solar Incentive Programs: Recent Experience and Best Practices for Design and Implementation* (Bird, Reger, and Heeter 2012). In fact, details from both of these documents were used as a foundation to consider VOS program design options in the subsections below.

Eligible Participants

Options for VOS participant eligibility include:

1. **Residential and small business customers** (i.e., energy-only rate customers): The driving interest behind VOS programs as an alternative to NEM (from some stakeholder perspectives) is separating consumption from generation and remedying concerns of fixed cost recovery. Typically, residential customers (and often small businesses) pay virtually all of the system's fixed costs through the volumetric energy rates (i.e., on a kWh basis). As such, residential customers are the main target participants for a VOS program.
2. **Non-residential customers** (i.e., any that have demand charge rate structures): Customers with a demand charge generally pay for a higher proportion (though not all) of the system fixed costs than customers on all-energy rates. A VOS program may still be of interest to ensure appropriate compensation for DGPV generation contributed to the system, and to make sure that all utility costs are paid to the utility. A different VOS rate may need to be set for customers that are subject to demand charges.
3. **Third-party-owned solar installed on electricity customer property**: The third-party ownership (TPO) model, in which customers sign leases or energy contracts with solar

[24] See Table ES-1 on p. xi of the Executive Summary of the report.

companies rather than purchasing or financing the solar installation outright, is popular in U.S. states where it is allowed. VOS program designers may need to specify whether TPO systems will be eligible for a VOS rate, and might look for precedents set by existing state or utility policies. If the TPO model is already active in an area and these systems are eligible for existing policies (e.g. net metering), backing out of this precedent could be disruptive to the market and raise stakeholder concerns. If the TPO model is not active in an area, either by explicit utility or regulatory decision or local market conditions, the VOS program design may represent a point of (re)consideration. Some utilities have expressed concern around TPO activity because as regulated monopolies, they have exclusive rights to sell electricity to customers in their service territories, something which is clouded when TPOs sell solar electricity to the same customers. Under the VOS mechanism, electricity consumption and solar generation are separated, which may reduce regulatory concerns.

4. **Third-party company on non-load locations**: Independent solar projects on greenfield or brownfield sites could also be considered. These are akin to a community solar or distributed solar merchant plants, which are common in feed-in tariff markets. In theory, the value that a solar installation provides to the system is independent of any tie to a particular customer. This development option could potentially expand the solar market significantly, especially in suburban and rural areas where suitable land can be found. One potential concern with this option, however, is the possibility that a limited number of customers could rapidly fully subscribe to the program, or that a few customers could reach distribution circuit penetration limits, essentially crowding out other eligible customers. One can envision a project developer that finds the VOS rate economic and installs dozens of projects in one territory, blocking others from participating in the program. Another consideration is that this option may not be feasible until the transition from net metering (which is clearly tied to a specific customer load) to a VOS tariff (which is not necessarily tied to a specific load) is complete. If this project type is excluded altogether, VOS policy designers would need to pay attention to the definition of the customer type or define the on-site load (e.g., is one streetlight sufficient?) in tandem with individual project size limits.

Individual Project Size

Project size limits have historical origins in net metering, which are often based on the size of the solar system relative to the customer's usage. VOS rates are dissociated from customer use and projects would be limited more by interconnection penetration limits on distribution feeders.[25] However, limits might also be considered as part of an overall goal to provide the opportunity for broader customer participation by prohibiting one or two large projects from fully subscribing to the program (if capacity or budget limits exist) or distribution circuit level penetration limits (to spread out and diversify geographic participation).

Any individual project could be limited in capacity based on the participant or customer type or expected generation relative to historical customer use or load. From a program operation perspective, simple size limits by customer type would be most easily administered (e.g., residential 10 kW; small business 50 kW; or 100% or 120% of total on-site annual load).

[25] Austin Energy's VOS rate is compensated through bill credit, which effectively correlates project size to the annual bill, depending on bill credit rollover rules.

Aggregate Program Size

The concept of creating an aggregate VOS program size limit could be related historically to either utility or state incentive program limits, based on defined annual program budgets, or to state or utility net metering program caps. However, a VOS program could be theoretically self-limiting and may not need an aggregate limit. A VOS rate is based on the anticipated monetary value to the utility system, so in theory, there are no customer cross-subsidization or lost revenue issues. In other words, a perfectly designed VOS tariff is equivalent to a point of indifference for the electric system and ratepayers, where they will take as much distributed solar energy as the market can provide at that price point, or that makes sense on any particular feeder or substation. Greater solar supply or a change in natural gas prices would increase or decrease some of the VOS rate components accordingly. For example, as solar penetration goes up, the solar capacity value goes down under most capacity value calculation methods (Hoff et al. 2008). However, in reality, this is only true if the VOS rate is adjusted in short time intervals (even real-time) rather than in more practical intervals, such as annually (see also 'Contract and Rate Treatment' section below). In most cases there will be a lag between the solar energy installed, the VOS rate adjustment, and the future solar market response to the rate change. This could be handled with shorter rate interval adjustments, but these could be disruptive to the solar market as solar developers and consumers are planning projects or securing financing. Another option is to forecast future VOS rates so that the market can internalize upcoming changes, but this can create a market rush if there is a significant drop anticipated.

Even still, there will be a lag between the payment for the solar electricity and the value it provides--and when that value to the utility system and society is monetized by the utility. This will vary by VOS category, with energy value savings occurring more or less in real-time, with costs for deferred capacity, grid infrastructure deferrals, or environmental costs occurring on longer time cycles.

In a more practical sense, interconnection penetration rules and limits (outside the scope of the VOS rate) may themselves limit DG on individual distribution feeders and, by association, the overall VOS program activity.

If the VOS program sponsor decided to limit program size, a variety of options are possible, including solar capacity targets, annual budgetary expenditure limits, calibrating to utility demand or demand growth, or similar metrics.

Generation Technologies

VOS programs by definition include solar PV technologies and are dominantly applied to flat panel, fixed PV systems. However, concentrating PV could also be considered while non-PV generation technologies like micro-CSP, wind, or fuel cells may be technologies to consider in the future since they may offer different utility value profiles than the VOS tariff (and thus would require their own unique VOS tariff calculation and VOS program design).

Supporting Technologies or Installation Configurations

A variety of supporting technologies and installation configurations could be considered for compatibility with a VOS program and could be encouraged under a VOS tariff. Single- or dual-axis PV tracking will increase solar capacity and extend the shoulders of the solar generation curve into the evening hours. Allowing tracking to be included in a VOS program does not represent a significant philosophical or administrative hurdle, but the appropriate compensation may need to be considered since the initial capital cost increases as a result. Tracking will increase annual performance and the system will receive additional revenue at the VOS rate. Tracking can also enhance the solar capacity value. A variable VOS rate based on time-of-use or critical-peak pricing is also possible, but creates additional administrative, metering, and billing complexity. Program designers will have to determine whether to offer enhanced value for tracking or other supporting technologies.

Smart inverters hold the promise of increased visibility and control at the edge of the grid. Advanced inverter functions allow for more elaborate monitoring and communication of the grid status, the ability to receive operation instructions from a centralized location, and the capability to make autonomous decisions to improve grid stability, support power quality, and provide ancillary services (NREL 2014b). To the extent that the utility is able to dispatch smart inverters to provide voltage-amp-reactive (VAR) power support rather than kilowatt-hours, for example, a differentiated value proposition could be created for that class of customer. These value streams would need to be calculated and applied in the VOS rate calculation methodology, and then metered and compensated appropriately.[26]

For energy storage, some combination of program rules, interconnection configurations, and performance monitoring would be needed to isolate the battery to solar-only charging. Under a simplified, bundled VOS rate, a battery is unlikely to produce an economic arbitrage scenario for providing dispatchable capacity that is worth the incremental cost in the near term. But if the VOS rate included time-of-day or critical-peak capacity performance bonuses, it could become economic in the future.

Other configurations may also enhance overall system performance. A solar project's design can influence the potential value streams by orienting panels toward the west to coincide with peak system demand. Another configuration that is becoming more common, would be to oversize the array relative to the inverter size to increase the delivered capacity and overall performance. Under a bundled, all-energy VOS rate, this would not be compensated, but if a VOS rate was unbundled and capacity was a separate line item, program designers may want to consider this potential design.

Interconnection

Interconnection and safety issues will likely be defined in the utility's standard interconnection process, outside of the VOS program. Similarly, high penetration scenarios on individual distribution feeders are largely handled and defined by interconnection processes, not the VOS program. There may be reasons to adjust the VOS rate based on high penetration congestion (discussed later under "rate treatment"), but the technical interconnection components are distinct from the VOS program. Utilities and/or states should review the interconnection requirements to ensure compatibility.

[26] One could also envision the packaging of generation and consumption capabilities, such as a VOS and demand response to critical system capacity needs. They probably will remain separated from a program design standpoint, but their presentation and packaging to consumers may be related, and their program impacts on the other could be considered together, if not coordinated.

Table 7 shows an overview of the VOS program design elements described above.

Table 7. Summary of VOS Program Design Options

Category	Options (The options under each category are not mutually exclusive)
Eligible participants	Residential and small business (or other energy-only rate customers) Non-residential (any demand-charge customer) Third-party on customer sites Third-party on brownfield or greenfield sites
Individual project size	No limit Sized by customer or participant type Expected generation relative to historical customer use Solar capacity relative to historical customer peak load (e.g., 100% or 120%)
Aggregate program size	No limits Total program capacity Annual budgetary expenditures Relative to utility demand or demand growth
Technologies	Flat panel PV Concentrating PV Micro-concentrating solar power (CSP)
Supporting technologies or installation configurations	Smart inverter Energy storage Panel orientation, tracking, or array: inverter ratios
Interconnection	Engineering and safety standards on the distribution grid are distinct from the VOS program, though it might make sense to tightly coordinate and communicate between the two (unless interconnection standards do not exist)

Text Box 2. Design Application: Installation Details

Table 8 outlines the different approaches each hypothetical utility took regarding the installation details, given their respective goals on eligible participants (e.g., residential-only versus all customers) and supporting technologies for Utility B (e.g., smart inverters for larger systems in anticipation of future grid integration interests). Other differing categories, such as project size and performance assurances, are less goal-related and indicative of natural decision leading to differences across organizations. Neither utility opted to limit aggregate program size, though Utility A's program will naturally slow if price-support funding runs out since projects would be uneconomic.

Table 8. Summary of Installation Details Application by Hypothetical Utilities

Category	Utility A	Utility B
Eligible Participants	Residential only Load-only	All Customer Classes Load-only
Individual project size	≤ 120% peak load	≤ 100% average annual consumption
Aggregate program size	No limit other than annual incentive budget; program continues without incentives	No limit
Technologies	PV only	PV only
Supporting Technologies or System Configurations	None	Require smart inverters for systems over 10 kW Provide a supplemental rate for W-SW facing systems
Performance	Eligible equipment lists	Eligible equipment lists On-site inspections for systems over 10 kW
Interconnection	NA	NA

5.3 VOS Rate and Contract Treatment

Automatic adjustments to the VOS rate and eligibility criteria can be incorporated into the program design decision process in a variety of ways. This section focuses on the underlying VOS program structure, automatic rate adjustment, and how the rate may be treated over time.

VOS Program Structure

As discussed in Section 3.1, the VOS program could be designed as a buy-all, sell-all program, where the consumer purchases all electricity consumed at one rate and sells all solar generation at the VOS rate. This design is used by Austin Energy and is proposed in Minnesota, where it is called a "full transaction." One attraction of the buy-all, sell-all design is that, if a utility wants to purchase solar to address customer preferences or its own policy requirements, a properly designed VOS program can address some key concerns with existing purchasing mechanisms, such as net metering. Under the buy-all, sell-all design, electricity purchases are decoupled from solar payments and each customer pays for the utility services he or she uses. And as long as the VOS rate includes the cost of solar power integration and fixed T&D costs to the utility, there is less likelihood of revenue erosion or cross-subsidization between solar and non-solar customers as a result of growth in distributed solar.

Alternatively, a VOS tariff can be designed to create a net excess transaction, where customers offset their own consumption with self-generated power before selling the net excess generation to the utility at the VOS rate (Keyes and Rábago 2013; Starrs 2014). This could be considered a hybridized approach between net metering and a VOS tariff. In this structure, the utility would provide a kWh bill credit for solar generation that meets the customer needs, either as it is produced or over a defined time period, such as monthly or annually, just like net metering. For any net excess generation, the VOS tariff would be applied for financial compensation ("buy-net, sell-net"). The self-generator is able to hold on to the RECs or sell them to the utility or another market participant.

There are some potential downsides to the net excess program design. First, since it does not separate the solar customers' purchase of electricity from the sale of their solar generation, this design does not necessarily address the cross-subsidy and cost-recovery issue that has sometimes been attributed to net metering (Kind 2013). In addition, in certain markets, the net excess approach could result in higher program costs than the buy-all sell-all design. If the total cost of PV systems is not competitive with retail rates, which is likely in the near term in many locations, the incremental incentive needed for a system to be economic may be larger than under the buy-all sell-all design. This is because the additional incentive is applied to a smaller portion of the power generated by a solar system (i.e., the net excess). Furthermore, if the utility wants to use distributed generation systems in its jurisdiction to meet RPS requirements (e.g., solar or DG set-asides), but is only able to purchase RECs associated with the net excess generation of each system, it would end up purchasing RECs from a greater number of systems. Incentivizing a larger number of systems in order to meet RPS requirements would add program cost if the solar systems are not yet price-competitive.

Another variation in the way VOS rates are applied is related to the side of the meter on which the PV system is located. The solar system could be connected on the customer side of the meter. In this case, solar generation is metered, the VOS rate is applied to this generation, and the customers receive financial credit on their bills. Austin Energy's program is structured this way for a variety of reasons. Remaining on the customer side of the meter requires no changes to existing interconnection procedures and policies, requires minimal solar industry or customer education (e.g., interconnection processes are not revised), and prevents the customer from receiving a taxable revenue stream since it mimics net metering. Again, when located on the customer side, both buy-all sell-all and net excess generation transactions would work. Under either structure it may be important to consider the total costs of solar integration onto the system and the fixed T&D costs to keep the utility whole.

The solar generation can also be metered on the utility side of the meter, and the transaction may be completely separate from the consumption and customer billing process. In this case, the utility can provide a check to the customer to pay for his or her generation. The legality of this structure may need to be evaluated for particular jurisdictions to assess whether it is in accordance with existing regulations. The possibility of providing an electric bill credit may be possible, but must also be investigated further. Notably, locating a system on the utility side of the meter likely limits the program design to a buy-all, sell-all transaction. Other challenges to this structure include: it would create a taxable revenue stream for the customer that would need to be reported to the IRS, and interconnection procedures would need to be revised, which might add confusion to the installation and program participation.

Other structural variations may also exist and could be considered.

Number and Kind of VOS Rates

The majority of this section, and the program design decisions succeeding it, are predicated on two critical decisions. The first is the number of VOS rates a program might incorporate. There are dozens of variables outlined below that could create a menu of rates for consumers to utilize– different rates by the location or performance capabilities of any particular solar system. The easiest option, from the standpoint of operation may be a single rate across the entire VOS program, but some of the ideas presented below offer enough value to consider applying more than one rate. Another option is the creation of adders to the VOS rate to encourage customer behavior such as encouraging system placement in desirable locations or the deployment of value-added elements such as storage. This adder could be applied on top of a single VOS rate.

In theory, there could be a submenu of value components that are all priced separately, and the utility or customer could sell or purchase them individually.[27] Unbundling the pricing of solar value components may be driven by competition (i.e., the availability of more economic options for the supply of the components). The most likely component for unbundling is environmental attributes, whereby the customer might keep such green attributes as renewable energy or carbon credits and sell only the primary electricity components. Other components may be defined for voltage control or other grid support services that can be provided by storage or smart inverter functions associated with a distributed solar system. Certain customers, such as a corporation with carbon mitigation goals or a broker selling RECs into an established REC market, may make more use of such unbundled pricing schedules than residential customers.[28]

A bundled VOS rate and the option to unbundle the rate into separate components increases the complexity of the VOS program design and administration. The limited experience of utilities with VOS programs to date in Austin, Texas and Minnesota has indicated an avoidance of both of these options in favor of keeping a single, bundled rate. As more experience is gained, the concepts of bundled rates and separating components may be worth assessing to see if they help meet VOS rate design goals.

[27] This concept is akin to the potential future of unbundled rates for electricity consumption in which some electricity components are separately purchased. For example, a home with on-site battery storage may not need firm capacity from the utility, and avoids a demand charge, but may need ongoing energy to charge the storage and to provide emergency backup power.

[28] REC ownership appropriation under net metering varied significantly across states from utility-owned to customer-owned to a hybrid approach, sometimes differentiated based on whether an incentive was provided by the utility. Under a VOS mechanism, a similar determination will need to be made. If an environmental value is included in the VOS rate, this is a strong indicator that the utility is purchasing the RECs from the generator in the transaction. The contract likely will make ownership explicit, whether bundled or otherwise.

Future Value (or Cost) Components

A VOS program could also be designed to be flexible, with a built-in option to reconsider the value or cost components and the opportunity to add or subtract components in the future. In order to assure investors that the VOS rate will not vary substantially more or less every year, the intentions of these updates should be made clear prior to execution. For example, the use of smart inverters to provide distributed grid support, such as voltage and VAR power support, may become more common, and a new component associated with this value may become desirable.

In a similar vein, variable generation integration costs could potentially increase in areas with high deployment. Smart inverter and battery operations could also be optimized to provide targeted value to the electricity system and system operator or owner. How these technologies translate into the VOS price signal and rate structure can get complicated quickly. Considerations include how these new costs and benefits are valued, whether the components are considered to be a new add-on to the existing VOS rate or whether the rate is updated, and the timeframe during which these changes will occur. It is important to balance the countering complexities that would be introduced by these changes, and to consider the potential impacts on capital availability (i.e., increased risk to the investor likely will increase the cost of capital and could decrease the number of investors).

Rate and Contract Adjustments over Time

The VOS rate components (i.e., energy, capacity, etc.) are calculated and set at a distinct point in time. Some of the components are monetized in real-time as solar is generated (e.g., energy), while others have a lag in realizing the real dollars saved (e.g., infrastructure deferral). In utilizing bundled VOS rates, the utility is paying for all value up front. In theory, unbundled rates would offer the capability to pay varying components based on the realized dollars at varying points in time. Practically, this would likely prove excessively complex and costly on the administrative side. It could also discourage investment by third-party investors who require greater certainty in their returns.

The VOS component values can also be recalculated at various intervals based on updated analysis. The frequency of the update could have up- or down-side costs for the utility or the participant. For example, Austin Energy's VOS rate was set at 12.8 ¢/kWh in 2012 when it was first enacted, but fell to 10.7 ¢/kWh in 2014 based on natural gas price changes, but the trend could go the other direction just as easily based on category cost factors (CPR 2013). Financing a solar installation under this design could prove more difficult due to the potential variability and associated uncertainty, neither of which are favored by investors.

The VOS rate can be levelized (reflecting the long-term value of the resource addition as a fixed value over time) or annualized (showing annual changes in value over time) based on, for example, anticipated system performance and the discount rate. The high-case VOS rate could be fixed at 11 ¢/kWh over 20 years on a levelized basis. Alternatively, the rate could start at 7 ¢/kWh in Year 1 and escalate to 18 ¢/kWh in Year 20, for example, and be equal with regards to the net present value basis (Figure 8). A contract could still range from one to twenty years with these varying payment structures written into the contract. Over long-term contracts, there are other options, such as front-loading, that represent the same real-dollar amount.

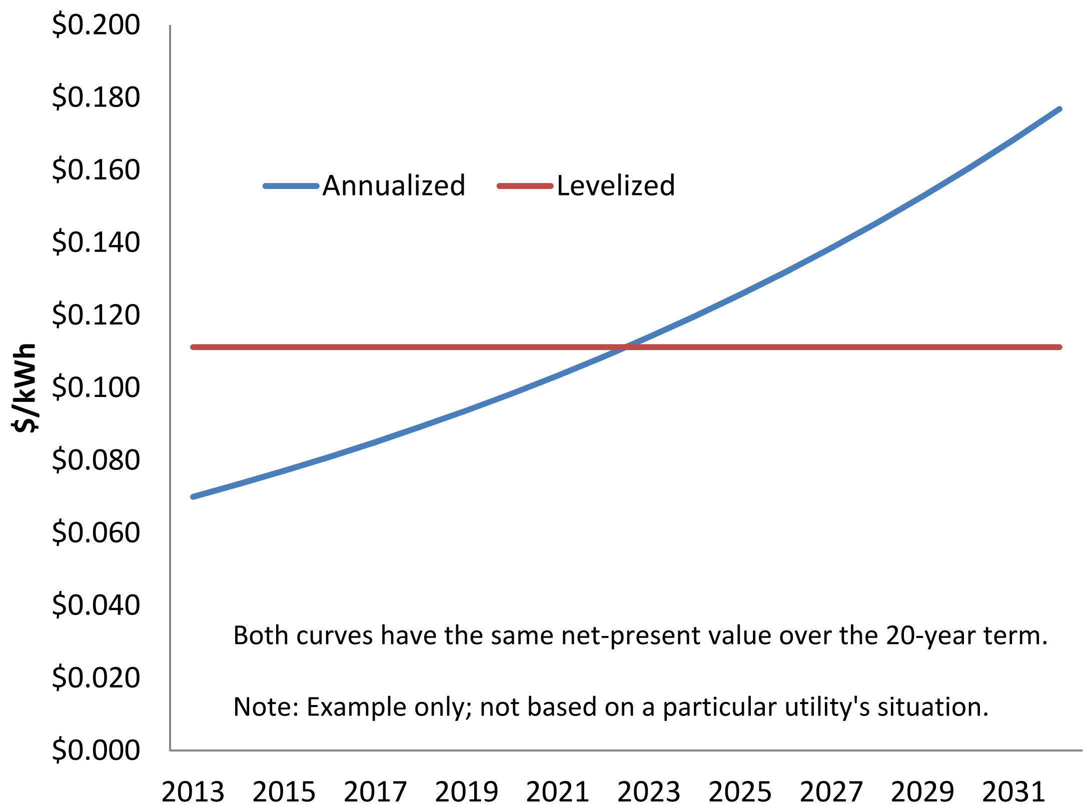


Figure 8. Example of annualized versus levelized VOS rate

Whether the VOS rate update is applied to existing participants or only to new participants depends on the contract period and terms used. For practicality, customer contracts could be set to match the frequency of the VOS rate updates (short duration). Alternatively, the contract could match the expected life of the PV installation. Developing a fixed VOS rate over a 20-year period would create a class cohort of participants ("2014 vintage") and a portfolio of contracts at varying parameters. Shorter update periods would more accurately reflect the actual value to the utility system by removing the long-term uncertainty of modeling assumptions and distributing the risk between the utility and the participant. While shorter valuation periods create more technically accurate values, longer contracts lessen the unknowns to the participant and the project investor because the utility takes on greater risk. Participants and their investors likely prefer longer contract periods that lock a customer into a 'vintage' of a VOS rate since this reduces uncertainty that can translate into predictable costs, particularly with project financing. However, over such long time periods, market conditions and the actual VOS realized can change drastically. Austin Energy and the Minnesota process represent the bookends of these decisions, the former varying annually and the latter fixed for 25 years. An alternative between the extremes would be medium term contract intervals, such as five or ten years; a medium term may balance the risk between customers, utilities, and market uncertainty.

Rate Differentiation Options

The limited experience to date includes a single, bundled rate for all eligible participants, showing a preference for a basic, streamlined VOS rate design. However, numerous options could include the development of two or more rates based on localized factors that materially impact the costs or benefits of the value categories. Historical FIT design created different rates based on solar installations costs (Couture et al. 2010; EIA 2013b). Larger solar system owners enjoyed economies of scale and were typically offered lower FIT rates than residential systems, while ground-mounted systems were offered lower FIT rates due to lower presumed installation costs than roof-mounted systems. The goal of this policy design is to make the rate of return consistent across a variety of project sizes and locations.

In a VOS construct, differentiation among rates might make sense if these differences are based on issues that materially change the value of the solar energy to either the utility system or to society. This means that roof-mounted versus ground-mounted systems or ownership types are likely immaterial to the value proposition. However, PV located in electrically congested urban centers is likely more valuable than PV in less constrained suburban areas. A utility could give differentiated VOS rates for different ownership types, but that decision would need to be justified through calculated value or cost differences. Some of the indirect installation details could be included as part of eligibility criteria, rather than being managed through differentiated rates.

One option that likely does influence VOS categories is the time of performance, which could be either intraday, daily, or seasonally. A utility's costs of energy, capacity, or other components vary by the time of delivery. In a similar fashion, system configurations like panel tilt or azimuth, and whether tracking mechanisms are utilized, are actually proxies for intraday performance characteristics related to energy and capacity benefits that vary based on time. However, the benefits (from an alternative VOS rate) that a customer receives for solar system configurations that sync performance with the utility system would need to compensate for any potential loss in revenue caused by reduced system performance. If a PV system will lose 5% in annual performance and gain only 2% from an alternative VOS rate, it may not warrant changing the system configuration.

Program design might also look at locational differences beyond a single, system-wide price. For example, regional price differences might exist across wholesale locational marginal pricing nodes that may change the energy value. In a similar fashion, certain regions or even distribution feeders may have different amounts of solar penetration or demand patterns that increase costs or value based on locational or other characteristics.

To reiterate, creating multiple or unbundled VOS rates based on different value or cost streams to the utility system is certainly possible. However, the benefit of more technically accurate and granular information may be balanced against the administrative costs of calculating and managing more complex programs, as well as communicating the program complexities to consumers. Cost or value sensitivity analyses could be performed on the candidate design options to assess the magnitude of change and then applied to likely consumer behavior based on the value spread.

The summary of the VOS rate options is shown in Table 9 below.

Table 9. Summary of VOS Rate and Contract Options

Category	Options
VOS structure	• Buy all electricity for consumption, sell all solar generation under VOS tariff • Buy net electricity for consumption, sell net excess solar generation under VOS tariff
Number and kind of rates	• Single or multiple, bundled rates • Single or multiple, unbundled rates
Future VOS categories	• Consider future new value or cost categories, calculation, management and transition
Adjustments over time	• Compensating unbundled VOS categories at different points in time • Levelization versus annualization of the VOS rate in the customer transaction • Frequency of recalculating the VOS rate • Length of contract • Present value of the contract
Time of generation	• Time of day • Daily • Seasonal • Panel orientation • Fixed versus tracking capabilities
Locational differences	• Single, system-wide price • Regional price variation based on utility costs or value (i.e., congestion) • Individual, types or categories of distribution feeder pricing
Indirect value options	• Customer segments • Rate tariff types (demand, three-phase, etc.) • Solar project size • Ownership type (customer, third-party, etc.) • On-site location (roof, ground, etc.)

Text Box 3. Design Application: Rate and Contract Treatment

Utility B decided to utilize PV systems as generating capacity tools by using multiple rates for both time of day performance and smart inverter control capabilities—while recognizing that optimal implementation will not be realized on day one. Utility A kept things simple, employing one rate, but added a bonus VOS category for distribution grid congestion relief areas, which may change over time (hence, creating a flexible adder and not a permanent rate). Each utility took a different approach on contract period (5 or 20 years) and how frequently the VOS rate is updated (annually versus a typical 2-3-year cycle with integrated resource planned). Both use a levelized rate, but Utility B also included an inflation adjustment.

Table 10. Summary of Rate and Contract Application by Hypothetical Utilities

Category	Utility A	Utility B
Number and kind of rates	Single, bundled rate	Multiple, bundled rates * Standard rate * W-SW rate * Smart inverter rate
Future VOS categories	NA	Consider how VAR, voltage, and curtailment adders could be implemented in a future VOS tariff
Adjustments over time	Levelized, 20 year contract Updated with IRP cycle	Inflation adjusted, levelized, 5-year contract Updated annually
Time of performance	NA	Capacity value for projects that are oriented at 225-270 degrees
Locational differences	10% VOS bonus on feeders that need generation/congestion relief (highlighted on website)	NA
Indirect value options	NA	NA

5.4 Potential Additional Price Support

Based on the previous analysis of the potential differentials between the VOS rate and the LCOE-PV, many locations currently will be in price-support markets where the VOS is less than the LCOE-PV. If one of the program goals is to sustain existing markets or create new solar market activity, an additional incentive of some kind may be necessary.

Why would a utility want to offer an incentive in addition to the VOS tariff?

- Provide solar market stability in transition from NEM to the VOS mechanism
- Provide a multi-year transition to an incentive-free VOS rate
- Adopt a compromise position with stakeholders during the transition to a VOS program

- Provide an explicit incentive amount on top of the VOS rate that is transparent to all stakeholders.

Obviously, a transition incentive represents one option, and the details of whether and how to offer an incentive depends on the solar and utility market conditions, the state policy and regulatory conditions, the nature of the utility's relationship with stakeholders, and the short- versus long-term goals of the transition process.

Assuming there are compelling reasons to add transitional price supports to a VOS rate, the goal of rebates or production incentives over a multi-year transition period might be to fill the gap between the VOS and LCOE-PV. There is a long programmatic and research history of incentive programs, and this report will not reiterate all of the options and best practices in incentive program design.[29] Generally speaking, the incentive program could be structured to encourage cost reductions and efficiencies in solar installations over time, much like California's incentive programs did with both their performance and rebate incentives. However, a number of incentive categories do deserve further discussion in the context of a VOS program.

Incentive Benchmark

If a jurisdiction decides to transition from its current policy construct to a VOS policy, that transition will have the greatest chance of success if it is carefully structured and clearly conveyed in advance. Setting the initial incentive to complement the VOS rate will require a target benchmark, which can be determined using a variety of approaches.

First, the benchmark can be a recreation of the NEM *status quo*, either relative to the LCOE-PV or an alternative measurement like retail rates. Using either can create nuances in design that could be weighed and considered with earlier decisions regarding eligibility or payment amounts. Setting the incentive to recreate the NEM *status quo* means different things to different customers. The VOS could be higher than retail energy rates for commercial customers but lower than the LCOE-PV, improving market conditions for this segment (compared to what was offered under NEM). For residential customers, the VOS is more likely to be below both retail rates and LCOE-PV. If the goal was to recreate the NEM financial *status quo*, the commercial customers may not need an additional incentive, but residential customers could. However, if the incentive was benchmarked against the LCOE-PV and both customer segments were eligible, an incentive might be calculated as necessary, but at different payment levels for residential versus commercial customers. Note that this implies that although the VOS rate may not be differentiated by size or customer type, the incentive amount may be, depending on the utility's transition goal and VOS program rules.

In addition, if the benchmark is the LCOE-PV, the incentive level may consider known and unknown federal and state policies that may change in the future, such as the federal ITC. The ITC drops from 30% to 10% for commercial and third-party residential installations and to 0% for customer-owned residential installations on January 1, 2017 (DSIRE 2014a). If the NEM *status quo* was used as the benchmark, the incentive program is not tied to external market changes that would occur regardless of the NEM-VOS transition.

[29] Notable papers for incentive program design reference include Bird, Reger, and Heeter (2012) and Couture et al. (2010) (Table ES-1 in particular).

Incentive Type

The incentive itself also could be structured as either a performance incentive (¢/kWh) or capacity incentive ($/W or % costs). In order to compare the two and understand the potential value, the capacity incentive could be converted by program administrators into a net present value in ¢/kWh (in practice it would be administered using the capacity structure).

Historically, incentives consisted of a one-time upfront payment, such as a $2/W rebate, a payment based on actual performance over a fixed time period, such as a 10 ¢/kWh for 5 years, or a below-market interest loan or buy-down, such as reducing a solar loan rate from 5% to 2.5%. Outside of the VOS conversation, rebates were initially popular with utility and state program managers in the 2000's, especially with the residential segment. But performance incentives have increased in popularity at the commercial and, increasingly, residential scale. Performance incentives appeal to program managers because funds are only dispersed for actual solar production, but there are higher transaction costs in meter reading, billing, and payments. In the context of VOS, performance incentives probably align more easily with the VOS rate, both being paid per kWh.

Incentive Reductions

Once the initial incentive is set, there are a variety of ways to both trigger a reduction and to determine the amount of the reduction. These methods parallel past incentive program experience and include market targets such as installed amounts of capacity (e.g. California Solar Initiative), achieving certain metrics on the LCOE-PV or the installed price, or alternatively, simply stepping down a certain amount at fixed time intervals. Time intervals provide predictability, but if the market shifts more rapidly than planned, such as through a rapid solar panel cost reduction period, incentives may be larger than needed to encourage new projects. Using capacity as the metric will step the incentive down once a pre-determined amount of capacity is installed, and will change more quickly if the installations are more rapid than anticipated.

The goals are to aim for transparency and predictability and to include sufficient lead times for the solar industry to adjust. Depending on the benchmark, it will be important to the solar industry to have a standard, defined method and readily available data sources that can be used to calculate the initial and future incentives. A summary of VOS incentive options is shown in Table 11.

Table 11. Summary of VOS Incentive Options

Category	Options
Incentive benchmark	• Equivalent to pre-VOS NEM financial *status quo* • LCOE-PV benchmark • Plan for non-VOS market changes, such as federal or state policy (if known)
Incentive type	• Upfront payment ($/W) • Performance-based incentive (¢/kWh) • Below market interest loan or buy-down
Incentive reductions	• Aim for transparency and predictability with lead times • Reduce incentives based on achieving a certain LCOE-PV, installed capacity, installed price, known time periods • Reductions can occur in percentage, whole number, or other bases • Adjustments can be made on pre-determined schedule or certain number of days following event (announcement, approval, etc.)
Incentive differentiation	• Project size • Customer segment • Technology • Time of delivery

Text Box 4. Design Application: Price Support

Utility A is in a price-support market, and therefore utilized an incentive through an upfront rebate. Utility B does not require an incentive because it is in a price-competitive market. Utility A opted to calculate the incentive such that the NEM-to-VOS transition should have no net effect on the pre-VOS localized market activity, but planned for quarterly adjustments as prices or non-utility incentives change. The rebate is calculated as the present value (PV) of the summed difference between the VOS tariff and the LCOE-PV over 20 years of performance (the present value of the difference between the VOS tariff and the LCOE multiplied by the annual production of the system over the 20 year term of the program). To manage unexpected price declines, the incentive is capped at a percentage of installed costs. The utility will need to plan for the large change in required incentives if the federal ITC is not renewed and for the transition period when the VOS tariff approaches the LCOE-PV, and decide whether to increase the incentive to fill the gap and maintain market growth targets.

Table 12. Summary of Price-support Application by Hypothetical Utilities

Category	Utility A	Utility B
Incentive benchmark	Incentive required to generate market for 20 MW of installations, which was the pre-VOS activity	No incentive required
Incentive type	Rebate	NA
Incentive reductions	Modify incentive level quarterly based on forecast targets for annual market growth of 15% until VOS tariff reaches LCOE-PV	NA
Incentive differentiation	Incentive capped at % of installed costs	NA

5.5 Administrative Issues

There are a number of administrative issues that can position a VOS program for success, and they are best considered as the program is built and deployed. These include a transition plan, accounting issues, and stakeholder engagement.

VOS Transition Plan

Transitioning from a current solar tariff rate (most likely NEM) to a VOS rate would require advanced planning, both internally within the utility and externally with stakeholders.

Contracts and Materials

A VOS program contract could be developed that outlines the product being purchased as well as pricing structure, contract length, and other details. Existing power purchase agreements and portions of the NEM contract—as well as external examples from other VOS or feed-in tariff programs—could provide a basis for developing the contract. Historically, length and complexity of NEM contracts and interconnection agreements have been a barrier to participation and a point of contention for some solar stakeholders. This concern could be addressed through the design of the VOS program contract process. Doing so could reduce the possibility of potential participants feeling intimidated or overwhelmed by the more technical and complex contract document. It could also help reduce the transaction costs of explaining and answering questions about the contract to hundreds—or even thousands—of potential participants.

In a similar fashion, interconnection agreements may need to be updated if the point of interconnection changes from the customer to the utility side of the meter. This may also lead to changes in interconnection requirements and the way interconnection requests are processed within the utility. Proposed changes to existing interconnection policies may also create the need for additional dialogue between the utility and the solar industry.

Communications

The utility may want to consider communicating with separate audiences during the transition period:

1. **Customers**: The website, call center scripts, and other materials likely will be updated to communicate the program changes. Especially in the case of residential rooftop solar customers, simplicity and transparency in VOS program implementation may be crucial.
2. **Solar industry**: The solar industry may desire more detailed information on program details or training through workshops, presentations, or other outreach events. Time spent upfront on education will likely pay dividends in reduced customer service due to confusion and fewer program material revisions.
3. **Public notice**: New electric rates sometimes require public notice through billing inserts, public meetings, or other means of communication.

New program marketing materials could be developed to support these communication efforts. The utility could consider reviewing all existing materials, print or online, to remove legacy references or materials to NEM.

Timing

Depending on the level of stakeholder involvement, regulatory process, or public notification requirements, the program may or may not be well advertised outside of the utility. The program can be implemented over a variety of time periods, and can become available for participant registration either immediately or on an announced date in the future. A defined transition plan to the new VOS program could be clearly laid out, but may represent a complete switch from NEM to a VOS mechanism, or the two programs could run in parallel during a transition period or even on a permanent basis.

Cost Accounting

While the VOS rate is determined based on the benefits of distributed solar to the utility, there are a variety of costs to be allocated and accounted. They fall into two general categories, addressed below.

Administrative and Management Costs

Typically, administrative and management costs are rolled into normal utility business accounting unless the utility has a renewable energy cost recovery adjustor. In theory, the program administrative costs could be initially estimated and later calculated and subtracted from the VOS rate. However, this method would be atypical of normal electric utility accounting practices, in which similar costs are socialized across all ratepayers.

Interconnection and Metering

Interconnection and metering costs may be based on legacy NEM practices to allocate costs between the utility and the solar developer. If the interconnection point or process substantially changes because of the change to VOS, such as new code, metering changes, performance monitoring, or study requirements on the utility side of the meter, these costs could be revisited to determine the appropriate costs and benefits. For example, the base requirements for solar metering may be the responsibility of the customer, but any enhanced or upgraded costs for a more sophisticated meter or communication based on the VOS tariff may be the responsibility of the utility. This is one example – there are many other variations that could be considered.

Stakeholder Interests

Stakeholders will approach a VOS program from different perspectives; each will have unique objectives driven by their organization's needs. Table 2 listed the objectives and concerns for a wide variety of stakeholders, including the utility, PV generating customers, non-solar customers, policy makers, the solar industry, and society. That table focuses specifically on policy goals and concerns. Four main VOS policy themes emerged: 1) pay the utility sufficient revenues for grid services provided to support solar growth, 2) recognize the VOS benefits and costs, and compensate the project owner appropriately, 3) limit cost to customers, both those with solar and those without, and 4) create a transparent VOS rate calculation methodology. These themes could be used not only as policy goals, but also policy design principles.

The approach to program design and the transition implementation may include internal decisions specific to the utility, as well as broader decisions made collaboratively with customers, the industry, and other stakeholders. Some elements may take effect immediately while others may be transitioned in over a predetermined timeframe. Utilities and other decision makers[30] will need to assess the approaches taken and recognize both the technical and political nature of key design elements in order to select the most appropriate approach for each decision point.

Understanding core stakeholder interests and cross checking design decisions against them is an important approach to predicting reactions and guiding design in order to achieve desired outcomes. An obvious example is a scenario in which a utility is implementing a VOS tariff that is significantly lower than the *status quo* net metering retail rate, and then announcing finalized program rules without industry or consumer consultation. Clearly, there may be negative reactions in this situation.

In the end, each jurisdiction will need to determine which stakeholder-driven policy goals will influence VOS policy design principles and how. Most importantly, each stakeholder group involved in formulating a VOS program can voice their opinions to help prioritize its design

[30] "Decision makers" refers to state commissions regulating investor-owned utilities, city councils overseeing municipal utilities, boards of directors overseeing cooperative utilities or public utility districts, or similar authorizing jurisdictions.

principles to make sure the most important goals are adequately addressed. Thus, it is critical to consider stakeholder interests both when deciding on policy goals and also during the policy design phase. Table 13 summarizes VOS administrative issues.

Table 13. Summary of VOS Administrative Issues

Issue	Options
Transition plan	• Contracts and materials would be developed for VOS tariffs • Create communications plan to serve varying audiences • VOS program can be implemented immediately or over time, potentially in parallel with the NEM program on a transitional or permanent basis
Interconnection - side of the meter	• Customer side of the meter • Utility side of the meter
Interconnection and administrative cost accounting	• Administrative costs are likely to be spread across all ratepayers barring precedent or regulatory decisions otherwise • Interconnection and metering costs can follow existing allocation practices unless there are material changes in requirements, process, and costs
Stakeholder engagement	• Stakeholder interests across the utility, solar industry, and regulatory communities will be different and can be assessed together • Engaging openly and early during the VOS program design process will enhance transparency

Text Box 4. Design Application: Administrative Issues

Utility A and B both planned for a 6 month transition plan, but took a different approach to existing PV systems. Utility A plans to move all customers to the VOS rate, but created a one-year process for existing solar customers for education and adoption. Utility B is grandfathering existing NEM customers (who will stay on the NEM tariff). Both utilities also opted for interconnections for residential customers on the customer-side of the meter and to provide bill credit (not kWh credit), to avoid taxable income for customers. This simplifies some of the transition needs because interconnection requirements, billing arrangements, installer education needs, etc. mimic NEM processes. Utility B did differentiate between larger systems by interconnecting on the utility-side of the meter in order to align with its intention of owning the smart inverters. This unique arrangement will require deeper thought and engagement within the utility and with the solar stakeholder community on costs, risks, and liabilities; hence Utility B is forming a stakeholder working group to discuss and address these issues. Related, Utility B is covering interconnection and metering costs, while Utility A customer pays a flat interconnection fee. Administrative costs for Utility A are subtracted for the VOS rate to recover them, while Utility B absorbs the costs internally.

Table 14. Summary of Administrative Issues Application by Hypothetical Utilities

Issue	Utility A	Utility B
Transition plan	6-month notice Applies to all customers Existing NEM customers given 1-year transitional period with bill comparisons	6-month notice Grandfathering existing NEM customers
Interconnection – side of the meter	Customer side of the meter All transactions are a bill credit	Utility side of the meter > 10 kW Customer side of the meter < 10 kW All transactions are a bill credit
Interconnection and administration cost accounting	Customer pays flat interconnection fee Other programmatic administrative costs are subtracted from the VOS rate calculation	Utility owns smart inverters Utility pays for interconnection and metering costs
Stakeholder engagement	Utility develops proposal and incorporates stakeholder comments	Stakeholder working group actively develops plan over 6-month period

6 Analysis Synthesis

The success of VOS tariff implementation will be as dependent upon the program design and structure as it will be on the VOS tariff calculation itself. After providing some key background about the policy, how it relates to existing policies, and the implications of a VOS program for current incentive structures, this report explored various considerations in VOS program design, the implications of the variety of choices, and the potential impact of some of the major components. In the end, jurisdiction-specific input assumptions and market considerations will factor into the design and tariff calculations of a VOS tariff program. While this report does not address the details of any one jurisdiction-level program design, it does help frame the broader decisions and implications that require deliberation.

Specific lessons learned from the existing VOS program in Austin, Texas as well as the VOS policy under development in Minnesota include:

1. Stakeholder involvement and/or transparent VOS calculation methodologies are important for customer and regulator support
2. VOS rates can be an alternative to NEM; cross-subsidies can be addressed by decoupling payments for DGPV generation from the retail rates paid by the customers (e.g., "buy-all, sell all" transactions)
3. The VOS rate in addition to federal incentives are generally not sufficient to encourage additional solar deployment using incentives and electricity prices available today; an incremental solar incentive may be needed–although such a subsidy may be able to ramp down quickly if technology and installation costs continue to decline
4. Rate variability creates uncertainty. In order to create a self-sustaining market, it may be helpful to set a minimum rate as part of VOS tariff design.
5. Third-party solar leases may be compatible with a VOS tariff, if local rules allow
6. Customers can benefit from accumulated solar credits that can be rolled over indefinitely.

Effective VOS program design would encompass the nuts and bolts of how participants (e.g., customers, solar companies, project developers, etc.) access the VOS rate, answering questions such as:

1. What are the overall design philosophies, objectives, and tradeoffs between stakeholder interests?
2. What are the eligibility and installation rules and details for participation?
3. What are the rate and contract terms implemented for a long-term program?
4. Is the VOS rate sufficient to support solar development, given the current market and available incentives? Will a separate price-support mechanism be required to stimulate or sustain solar development?
5. How are stakeholders involved in program development input?
6. How might program design component change as the solar market changes?

Within the realm of program design, the authors explore four major design areas, and discuss a number of individual design considerations available under each, shown in Table 15:

Table 15. VOS Program Considerations

Installation Details	Rate Options	Incentive Options	Administrative Issues
• Eligible participants • Individual project size • Aggregate program size • Technologies • Supporting technologies or system configurations • Performance • Interconnection	• Number and kind of rates • Future VOS rate categories • Adjustments over time • Time of performance • Locational differences • Indirect value options	• Incentive benchmark • Incentive reductions • Incentive differentiation	• Transition plan • Accounting • Stakeholder engagement

Utilities can, to some extent, draw on experiences from managing other programs that support solar, including NEM programs and other incentive programs such as rebates. However, several areas are unique to the new market transaction structure that a VOS tariff represents. For the jurisdictions that have a combined goal of maintaining a robust solar market and that moves solar from a position of price-support to price-competitive, VOS program designs will require sufficient flexibility to ensure that the utility can maintain market growth without paying more than required for sustained PV deployment.

In configuring a VOS tariff that benefits all stakeholders, decision makers may include some of the factors that have emerged in recent negotiations:

1. Compensating solar customers for generation from their systems and compensating utilities for solar-supporting grid services, while ensuring that utility revenue requirements are met,
2. Recognizing the VOS to the utility system and society,
3. Limiting costs to solar and non-solar customers,
4. Creating a transparent VOS calculation methodology.

A calculation was performed in order to compare a national-level average VOS tariff, with state-level LCOE-PV for each state, as shown in Figure 9. The goal of this high-level analysis was to determine how many markets in the United States are price-support markets (LCOE-PV > VOS tariff, where additional incentives are likely needed), transitional pre-economic markets (LCOE-PV ~ VOS tariff, where few incentives are likely needed), or price-competitive markets (LCOE-PV ≤ VOS tariff, where the VOS program design shifts away from incremental incentives). As shown in Figure 9, the combination of the VOS rate and the incremental incentive will determine whether the VOS rate, plus incentives, is high enough to cover the LCOE-PV, and encourage continuous distributed solar project development. For any particular jurisdiction moving ahead with a VOS rate and program, this calculation would need to be substantially refined to include those values relevant to the utility system and society (which could include generation value and environmental benefits), using local assumptions and an individualized calculation methodology This could occur through a public stakeholder process.

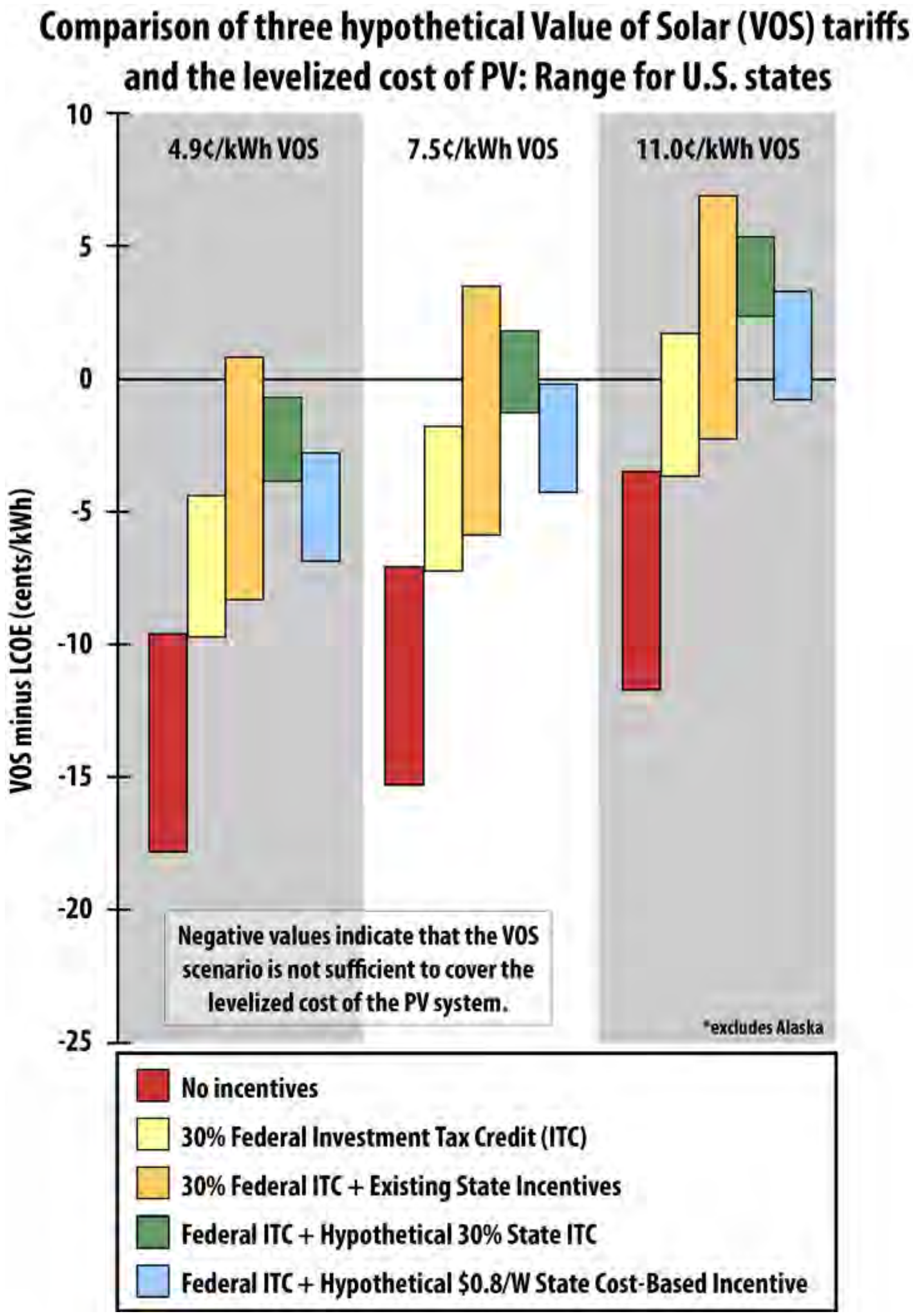


Figure 9. Comparison of VOS and LCOE-PV

Today's electricity markets have many more variables that impact the direction of market prices; as markets change dynamically over time and as new policies are investigated, policies that can account for both low and high DGPV penetrations will likely be sought out. With the costs of solar continuing to decline, VOS tariffs are expected to gain more attention as increasing levels of DGPV are deployed at higher penetrations. Given the diversity of markets, local methodologies for rate setting could vary extensively according to goals of decision makers (to encourage more solar growth or to simply value it), market conditions (non-economic, pre-economic, or grid-competitive), and other variables addressed in this report. Early feedback indicates that several key considerations can contribute to VOS program success, including thoughtfully considering new options, engaging stakeholders in discussions, laying out a path for transitioning from existing policies, limiting overall program costs, and creating transparent policy design and implementation. In the end, success will stem from a solid understanding of local market conditions, and how a new VOS policy can contribute to local policy objectives through thoughtful program design.

Appendix A. Select VOS Calculation Analyses to Date

Several studies have examined the VOS to date. Below are the key calculation structures and takeaways from a few of these analyses.

A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation

Keyes and Rábago 2013

This guidebook was published by the Interstate Renewable Energy Council (IREC) to 1) assess lessons learned from the calculation methodologies assessed by RMI in the first edition of its meta-study, and 2) propose to PUCs a standardized cost and benefits calculation methodology for DGPV. The authors point out that their proposed calculation methodology is needed because of the lack of consistency and (sometimes transparency). As summarized by IREC, in San Antonio and in Arizona, utility-led calculations were well below solar industry's estimates of the VOS. The IREC-proposed DGPV calculation methodology focuses on VOS that can be used by a variety of policies including NEM, VOS tariffs, fixed-rate feed-in tariffs, or incentive programs. It suggests some key considerations including:

1. **DG discount rate** based on inflation instead of the utility cost of capital
2. **Only consider DG exports to the grid** instead of total generation produced. Applied to VOS rates, this would mean on the net exported to the grid would receive the VOS rate
3. **Study timeframe** of 30 years--5 years longer than equipment manufacturers' warranties
4. **Utility load** is likely to be lower with behind-the-meter resources
5. **A range of DG market penetration** should be considered, including expected, high, and low
6. **Transparent input models** accessible to all stakeholders are important and non-disclosure agreements can be signed for data sharing sensitivities
7. Characterize the **broader geographical area** selected for the study to account for the range in local values
8. Consider **adjacent utility systems,** especially at DG penetrations above 10%
9. **Multiple perspectives of benefits and costs** should be considered, including utility rate impacts and societal benefits and costs
10. **Levelized approach** to estimate benefits and costs
11. **Utility-provided inputs,** both for current and future data could be required as input assumptions, including:
    A. 5-10 year price of natural gas
    B. Customer class-based hourly load shapes
    C. DG hourly production profiles
    D. Hourly line losses
    E. Capital cost, fixed and variable O&M for the utility's marginal units

i. Distribution system planning upgrade costs (capital, fixed and variable O&M)

ii. Individual distribution circuit hourly load data.

IREC suggests that there are several main components required to properly calculate a VOS rate, including:

- Avoided energy benefits
- System losses
- Avoided capacity
- T&D capacity
- Grid support (ancillary) services
- Financial services: fuel price hedge or guarantee
- Financial services: market price response
- Security services: reliability and resiliency
- Environmental services
- Social services: economic development.

In the end, IREC has three major conclusions that are likely to have the largest impact on the calculation of VOS rate:

1. Distributed solar generation (DSG) primarily offsets combined-cycle natural gas facilities, which can be reflected in avoided energy costs.
2. DSG installations are predictable and can be included in utility forecasts of capacity needs, so DSG can be credited with a capacity value upon interconnection.
3. The societal benefits of DSG policies, such as job growth, health benefits, and environmental benefits, can be included in valuations, as these were typically among the reasons for policy enactment in the first place.

Methods for Analyzing the Value of Distributed Photovoltaic Generation

Denholm et al. 2014

This report examines the variety of ways to estimate the value—the costs and benefits—of DGPV. Previous value estimates assumed low DGPV penetrations (and other aging assumptions); moreover, previous methods for valuation are becoming inadequate for analyzing today's electricity systems. First, existing methods for calculating DGPV value are assessed. The authors examine the input data assumptions, calculation methodologies and tools available to conduct VOS estimates, term by term. Next, how these methods could evolve with increasing DGPV is discussed—which could require improvements in data, tools, and transparency as well as a higher level of effort and expense. Finally, gaps in current value-analysis capabilities are identified. Methods for analyzing PV value were considered by E3 in California, CPR in Minnesota, and in RMI's second edition meta-study (Hansen, Lacy, and Glick 2013). The methods range from the simple (quick, inexpensive, and requiring basic or no tools) to the complex (time consuming, expensive, and requiring sophisticated tools) for each of seven VOS term categories:

- Energy
- Emissions
- T&D losses
- Generator capacity
- T&D capacity
- Ancillary services
- Other costs and benefits.

No single tool or method can capture the interactions among generators, distribution, transmission, and regional grid systems, or the effect of DGPV on the long-term generation mix and system stability requirements. However, it is possible to envision a “full” DGPV value study in which these interconnected elements are considered, shown in Figure 10 (Denholm et al. 2014).

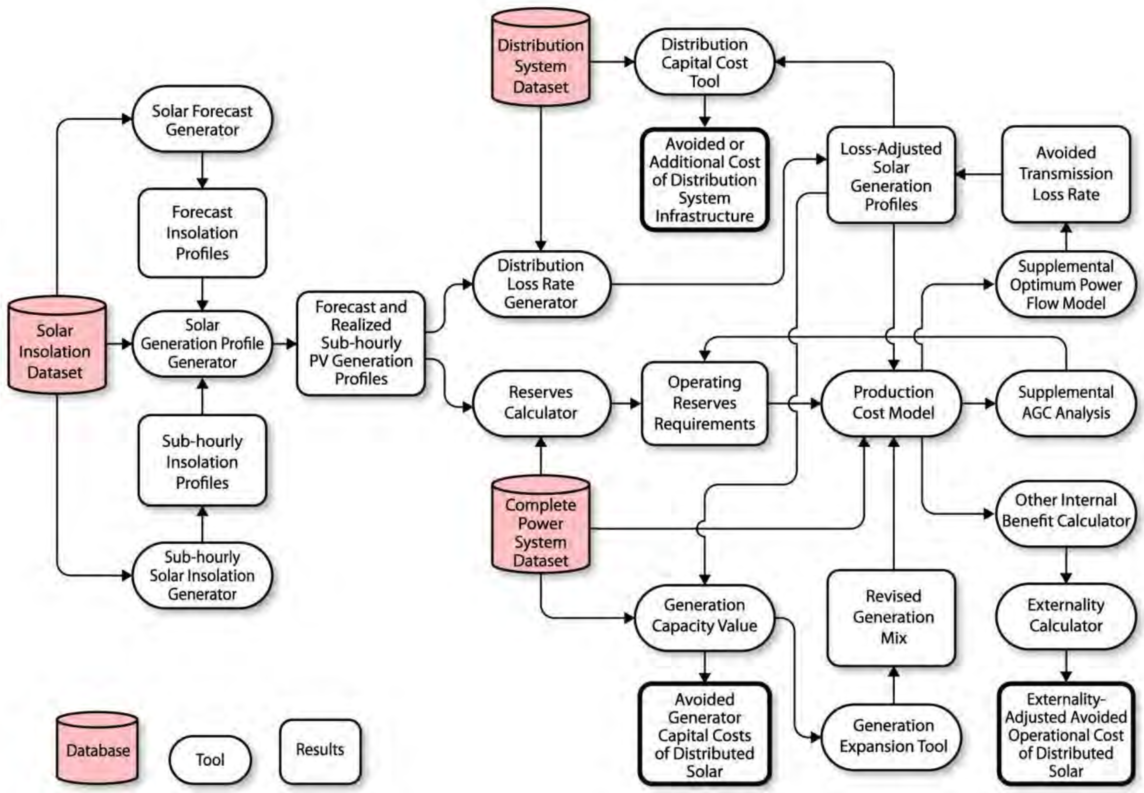


Figure 10. Possible flow of an integrated DGPV study

Source: Denholm et al. (2014)

A Review of Solar PV Benefit and Cost Studies: Second Edition

Hansen, Lacy, and Glick 2013

RMI created a meta-study that reviewed 16 DPV benefit/cost studies (circa 2005-2013) by utilities, national labs, and other organizations. This second edition added an examination of the 2013 Xcel study in Colorado. According to RMI, none of these studies was comprehensive –and several acknowledged that some benefits and costs could be difficult or impossible to quantify.

For most studies, the overall approach and terms to include in the analysis generally appear to be in agreement, but the calculation methodology for distribution system value, grid support services, and unmonetized terms (e.g., financial risk, environment, and social value) have less agreement. As further clarified in the document, “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 can be done with the understanding that results must be normalized for context, assumptions, or methodology” (Hansen, Lacy, and Glick 2013, p. 4). The results across all studies are shown in Figure 11.

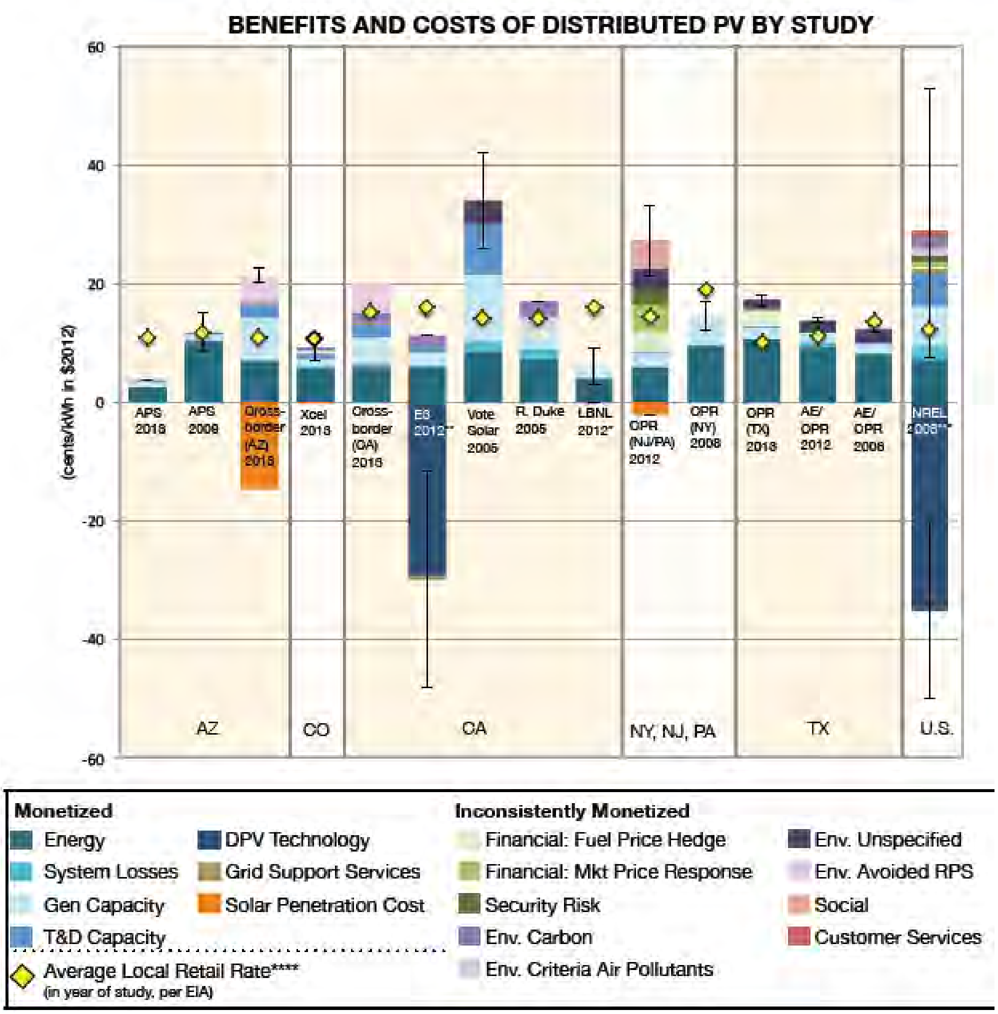


Figure 11. RMI meta-study: benefits and cost of distributed PV, by study

Original RMI Notes on the figure: *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, and not a research study. Customer Services, defined as the value to [the] 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).

Also Note: E3 2012 study not included in this chart because that study did not itemize results.

Source: Hansen, Lacy, and Glick (2013)

As shown, there are many different ways to perform VOS calculations. This is why it is critical for any jurisdiction contemplating a VOS policy to think about their prioritized policy goals so that the VOS program calculation and policy design can best achieve those objectives.

Appendix B. VOS Scenario Calculation Assumptions

Generic Assumptions

- Real discount rate – 7.5% (which leads to a nominal rate of 9.3%)
- Present value of accelerated depreciation – 78.4%
- Tax rate – 35% federal and 6% state
- Solar system life – 25 years
- Inflation rate – 1.8%
- Average system losses – 7%
- Reserve margin – 15%
- Displaced natural gas heat rate – 8,000 Btu/kWh
- Solar degradation rate – 0.50%/year
- Solar system year 1 capacity factor – 19%
- Effective Load Carrying Capability (ELCC) – 25%
- Nominal discount rate is used for all Present value calculations.

Sourced Assumptions

1. CT overnight build costs - $910/kW (EIA Table 8.2 "Cost and Performance Characteristics of New Central Station Electricity Generating Technologies")
2. CT construction time – 2 years (EIA Table 8.2 "Cost and Performance Characteristics of New Central Station Electricity Generating Technologies")
3. Natural gas prices – EIA 2013 Annual Energy Outlook, Nominal delivered prices Electrical Power
4. T&D spend – Failure to Act The economic impact of current Investment Trends in Electricity Infrastructure – ASCE (sourced from EEI)
5. Annual retail sales in the United States – EIA retail sales of electricity for all sectors
6. 16 ¢/kWh for non-climate change factors and 1.5 ¢/kWh from carbon at the midpoint of $30/ton all in $2007 from natural gas generation (National Research Council 2010).

Appendix C. VOS Tariff by Incentive Scenario

This table presents the difference between the three levels of VOS tariffs created for this analysis and the LCOE-PV, as calculated in 50 U.S. locations. The methodology for creating the hypothetical VOS tariffs, the incentive scenarios, and the assumptions that went into the calculation of the LCOE-PV for each location are detailed in Chapter 4 of the report. The LCOE calculations were done using NREL's System Advisor Model, version 2014.1.14, using input data for the most populous city of each state across the U.S. The results of the calculation for each location under each scenario are given in the rows of the table below. The names of the locations have been removed; this because it is not the intent of this report to provide analysis regarding the specific costs of, or market for, solar development in any particular location. Instead, the focus of this analysis is on the range of market types that might exist under three hypothetical VOS tariff levels, given current solar costs. The colors in the table indicate which market type results for each case. If the difference between the VOS and the LCOE-PV is well below zero (pink), there is a price-support market, if it is approaching zero (yellow) there is a transitional market, and if it is positive (green) there is a price-competitive market.

LEGEND

Difference between VOS and LCOE of PV < 0
-3 < Difference between VOS and LCOE of PV > 0
Difference between VOS and LCOE of PV > -3

WITHOUT INCENTIVES			30% ITC (no State Incentives)			WITH 30% ITC + State Incentives as of Jan2014		
VOS-LCOE Differential			VOS-LCOE Differential			VOS-LCOE Differential		
Low VOS 4.9 ¢/kWh	Medium VOS 7.5 ¢/kWh	High VOS 11¢/kWh	Low VOS 4.9 ¢/kWh	Medium VOS 7.5 ¢/kWh	High VOS 11¢/kWh	Low VOS 4.9 ¢/kWh	Medium VOS 7.5 ¢/kWh	High VOS 11¢/kWh
-22.19	-19.63	-16.11	-12.55	-9.99	-6.47	-12.55	-9.99	-6.47
-17.83	-15.27	-11.75	-9.70	-7.14	-3.62	-8.35	-5.79	-2.27
-16.30	-13.74	-10.22	-8.76	-6.20	-2.68	-8.15	-5.59	-2.07
-15.80	-13.24	-9.72	-8.40	-5.84	-2.32	-7.96	-5.40	-1.88
-15.71	-13.15	-9.63	-8.35	-5.79	-2.27	-7.42	-4.86	-1.34
-15.42	-12.86	-9.34	-8.16	-5.60	-2.08	-7.36	-4.80	-1.28
-15.38	-12.82	-9.30	-8.15	-5.59	-2.07	-6.97	-4.41	-0.89
-15.12	-12.56	-9.04	-7.96	-5.40	-1.88	-6.89	-4.33	-0.81
-15.10	-12.54	-9.02	-7.95	-5.39	-1.87	-6.83	-4.27	-0.75
-15.10	-12.54	-9.02	-7.94	-5.38	-1.86	-6.82	-4.26	-0.74
-14.83	-12.27	-8.75	-7.77	-5.21	-1.69	-6.79	-4.23	-0.71
-14.51	-11.95	-8.43	-7.57	-5.01	-1.49	-6.79	-4.23	-0.71
-14.48	-11.92	-8.40	-7.55	-4.99	-1.47	-6.76	-4.20	-0.68
-14.38	-11.82	-8.30	-7.49	-4.93	-1.41	-6.68	-4.12	-0.60
-14.38	-11.82	-8.30	-7.48	-4.92	-1.40	-6.64	-4.08	-0.56
-14.32	-11.76	-8.24	-7.45	-4.89	-1.37	-6.57	-4.01	-0.49
-14.32	-11.76	-8.24	-7.44	-4.88	-1.36	-6.32	-3.76	-0.24
-14.28	-11.72	-8.20	-7.42	-4.86	-1.34	-6.22	-3.66	-0.14
-14.18	-11.62	-8.10	-7.36	-4.80	-1.28	-6.03	-3.47	0.05
-14.13	-11.57	-8.05	-7.33	-4.77	-1.25	-6.02	-3.46	0.06
-14.08	-11.52	-8.00	-7.29	-4.73	-1.21	-5.86	-3.30	0.22
-13.98	-11.42	-7.90	-7.24	-4.68	-1.16	-5.65	-3.09	0.43
-13.73	-11.17	-7.65	-7.07	-4.51	-0.99	-5.57	-3.01	0.51
-13.72	-11.16	-7.64	-7.07	-4.51	-0.99	-5.49	-2.93	0.59
-13.68	-11.12	-7.60	-7.04	-4.48	-0.96	-5.31	-2.75	0.77
-13.57	-11.01	-7.49	-6.97	-4.41	-0.89	-5.27	-2.71	0.82
-13.45	-10.89	-7.37	-6.89	-4.33	-0.81	-5.19	-2.63	0.89
-13.43	-10.87	-7.35	-6.87	-4.31	-0.79	-5.03	-2.47	1.05
-13.41	-10.85	-7.33	-6.86	-4.30	-0.78	-4.85	-2.29	1.23
-13.36	-10.80	-7.28	-6.83	-4.27	-0.75	-4.68	-2.12	1.40
-13.30	-10.74	-7.22	-6.81	-4.25	-0.73	-4.67	-2.11	1.41
-13.28	-10.72	-7.20	-6.79	-4.23	-0.71	-4.22	-1.66	1.86
-13.11	-10.55	-7.03	-6.68	-4.12	-0.60	-3.98	-1.42	2.10
-13.06	-10.50	-6.98	-6.64	-4.08	-0.56	-3.92	-1.36	2.16
-13.03	-10.47	-6.95	-6.62	-4.06	-0.54	-3.90	-1.34	2.18
-12.95	-10.39	-6.87	-6.57	-4.01	-0.49	-3.59	-1.03	2.49
-12.84	-10.28	-6.76	-6.50	-3.94	-0.42	-3.42	-0.86	2.66
-12.57	-10.01	-6.49	-6.32	-3.76	-0.24	-3.30	-0.74	2.78
-12.49	-9.93	-6.41	-6.28	-3.72	-0.20	-3.21	-0.65	2.87
-12.39	-9.83	-6.31	-6.22	-3.66	-0.14	-2.84	-0.28	3.24
-12.36	-9.80	-6.28	-6.19	-3.63	-0.11	-1.43	1.13	4.65
-12.12	-9.56	-6.04	-6.06	-3.50	0.02	-1.31	1.25	4.77
-11.85	-9.29	-5.77	-5.86	-3.30	0.22	-1.18	1.38	4.90
-11.84	-9.28	-5.76	-5.86	-3.30	0.22	-1.06	1.50	5.02
-11.38	-8.82	-5.30	-5.57	-3.01	0.51	-0.97	1.59	5.11
-11.28	-8.72	-5.20	-5.50	-2.94	0.58	-0.84	1.72	5.24
-11.27	-8.71	-5.19	-5.48	-2.92	0.60	-0.65	1.91	5.43
-9.92	-7.36	-3.84	-4.61	-2.05	1.47	-0.22	2.34	5.86
-9.76	-7.20	-3.68	-4.51	-1.95	1.57	0.01	2.57	6.09
-9.58	-7.02	-3.50	-4.40	-1.84	1.68	0.91	3.47	6.99

Federal ITC + Hypothetical State ITC of 30%			Federal ITC + Hypothetical State $0.80/W CBI		
VOS-LCOE Differential			VOS-LCOE Differential		
Low VOS 4.9 ¢/kWh	Medium VOS 7.5 ¢/kWh	High VOS 11¢/kWh	Low VOS 4.9 ¢/kWh	Medium VOS 7.5 ¢/kWh	High VOS 11¢/kWh
-5.61	-3.05	0.47	-8.98	-6.42	-2.90
-3.85	-1.29	2.23	-6.86	-4.30	-0.78
-3.32	-0.76	2.76	-6.26	-3.70	-0.18
-3.07	-0.51	3.01	-6.03	-3.47	0.05
-3.04	-0.48	3.04	-5.87	-3.31	0.21
-2.96	-0.40	3.12	-5.76	-3.20	0.32
-2.92	-0.36	3.16	-5.63	-3.07	0.45
-2.81	-0.25	3.27	-5.63	-3.07	0.45
-2.80	-0.24	3.28	-5.62	-3.06	0.46
-2.79	-0.23	3.29	-5.50	-2.94	0.58
-2.69	-0.13	3.39	-5.49	-2.93	0.59
-2.58	-0.02	3.50	-5.30	-2.74	0.78
-2.56	0.00	3.52	-5.29	-2.73	0.79
-2.52	0.04	3.56	-5.28	-2.72	0.80
-2.52	0.04	3.56	-5.26	-2.70	0.82
-2.51	0.05	3.57	-5.24	-2.68	0.84
-2.49	0.07	3.59	-5.20	-2.64	0.88
-2.48	0.08	3.60	-5.10	-2.54	0.98
-2.45	0.11	3.63	-5.05	-2.49	1.03
-2.43	0.13	3.65	-5.04	-2.48	1.04
-2.41	0.15	3.67	-5.04	-2.48	1.04
-2.38	0.18	3.70	-5.02	-2.46	1.06
-2.29	0.27	3.79	-4.85	-2.29	1.23
-2.28	0.28	3.80	-4.84	-2.28	1.24
-2.25	0.31	3.83	-4.73	-2.17	1.35
-2.22	0.34	3.86	-4.70	-2.14	1.38
-2.17	0.39	3.91	-4.70	-2.14	1.38
-2.15	0.41	3.93	-4.68	-2.12	1.40
-2.15	0.41	3.93	-4.67	-2.11	1.41
-2.15	0.41	3.93	-4.65	-2.09	1.43
-2.13	0.43	3.95	-4.59	-2.03	1.49
-2.10	0.46	3.98	-4.57	-2.01	1.51
-2.05	0.51	4.03	-4.52	-1.96	1.56
-2.03	0.53	4.05	-4.50	-1.94	1.58
-2.00	0.56	4.08	-4.48	-1.92	1.60
-1.98	0.58	4.10	-4.40	-1.84	1.68
-1.94	0.62	4.14	-4.35	-1.79	1.73
-1.82	0.74	4.26	-4.27	-1.71	1.81
-1.81	0.75	4.27	-4.18	-1.62	1.90
-1.77	0.79	4.31	-4.17	-1.61	1.91
-1.74	0.82	4.34	-4.13	-1.57	1.95
-1.70	0.86	4.38	-3.94	-1.38	2.14
-1.56	1.00	4.52	-3.92	-1.36	2.16
-1.54	1.02	4.54	-3.88	-1.32	2.20
-1.38	1.18	4.70	-3.67	-1.11	2.41
-1.35	1.21	4.73	-3.56	-1.00	2.52
-1.31	1.25	4.77	-3.49	-0.93	2.59
-0.80	1.76	5.28	-2.86	-0.30	3.22
-0.73	1.83	5.35	-2.68	-0.12	3.40
-0.67	1.89	5.41	-2.66	-0.10	3.42

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Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar

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DISCLAIMER

Executive Summary

Net energy metering (NEM) has helped fuel the adoption of distributed solar across the country. As deployment of solar and other distributed energy resources (DERs) continues to grow, regulators and stakeholders are investigating issues such as how current NEM rate structures reflect the costs and benefits of distributed solar, whether different tariff mechanisms could better align compensation with the value of distributed solar, and how a broader valuation framework could facilitate the maximization of system benefits from DER adoption.

Numerous cost-benefit studies related to NEM have been conducted by a variety of entities, and these studies have often produced widely differing results. This meta-analysis examines a geographically diverse and broad selection of studies from 15 States that explore the costs and benefits of distributed solar. It is not meant to be comprehensive, but rather reviews a representative sample of the most recently published material. The studies represent an evolution of approaches to solar value analysis, and, while the selection captures different approaches and methodologies, every study either identifies or quantifies a defined set of cost-benefit categories related to net metering or distributed solar.

Eighteen categories that could represent positive values (avoided costs) or negative values (incremental costs) are considered in two or more of the studies. Overall, studies tend to converge on at least three value categories: avoided energy generation, avoided generation capacity, and avoided transmission capacity. Common components were more likely to affect the bulk system, have a large net impact, and be readily quantifiable. Less commonality is found across value categories affecting the distribution system, which have incremental impacts and may require more complex approaches to quantification. The set of value categories included, and whether these categories represent costs or benefits, significantly affects the overall results of a given study.

Figure 1. Comparison of value categories across studies

Included	●
Discussed but not monetized/quantified	○
Included/represented in another category	red ●
For NY, included in VDER Phase One	red ○

		Arkansas - Crossborder Energy 2017	Nevada - E3 2016	Louisiana - Acadian Consulting Group 2015	South Carolina - E3 2015	Mississippi - Synapse 2014	Vermont - VT Public Service Dept 2014	Washington DC - Synapse 2017	Georgia - Southern Company 2017	Hawaii - Clean Power Research 2015	Maine - Clean Power Research 2015	Oregon - Clean Power Research 2015	Minnesota - Clean Power Research 2014	Utah - Clean Power Research 2014	New York - BCA Framework 2016 + VDER Phase One	California - LNBA Framework 2016	Total
Utility System Impacts																	
G	Avoided Energy Generation	●	●	●	●	●	●	●	○	○	●	○	○	●	red ○	○	15
	Avoided Generation Capacity	●	●	●	●	●	●	●	○	○	●	○	○	●	red ○	○	15
	Avoided Environmental Compliance	●	●			red ●	●	●	red ○		red ●	○		●		red ○	10
	Fuel Hedging	●			●	●		●		○	●	○	red ●	●			9
	Market Price Response	●					●	●		○	●				○		6
	Ancillary Services		●		●	○		○	○	○					○	○	8
T	Avoided Transmission Capacity	●	●	●	●	●	●	●	○	○	●	○	○	●	red ○	○	15
	Avoided Line Losses	●	●		●	●	red ●	●	○			○		red ●	red ○	○	11
D	Avoided Distribution Capacity	●	●	red ●	red ●	red ●	●	●		○	○	○	○	red ●	red ○	○	14
	Avoided Resiliency & Reliability	○				○		○							○	○	5
	Distribution O&M			●					○						○	○	4
	Distribution Voltage and Power Quality									○	○	○	○		○	○	6
C	Integration Costs	●	●	●	●	○		●	○	○	●	○	○		○	○	13
	Lost Utility Revenues	●	●	●	●	●	●								○		7
	Program and Administrative Costs		●	●	●	●	●	○							○		7
Societal Impacts																	
S	Avoided Cost of Carbon	●					●	●		○	●		○		red ○	○	8
	Other Avoided Environmental Costs	●	●			○		○		○	●		○		○	○	9
	Local Economic Benefit	●				○		○									3

Values that are numerically quantified are represented in the chart with a solid dot. Values that are discussed, but not quantified, are represented in the chart with an open dot. Some studies combined more than one value into a broader category and, where possible, these rolled-up values are noted with a solid red dot. For a more detailed discussion of this chart, see the section “Comparison of Value Categories.”

Other important differences led studies to arrive at diverse conclusions. Some differences are caused by variables that are geographically and situationally dependent, while other differences are driven by the input assumptions used to estimate their value. Studies use a range of assumptions for factors that influence results, such as marginal unit displacement, solar penetration, integration costs, externalities, and discount rates. Furthermore, the stakeholder perspective—whether costs and benefits are examined from the view of customers, the utility, the grid, or society at large—is a key influencer of the methodology employed by the studies and their resulting direction and outcomes.

Overall observations from this analysis show, not surprisingly, that a major challenge in studying and developing an approach to NEM, the value of solar, and DER valuation is that some value components are relatively easy to quantify, while others are more difficult to represent by a single metric or measure. This meta-analysis highlights the different value categories, approaches, and assumptions used in NEM cost-benefit analysis, value of solar studies, and DER valuation frameworks, emphasizing commonalities and differences between them, and how they are evolving over time.

CONTENTS

Definitions of Key Terms

Some key terms used throughout this report are defined below.

Behind-the-meter: A generating unit, multiple generating units, or other resource(s) at a single location (regardless of ownership), of any nameplate size, on the customer's side of the retail meter that serve all or part of the customer's retail load with electric energy. All electrical equipment from, and including, the generation set-up to the metering point is considered to be "behind-the-meter."[1]

Distributed energy resource (DER): A DER is a resource sited close to customers that can provide all or some of their immediate electricity and power needs, and also can be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and located close to the load. Examples of different types of DER include solar photovoltaic, wind, combined heat and power, energy storage, demand response, electric vehicles, microgrids, and energy efficiency.[2]

Distributed solar: Small-scale photovoltaic facilities installed behind-the-meter, typically at residential or commercial sites.

Interconnection cost: The one-time cost (for hardware, labor, etc.) of connecting a distributed photovoltaic system or other DER installation to the local distribution grid, usually to allow the installation's owner to sell any excess electricity production to the local utility. This cost is usually paid by the installation owner, and should be distinguished from the cost of "interconnection studies," which the utility also may require the owner to fund. Such studies may be required, for example, to ensure that connecting the additional distributed photovoltaic system on a given distribution feeder will not affect local voltage stability or otherwise disrupt service to other customers on that feeder.

Net energy metering [or net metering] (NEM): Congress defined "net [energy] metering service" as "service to an electric consumer under which electric energy generated by that consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period."[3]

Value of solar (VOS): Value of solar is an alternative to NEM. The VOS method calculates each of the benefits and costs that distributed solar provides to, or imposes on, the electric system to arrive at a single VOS rate, typically expressed in cents per kilowatt-hour. This is the rate at which customers are

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[1] North American Electric Reliability Corporation (NERC). February 2017. *Distributed Energy Resources: Connection Modeling and Reliability Considerations*. Available at http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf.

[2] National Association of Regulatory Utility Commissioners (NARUC). 2016. *Distributed Energy Resources Rate Design and Compensation Manual*. Available at https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0.

[3] Energy Policy Act of 2005, Sec. 1251, Net Metering and Additional Standards, (a)(11). For additional information, see *Reference Manual and Procedures for Implementation of the "PURPA Standards" in the Energy Policy Act of 2005*, Kenneth Rose and Karl Meusen, March 22, 2006, p. 10.

compensated for electricity generated by their grid-connected distributed photovoltaic systems. Unlike NEM, the VOS tariff dissociates the customer payments for electricity consumed from the compensation they receive for solar electricity generated. Under a VOS tariff, the utility purchases some (i.e., the net excess) or all of the generation from a solar installation at a rate that is independent of retail electricity rates.[4]

[4] National Renewable Energy Laboratory (NREL), U.S. DOE. 2015. *Value of Solar: Program Design and Implementation Considerations*. Available at https://www.nrel.gov/docs/fy15osti/62361.pdf.

Introduction

Net energy metering (NEM) is a method that adapts traditional monthly metering and billing practices to compensate owners of distributed generation facilities for electricity exported to the grid. The customer can offset the electricity they draw from the grid throughout the billing cycle. The net energy consumed from the utility grid over the billing period becomes the basis for the customer's bill for that period. The level of compensation varies by State, depending on the policies in place. In some States, utilities compensate NEM customers for excess generation at the full retail rate, while other States specify something other than the retail rate.[5]

NEM is credited with being one of the main policy drivers behind the widespread and rapidly increasing adoption of distributed solar photovoltaic (PV) across the United States. According to the U.S. Energy Information Administration (EIA), residential small-scale solar PV capacity has increased significantly in recent years, reaching 7.4 gigawatts (GW) in 2016, a 43 percent increase from 2015. Small-scale PV capacity (systems less than 1 megawatt [MW]) in the commercial and industrial sectors has also grown, with combined capacity in those two sectors increasing 26 percent in 2016, reaching nearly 5.8 GW. This growth is projected to continue, with EIA forecasts reaching 13.7 GW in the residential sector and 8.2 GW in the commercial and industrial sectors in 2018.[6]

NEM has traditionally been used as a mechanism for compensating PV customers, typically residential and commercial customers with behind-the-meter solar, for electricity they produce onsite. However, opportunities and challenges associated with the increasing penetration of solar and other distributed energy resources (DERs) are causing utilities and policymakers to examine methods to address the full range of costs and benefits associated with these behind-the-meter resources.

New economic conditions that arise with the introduction of distributed solar in a utility service territory can affect utilities and ratepayers, and are some of the main challenges leading to investigations of NEM. Concerns related to the ability of the utility to recover its fixed costs for operating the grid have led to questions about how NEM affects cost recovery. Similarly, the impact that net-metered PV may have on non-solar customers has initiated analyses of how NEM and other solar pricing models may affect retail electricity prices. Nevertheless, NEM has been introduced as an effective mechanism to compensate customers with onsite PV generation and has successfully enabled increased deployment of distributed solar PV.

Stakeholders across the country are debating the future of NEM, and many States are undertaking policy actions to amend NEM laws and rules or to study the value of solar (VOS) through cost-benefit analysis.[7] In addition, some States are engaged in legislative, regulatory, and rate design discussions related to NEM successor tariffs, including States with currently low penetrations of distributed PV. As the

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[5] For additional information on net metering, see National Renewable Energy Laboratory (NREL), U.S. DOE. State, Local, & Tribal Governments, Net Metering. Available at https://www.nrel.gov/technical-assistance/basics-net-metering.html.

[6] U.S. Energy Information Administration (EIA). July 11, 2017. "EIA adds small-scale solar photovoltaic forecasts to its monthly Short-Term Energy Outlook." Available at https://www.eia.gov/todayinenergy/detail.php?id=31992.

[7] North Carolina Clean Energy Technology Center. 2017. *The 50 States of Solar: Q4 2016 Quarterly Report & Annual Review, Executive Summary.* Available at https://nccleantech.ncsu.edu/wp-content/uploads/Q42016_ExecSummary_v.3.pdf.

deployment of other distributed resources, such as storage, energy efficiency measures, demand response, and electric vehicles, is expected to grow, some regulators and utilities are working on broader valuation methodologies to provide a foundation for understanding the comprehensive benefits and costs associated with increased DER deployment on the grid. This understanding can then be used to inform pricing, program, and procurement strategies that serve multiple objectives, including maximizing benefits for all customers.

These policy and regulatory trends have spurred a significant amount of analysis by States, utilities, and other stakeholders to examine the costs and benefits of net metering and the value of DERs more broadly. In this report, ICF reviews a selection of 15 studies to identify broad themes and highlight emerging issues that influence how stakeholders are studying the impacts of net metering and distributed solar.

The studies that are the focus of this meta-analysis have different objectives, ask different questions, and arrive at different results. In summary, the review demonstrates a historic lack of consensus around a preferred methodology for valuing the costs and benefits of distributed solar, and emphasizes how choices about input assumptions and the perspective from which value is assessed is a strong influencer of study results. The meta-analysis also demonstrates a shift toward more comprehensive and defined approaches to valuing distributed solar and DERs more broadly.

Approach

This report is a meta-analysis of 15 studies related to the costs and benefits of NEM and distributed solar. The selection was made by collecting a broad list of more than 40 relevant studies, and narrowing it based on a set of criteria to ensure that the sample reviewed represents a balanced cross section of the most recently available material from a variety of stakeholder groups and prepared by various research firms. The following criteria guided study selection:

- The study identifies a set of value categories that can be applied to distributed PV.
- The study was released in 2014, or later, and was not included in earlier meta-analyses.
- The selection includes studies from different regions of the country.
- The selection includes studies from jurisdictions with different amounts of PV adoption.
- The selection includes studies prepared by different research firms or utilities.
- The selection includes studies that were sponsored or commissioned by different organizations (e.g., State utility commissions, utility companies, consumer advocates, environmental groups).

Each study was carefully reviewed and categorized using a matrix to allow for comparison and to uncover trends.

This report begins with a summary of key observations. Next, it describes how the studies were selected and groups them into three types: NEM cost-benefit analyses, VOS/NEM successor studies, and broader DER value frameworks. Then, it identifies and defines the value categories included and notes factors that influence how values are quantified. After that, the report provides a more detailed comparison of the value categories and discusses some of the methodological elements and input assumptions that can cause findings to vary. The last section provides brief summaries of each of the studies reviewed.

Key Observations

Studies represent an evolution of approaches to solar value analysis.
States, through their regulated utilities, have historically relied on NEM as a mechanism for compensating distributed solar; however, the increasing penetration of solar and associated technologies is causing utilities and policymakers to examine how NEM addresses the full range of costs and benefits of distributed solar. As distributed solar penetration continues to rise, some regulators and utilities have started developing broader valuation methodologies and frameworks that can be applied to distributed solar, as well as other distributed resources, in a technology-neutral way. These valuation frameworks can then be used to inform how these resources might be compensated for the services they provide through appropriate pricing, programs, and procurement strategies for PV and other DERs. The studies in this review represent an evolution of approaches and include studies that analyze NEM, studies on VOS, and documents that establish broader DER value frameworks. These frameworks are currently in development and, in many ways, are a work in progress.

Overall value depends substantially on which costs and benefits are included and monetized in a study.
ICF's review identified 18 value categories considered in two or more of the studies. Three value categories, all on the wholesale power system, are included in all studies: avoided energy generation, avoided generation capacity, and avoided transmission capacity. Ten or more of the studies included value categories related to avoided environmental compliance costs, avoided line losses (including transmission and distribution), avoided distribution capacity, and integration costs (a negative value). Less common value categories tended to be those that are more challenging to quantify. The set of value categories included, and whether these categories represent costs or benefits, have a significant impact on the overall results of a given study.

Evolution of Value to the Distribution System

Assessing the value of DERs requires analysis of broader impacts on the wholesale system and locational net benefits on the distribution system. Bulk system value categories, such as avoided energy generation, avoided generation capacity, and avoided transmission capacity, are relatively common and generally simple to quantify.

Similarly, incorporating distribution system value components in a staged order, starting with values that are the largest and most readily quantifiable, is a practical approach to capturing near-term value. For example, distribution capacity deferral represents a value component with long-term and substantial value that may be a good first step, and several States, including New York and California, have quantified it. As a second step, States may look toward the additional value of increasingly complex components such as reliability, resilience, and voltage management.

The main takeaway is that the quantification of locational value beyond avoided or delayed investment in capital costs is an ongoing process that continues to evolve. For more information on the evolutionary pathway of distribution system value components, see *Missing Links in the Evolving Distribution Markets* (De Martini, et al., 2016).

Approaches to defining the value categories and methods for quantifying them vary across studies and affect the results.
Common terms and definitions of those terms are not uniformly applied across the studies to refer to the value categories, and the categories are not always defined to include the same elements.

Furthermore, not all studies include a quantitative value; some only discuss how a value could be calculated. Still, there is some degree of alignment across many, but not all, of the categories, which makes it potentially possible to establish common definitions and identify similar or otherwise nuanced approaches to quantifying values for categories across the studies. This review identifies examples of how studies differ in their definitions of categories and quantification approaches to demonstrate how these decisions can affect the findings.

The perspective from which value is assessed affects which value categories are included and how they are quantified.
Cost and benefit considerations change depending on the perspective from which the value is being assessed. Depending on the perspective taken—a utility's business perspective, the ratepayer's consumer perspective, or the grid operator's technical perspective—particular value categories may be more or less relevant. Furthermore, an analysis focused only on utility and ratepayer values will produce different results from an analysis that considers broader policy goals affecting society at large. The perspective also influences whether some categories are included as costs or as benefits. Many of the studies consider multiple perspectives by applying a range of cost-effectiveness tests typically used by utilities to assess the costs and benefits of energy efficiency programs for different stakeholder groups.[8] In analyzing the results or findings from the selection of studies, it is important to consider to whom the benefits and costs accrue and how that perspective affects outcomes.

Studies use a range of input assumptions for factors that influence results, such as marginal unit displacement, solar penetration, integration costs, externalities, and discount rates.
A range of input assumptions are used in quantifying values for the cost-benefit categories. This review identifies several assumptions used in the studies for important factors such as marginal unit displacement, solar PV penetration, integration costs, externalities and societal values, and discount rates associated with the analysis. Just as values are sensitive to differences in which value categories are included, how they are quantified, and where the value accrues, they are also influenced by choices in input assumptions. Each of these factors are discussed in the section "Input Assumptions."

Selection of Studies Analyzed

ICF conducted a literature search to determine relevant studies from across the country to include in this meta-analysis. After identifying more than 40 relevant studies prepared over the past decade, the list was narrowed to a selection of 15.[9] The goal was not to analyze an exhaustive list, but to review a sample that represents a balanced cross section of the most recently available analyses sponsored by organizations with different perspectives and prepared by various research firms. Table 1 lists the selection of studies reviewed.[10] Appendix A provides a citation and brief summary of each study

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[8] The traditional cost-effectiveness tests—the Participant Cost Test (PCT), Utility Cost Test (UCT), Rate Impact Measure (RIM), Total Resource Cost (TRC) Test, and Societal Cost Test (SCT)—and the perspectives addressed by each test are discussed further in the section "Stakeholder Perspective."

[9] The full list of studies considered for inclusion is included as Appendix C.

[10] We use the term "studies" to refer to the documents reviewed in the meta-analysis for simplicity; however, some may be more accurately described as reports or other materials. For some States, we relied on utility commission orders, staff reports, working group recommendations, or other documentation of the costs and benefits currently being considered by regulators. For other States, we relied on documents that provide only a

analyzed. Note that more than one document was reviewed in New York and California as a reflection of ongoing regulatory activities.

Table 1. Selection of studies analyzed

State	Year	Study Sponsor	Prepared by
Arkansas	2017	Sierra Club	Crossborder Energy
District of Columbia	2017	Office of the People's Counsel	Synapse Energy Economics
Georgia	2017	Southern Company	Southern Company
California	2016	California Public Utility Commission (CPUC)	CPUC/Energy and Environmental Economics (E3)
Nevada	2016	State of Nevada Public Utilities Commission	E3
New York	2016	New York Public Service Commission (PSC)	NY Department of Public Service (DPS) Staff
Hawaii	2015	Interstate Renewable Energy Council	Clean Power Research
Louisiana	2015	Louisiana Public Service Commission	Acadian Consulting Group
Maine	2015	Maine Public Utility Commission	Clean Power Research
Oregon	2015	Portland General Electric	Clean Power Research
South Carolina	2015	South Carolina Office of Regulatory Staff	E3
Minnesota	2014	Minnesota Department of Commerce	Clean Power Research
Mississippi	2014	Public Service Commission of Mississippi	Synapse Energy Economics
Utah	2014	Utah Clean Energy	Clean Power Research
Vermont	2014	Public Service Department (PSD) Staff	VT PSD

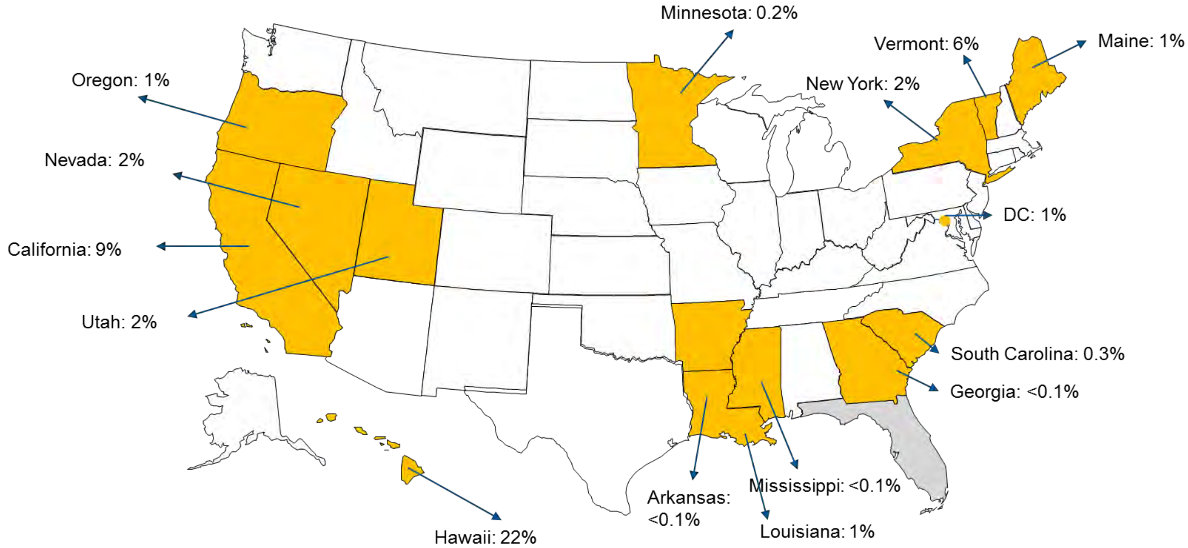
All of the studies reviewed are from 2014 or later. Half were commissioned by State utility commissions and the remaining studies were commissioned by utility companies, consumer advocates, environmental groups, research organizations, or other State agencies. A handful of firms specialize in preparing cost-benefit studies, and this report includes a sample prepared by different firms. However, some firms prepared more than one study of the 15 studies reviewed here; Synapse Energy Economics prepared two studies, Energy and Environmental Economics (E3) was involved in three of the studies, and Clean Power Research prepared five studies.

The selection reflects geographic diversity and includes States with different amounts of distributed PV adoption and growth. Five studies are specific to a single utility service territory, with the remaining studies focused on a single State or the service territories of multiple utilities in the same State. Figure 2 indicates States where the studies came from and the estimated penetration of NEM PV nameplate capacity as a percentage of peak load in those States in 2016.[11]

methodology for assessing costs and benefits in a certain jurisdiction, rather than verifying whether benefits outweigh the costs or vice versa.

[11] We estimate PV penetration by dividing NEM PV capacity (MW) by peak load (MW). For NEM PV capacity, data by State was obtained from EIA at https://www.eia.gov/electricity/data/eia861. For peak load, we map States by the National Energy Modeling System (NEMS) region and use *Annual Energy Outlook* (AEO) 2016 sales data (MWh), adjusted for transmissions losses, to calculate net energy needed to meet load in the State. Net energy is divided by the load factor for the NEMS region to derive peak load. Transmission losses and load factor are obtained from

Figure 2. Geographic diversity of studies and estimated PV penetration, 2016



While the selection captures different approaches and valuation methodologies, every study either identifies or quantifies a defined set of cost-benefit categories related to net metering or distributed solar. In general, cost of service studies are not considered because they are fundamentally different from cost-benefit analyses.[12] Cost of service studies are used to estimate and allocate the embedded and operating costs across groups of customers, and are more geared toward cost allocation and rate design than distributed solar and DER valuation.[13]

As part of a broader literature review, ICF reviewed existing meta-analyses of solar studies, checked the individual studies included for relevance, and avoided replicating evaluation of studies that had been previously reviewed, where possible.[14] For more information on solar PV cost-benefit studies prepared

U.S. Energy Information Administration (EIA). 2016. *Annual Energy Outlook*. Available at https://www.eia.gov/outlooks/aeo/pdf/0383(2016).pdf.

[12] The studies from Louisiana and South Carolina include sections on cost of service; however, our review did not address these components. In addition, New York ordered utilities to calculate utility marginal cost of service (MCOS) to determine distribution value components in their Value of DER Phase One tariff.

[13] Barbose, Galen; John Miller; Ben Sigrin; Emerson Reiter; Karlynn Cory; Joyce McLaren; Joachim Seel; Andrew Mills; Naïm Darghouth; and Andrew Satchwell. 2016. *On the Path to SunShot: Utility Regulatory and Business Model Reforms for Addressing the Financial Impacts of Distributed Solar on Utilities.* Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-65670. Available at http://www.nrel.gov/docs/fy16osti/65670.pdf.

[14] Existing meta-analyses of solar studies include Weissman, Gideon, and Bret Fanshaw. 2016. *Shining Rewards: The Value of Rooftop Solar Power for Consumers and Society.* Available at https://environmentamerica.org/sites/environment/files/reports/AME%20ShiningRewards%20Rpt%20Oct16%201.1.pdf; Institute for Energy Innovation. 2017. *Solar Energy in Michigan: The Economic Impact of Distributed Generation on Non-Solar Customers.* Available at https://www.instituteforenergyinnovation.org/impact-of-dg-on-nonsolar-ratepayers; and Rocky Mountain Institute (RMI). 2013. *A Review of Solar PV Benefit & Cost Studies.* Available at https://rmi.org/wp-content/uploads/2017/05/RMI_Document_Repository_Public-Reprts_eLab-DER-Benefit-Cost-Deck_2nd_Edition131015.pdf.

prior to 2014, see the Rocky Mountain Institute's meta-analysis, *A Review of Solar PV Benefit & Cost Studies*.[15]

Types of Studies

The studies in this review represent an evolution of approaches to solar value analysis and can be broadly grouped into three types: NEM cost-benefit analysis, VOS/NEM successor studies, and broader DER value frameworks. In general, these groupings reflect differences in policy context as many States have considered changes to NEM policies in recent years. Table 2 identifies how the studies were grouped and the following discussion summarizes the three types.

Table 2. Grouping of study types

Type of Study	Number Reviewed	Description of Study Type	States/Prepared by
NEM Cost-Benefit Analysis	6	Evaluate costs and benefits of a NEM program; study whether NEM is creating a cost-shift to non-participating ratepayers.	▪ Arkansas (Crossborder) ▪ Louisiana (Acadian) ▪ Mississippi (Synapse) ▪ Nevada (E3) ▪ South Carolina (E3) ▪ Vermont (VT PSD)
VOS/NEM Successor	7	Discuss the impacts of NEM and consider options for reforming or realigning rates with the net impacts of distributed solar in ways that go beyond net metering.	▪ District of Columbia (Synapse) ▪ Georgia (Southern Company) ▪ Hawaii (CPR) ▪ Maine (CPR) ▪ Minnesota (CPR) ▪ Oregon (CPR) ▪ Utah (CPR)
DER Value Frameworks	2	Reflect the elements of regulatory activities that look at VOS as part of a more precise approach within a framework that can be applied to other DERs.	▪ California LNBA (CPUC) ▪ New York BCA (Department of Public Service Staff)

Six of the studies can be considered NEM cost-benefit analyses. These tend to evaluate the impact of extending an existing or launching a new NEM program, or study whether an existing NEM program is creating an unfair cost-shift to non-participating ratepayers. This issue, sometimes called cross-subsidization, refers to a potential shift in costs away from solar PV customers, who might avoid paying for some fixed grid costs, toward non-PV customers, who make up the difference of these grid costs in their rates.[16,17] For example, the study from Vermont included an analysis of "the existence and magnitude of any cross subsidy created by the current net metering program."

[15] Rocky Mountain Institute (RMI), 2013.
[16] For more information on the cost recovery and cost-shift issues associated with DER in rate making, see NARUC, 2016, *Distributed Energy Resources Rate Design and Compensation Manual*.
[17] A 2017 report from the Lawrence Berkeley National Laboratory (LBNL) explored the potential rate impacts of distributed solar and concluded that the effects are small compared to other issues, such as the impact of energy efficiency and natural gas prices on retail electricity prices. However, the study found that for States and utilities

Seven of the studies can be considered VOS/NEM successor studies. These analyses tend to discuss the impacts of NEM and consider options for reforming or realigning rates to account for the net impacts of distributed solar in ways that may go beyond NEM. For example, Minnesota passed legislation in 2013 requiring the development of a methodology to calculate a VOS tariff as an alternative to NEM. The Minnesota study included in this review documents the methodology approved by the Minnesota Public Utilities Commission, which would be used by utilities to calculate the rate at which electricity generated by PV customers is compensated.[18]

The New York and California studies can be considered broader DER value frameworks, which look at VOS within a methodological framework that can be applied to other, customer-sited technologies in addition to solar. In New York, the Department of Public Service (DPS) staff developed a benefit-cost analysis framework, known as the "BCA Framework," for utilities to evaluate DER alternatives as substitutes for traditional investments. More recently, DPS established the Phase One Value of DER (VDER) methodology, which transitions away from traditional NEM and provides the basis for a "Value Stack" tariff, under which compensation is calculated using five of the most readily quantifiable DER values. Efforts are currently underway in Phase Two of VDER to develop a Value Stack tariff for smaller residential rooftop solar and other DER technologies. Similarly, in California, the California Public Utilities Commission (CPUC) set up the Locational Net Benefit Analysis (LNBA) Working Group to develop a methodology for the three investor-owned utilities to use to value DER by location. CPUC approved the LNBA for use by utilities in demonstration projects and the framework continues to be refined.

Instead of a single valuation methodology for distributed solar, these frameworks are evolving to account for the temporal and locational value associated with DER projects at specific locations and with specific generation profiles and characteristics, and are being used to inform the next approach to compensating DER in these States. In the DPS report from New York that was reviewed for this meta-analysis, the authors describe NEM as an important and easy-to-understand compensation mechanism that effectively fostered solar PV in the State, but say that NEM provides an "imprecise and incomplete signal of the full value and costs of DERs."[19] The ongoing proceedings are aimed at developing pricing for DERs that better reflect the actual values they create.

While all of the studies provide a methodology for considering the costs and benefits of distributed PV, the three types of studies have different objectives, ask different questions, and arrive at different results. The NEM studies tend to apply the value categories (which are discussed in detail in the next section) to investigate the fairness of a compensation structure. The VOS studies use the value categories to administratively determine a compensation rate that is more precise than the NEM approach. The Value of DER frameworks apply the value categories in a way that aligns compensation

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with exceptionally high distributed solar penetration levels, the effects could begin to approach the same scale as other important drivers. See Barbose, Galen. 2017. *Putting the Potential Rate Impacts of Distributed Solar into Context*. p. 31. Available at https://emp.lbl.gov/sites/default/files/lbnl-1007060.pdf. Note: LBNL's study is not included in this meta-analysis because it does not attempt to provide a cost-benefit analysis of distributed solar, support an approach to defining a value of solar, or provide a valuation framework for other DERs.

[18] Minnesota Public Utilities Commission (MN PUC). 2014. Order Approving Distributed Solar Value Methodology. Docket No. E-999/M-14-65. April 1, 2014. Available at https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7bFC0357B5-FBE2-4E99-9E3B-5CCFCF48F822%7d&documentTitle=20144-97879-01.

[19] New York Department of Public Service (NY DPS), 2016(b), p. 4.

with system value and grid services provided, while also providing a method for integrating the value of DERs into utility system planning processes. Several studies derive an actual VOS, while others present an approach to quantification, but do not derive specific values to populate those categories.

These fundamental differences in scope and objective make it difficult to directly compare outcomes because studies do not always have a common goal or seek to investigate the same issue(s). Grouping the studies into three types based on objective (NEM, VOS, or DER Value Frameworks) helps to compare studies that are similar to each other; however, not all studies fit squarely into one of the three types. For example, the study from the District of Columbia is classified as VOS, but it also includes a NEM cost-shift analysis. The study from Georgia is classified as VOS, but it is intended to be a broad framework that is also applicable to utility-scale solar. Summaries of each study are provided in Appendix A and clearly indicate the analytical goal or objective of a study and the related outcomes.

In addition to different objectives driving varied outcomes, the perspective from which value is assessed influences which value categories are included and is likely to produce different results. Further still, regional factors, including regulatory structures, weather conditions, and wholesale and distribution grid characteristics, can drive differences and, in some cases, the application of the same analytic method in different areas can produce dissimilar results. The goal of the study, the perspective from which costs and benefits are evaluated, and relevant regional factors are not always explicitly stated in a study, further complicating direct comparison.

With these issues in mind, the selection of studies result in a range of findings related to the costs and benefits of NEM and distributed solar. Of the six NEM studies, two demonstrate that total benefits exceed total costs, two conclude that costs exceed overall benefits, and two found that NEM-related cost-shifting was either *de minimus* or "close to zero." Of the seven VOS studies, three quantify a State-specific VOS, while four provide a methodology but do not produce a specific estimate. Lastly, the two Value of DER frameworks provide a methodology for assessing costs and benefits, but do not produce a specific estimate. Table 3 summarizes the principal findings of the studies reviewed.

Table 3. Summary of principal findings

State	Year	Prepared by	Principal Findings
NEM Cost-Benefit Analysis			
Arkansas	2017	Crossborder	Benefits of residential distributed generation (DG) exceed the costs; do not impose a burden on other ratepayers.
Nevada	2016	E3	Cost-shift amounts to a levelized cost of $0.08/kWh for existing installations.
Louisiana	2015	Acadian	Costs associated with solar NEM installations outweigh their benefits.
South Carolina	2015	E3	NEM-related cost-shifting was *de minimus* due to the low number of participants.
Mississippi	2014	Synapse	NEM provides net benefits under almost all of the scenarios and sensitivities analyzed.
Vermont	2014	PSD	NEM results in "close to zero" costs to non-participating ratepayers, and may be a net benefit.
VOS/NEM Successor			
District of Columbia	2017	Synapse	Utility system VOS is $132.66/MWh (2015$); cost-shifting remains relatively modest.
Georgia	2017	Southern Company	Provides a methodology for assessing costs and benefits; no specific estimate is produced.
Hawaii	2015	CPR	Provides a methodology for assessing costs and benefits. Preliminary results suggest a net benefit.
Maine	2015	CPR	Value of distributed PV is $0.337/kWh (levelized).
Oregon	2015	CPR	Provides a methodology for assessing costs and benefits; no specific estimate is produced.
Minnesota	2014	CPR	Provides a methodology for assessing VOS; no specific estimate is produced.
Utah	2014	CPR	VOS is $0.116/kWh levelized.
DER Value Frameworks			
California	2016	CPUC	Provides a methodology for assessing costs and benefits; no specific estimate is produced.
New York	2016	NY DPS	Provides a methodology for assessing costs and benefits; no specific estimate is produced.

Value Category Definitions

ICF's review identified 18 value categories that were considered in two or more of the studies.[20] Studies differed greatly in the selection of categories, approaches to quantification, and the selection of assumptions. This section presents a set of common definitions to define and refer to categories, and discusses important characteristics about each category, such as which assumptions matter to its resulting value. Table 4 lists the value categories and identifies the parts of the system that reflect these

[20] An assortment of miscellaneous categories were not assessed in more than one study. Some provide a slightly different take on one of the more common categories described later in this section. Examples include an "SREC SIPE" category used in the District of Columbia study to address the potential Supply Induced Price Effect associated with solar renewable energy certificates; a "generation remix" category used in the framework from Georgia to represent the impact that a large penetration of renewable resources could have on system commitment, dispatch, and future generation build-out; and a net non-energy benefits category used in the BCA in New York, which relates to avoided utility or grid operations (e.g., avoided service terminations, avoided uncollectible bills, avoided noise and odor impacts), or incurred costs (e.g., indoor emissions, noise disturbance).

values, including the value to the generation system (G), the transmission system (T), the distribution system (D), the cost categories (C), and the external value to society (S).[21] The table also shows whether the category represents a cost or a benefit, and the frequency with which each value category is addressed in the studies.

Table 4. Summary of value categories used in studies

	Value Category	Benefit (+) or Cost (-)	Number of Studies Addressing this Category
Utility System Impacts			
G	Avoided Energy Generation	+	15
	Avoided Generation Capacity	+	15
	Avoided Environmental Compliance	+	10
	Fuel Hedging	+	9
	Market Price Response	+	6
	Ancillary Services	+/-	8
T	Avoided Transmission Capacity	+	15
	Avoided Line Losses	+	11
D	Avoided Distribution Capacity	+	14
	Avoided Resiliency & Reliability	+	5
	Distribution O&M	+/-	4
	Distribution Voltage and Power Quality	+/-	6
C	Integration Costs	-	13
	Lost Utility Revenues	-	7
	Program and Administrative Costs	-	7
Societal Impacts			
S	Avoided Cost of Carbon	+	8
	Other Avoided Environmental Costs	+	9
	Local Economic Benefit	+	3

The number of studies addressing a value category is the sum of the studies that quantify an actual value (including a zero value) or provide an approach to quantifying the value within a methodology. Two studies provided “placeholders” for certain categories and these are considered “addressed” and included in the sum, where applicable. Categories that were not addressed are those that are entirely absent or explicitly not intended for inclusion in valuation. For a more detailed look at which studies addressed a particular value category, see Figure 3 in a following section, “Comparison of Value Categories.”

[21] Most studies did not indicate a system level for cost categories, so we do not assign one.

Utility System Impacts

Generation

Avoided Energy Generation

This value category reflects the avoided cost of generating energy from system resources due to the output of distributed solar PV or other DERs. The cost of operating the displaced marginal generating resource is the primary driver of determining the value, and this value is sensitive to several assumptions about what that marginal unit is and therefore what comprises the cost of that avoided generation. The price of fuel for the generation resource displaced on the margin is a dominant factor in the value. Studies from regions with Independent System Operators (ISOs) tend to calculate avoided energy generation based on wholesale market prices. In non-ISO regions, natural gas is typically assumed to fuel the marginal unit, and most studies rely on natural gas price forecasts and standard assumptions for heat rates, depending on whether the marginal unit is assumed to be combined cycle or a combustion turbine.

Avoided energy also can address additional factors, including assumptions about variable costs for the displaced marginal unit, such as variable operations and maintenance costs, which are generally low.[22] Depending on the study, the avoided cost of energy also can include avoided environmental compliance costs and other factors that are part of the wholesale price. For example, in California, utilities can use locational marginal prices to determine avoided energy costs, and the avoided cost of carbon allowances from its cap and trade program are embedded in the wholesale energy value.[23] In contrast, the study from Nevada uses the hourly marginal wholesale value of energy, excluding the regulatory price of carbon dioxide emissions.[24] All of the studies evaluated include the avoided wholesale energy category, but with different assumptions. Studies that use locational marginal prices are also implicitly accounting for transmission congestion on the system to supply wholesale power to that node or aggregation of nodes.

Avoided Generation Capacity

This value category reflects the amount of central generation capacity that can be deferred or avoided due to the installation of distributed PV or other DERs. Key drivers include the effective capacity of a DER (i.e., coincidence with system peak) and system capacity needs.[25] The value is calculated based on the avoided cost of the marginal capacity resource and the effective capacity of the distributed resource. Similar to avoided energy generation, some studies assume natural gas combustion turbines

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[22] Rocky Mountain Institute (RMI), 2013, p. 25.
[23] California Public Utilities Commission (CPUC). 2016(a). *Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B.* Rulemaking 14-08-013. Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769. pp. 23, 27. Available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M161/K474/161474143.PDF.
[24] Price, S.; Z. Ming; A. Ong; and S. Grant. 2016. *Nevada Net Energy Metering Impacts Evaluation 2016 Update*. San Francisco, CA: Energy and Environmental Economics, Inc. p. 32. Available at http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2016-8/14264.pdf.
[25] Rocky Mountain Institute (RMI), 2013.

and sometimes combined cycle units for the plant being deferred, while others use estimates from capacity markets if they exist in the region.

Several studies apply an Effective Load Carrying Capacity (ELCC) method to measure the amount of additional load that can be met by the distributed resource. For solar PV, the ELCC can be significant because PV generation may be reliably available at peak times and can effectively increase the grid's generating capacity.[26] On the other hand, in places where solar generation is more variable or not coincident with the peak, and in places with increasing solar penetration, solar may not provide capacity at times when it is needed. Assumptions about future load growth, future solar growth, and their impact on the shape and timing of the system peak also affect the ability of variable distributed resources to avoid or defer system capacity needs. All studies include this category.

Avoided Environmental Compliance

This value category reflects the avoided cost of complying with Federal, regional, State, and local environmental regulations. This could include the compliance costs of either existing or anticipated carbon emissions standards or standards related to other criteria pollutants. Several studies include avoided environmental compliance within the avoided energy generation value category, which eliminates the need for this separate value category. Some studies may address the avoided cost of purchasing renewable energy to comply with State renewable portfolio standard (RPS) requirements; this meta-analysis includes those avoided costs here. The value depends on State-specific targets and the current generation mix. This value does not include any avoided societal costs, which includes the social cost of carbon, and is addressed separately and discussed in the Societal Benefits section below. Ten out of the 15 studies include avoided environmental compliance. Three specifically address avoided RPS costs and only the study from the District of Columbia quantifies it.[27]

Fuel Price Hedging

This value category reflects the avoided costs to the utility based on reduced risk and exposure to the volatile fuel prices of conventional generation resources. Because renewable generation has no fuel costs, the cost of solar generation is not subject to fluctuations in fuel price. The forecasted price of fuel for the displaced marginal resource is the primary driver of this component. This value can be assessed as a benefit to the utility or a broader benefit to society. From the utility perspective, the value reflects their reduced risk in fuel price volatility. From the societal perspective, it can reflect the benefit that all customers may experience from reduced utility rate fluctuations. Nine studies include the fuel hedging category.

Market Price Response

This value category reflects a change in wholesale energy or capacity market prices due to increased penetration of renewable generation. As PV penetration increases, the demand for conventional

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[26] The ELCC of a power generator represents its ability to effectively increase the generating capacity available to a utility or a regional power grid without increasing the utility's loss of load risk. See Perez, R.; R. Margolis; M. Kmiecik; M. Schwab; and M. Perez. 2006. *Update: Effective Load-Carrying Capability of Photovoltaics in the United States.* Conference Paper. Golden, CO: National Renewable Energy Laboratory. NREL/CP-620-40068. Available at https://www.nrel.gov/docs/fy06osti/40068.pdf.

[27] This category does not apply in all States. For the District of Columbia, there is a solar carve-out within their RPS, which sets a specific target for solar PV generation from grid-connected systems and significantly affects the value.

generation and capacity resources may be reduced, which could have the effect of lowering energy prices. Six studies include market price response. Most studies approximate the market price suppression effect using analysis based on the 2013 Avoided Energy Supply Cost (AESC) study.[28]

Ancillary Services
This value category reflects any increase or decrease in costs associated with the need for generation reserves to provide grid support services such as reactive supply, voltage control, frequency regulation, spinning reserve, energy imbalance, and scheduling. The ability to monitor and control distributed PV and other DERs is an important factor that affects the ability of these variable resources to provide ancillary services at the time of need.

Regions of the country with established markets for ancillary services may find it easier to include and quantify this category. Some of the frameworks reviewed gave an approach to quantifying avoided ancillary services. For example, E3 uses 1 percent of avoided energy in the South Carolina study.[29] In New York, the BCA uses a 2-year average of ancillary service costs, but recognizes that a case-by-case approach would be more accurate.[30] Eight studies include this value category. Some studies may assume an increase in ancillary services as a component of integration costs, discussed below.

Transmission

Avoided Transmission Capacity
This category reflects the avoided costs of transmission constraints from the addition of distributed PV or other DERs, which may or may not defer planned transmission infrastructure upgrades or replacements. The characteristics of the bulk system and DER penetration levels may influence this component. All studies include this value category, although several combine it with avoided distribution capacity and apply a single value for avoided transmission and distribution capacity.[31] The studies took various approaches to calculate the avoided cost of transmission capacity as a result of the installation of NEM eligible solar PV systems. Most commonly, the benefits were calculated by assessing the utility's marginal cost of load-related transmission capacity, as opposed to any specific line cost analysis. Inputs to the calculation include historical transmission capacity expenditures, which can be

[28] The 2013 AESC study was prepared by Synapse and was sponsored by a group representing the major electric and gas utilities in New England, as well as efficiency program administrators, energy offices, regulators, and advocates. Synapse conducted prior AESC studies in 2007, 2009, and 2011, and is currently conducting a 2018 study (http://www.synapse-energy.com/project/avoided-energy-supply-costs-new-england).
[29] Patel, K.; Z. Ming; D. Allen; K. Chawla; and L. Lavin. 2015. *South Carolina Act 236: Cost Shift and Cost of Service Analysis*. San Francisco, CA: Energy and Economics, Inc. p. 11. Available at http://www.regulatorystaff.sc.gov/electric/industryinfo/Documents/Act%20236%20Cost%20Shifting%20Report.pdf.
[30] New York Department of Public Service (NY DPS), 2016(a), Appendix C, p. 7.
[31] Stanton, E.; J. Daniel; T. Vitolo; P. Knight; D. White; and G. Keith. 2014. *Net Metering in Mississippi: Costs, Benefits, and Policy Considerations*. Cambridge, MA: Synapse Energy Economics, Inc. Available at https://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf; Dismukes, D. 2015. *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers.* Baton Rouge, LA: Acadian Consulting. Available at http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=f2b9ba59-eaca-4d6f-ac0b-a22b4b0600d5; Norris, B. 2014. *Value of Solar in Utah*. Clean Power Research. Available at https://pscdocs.utah.gov/electric/13docs/13035184/255147ExAWrightTest5-22-2014.pdf; and Patel, et al., 2015.

based on publicly available Federal Energy Regulatory Commission (FERC) Form 1 data or data provided by the utility, and the load-carrying contribution made by solar PV.

Avoided Line Losses

This category reflects the value of energy that would otherwise be lost due to inefficiencies in transmitting and distributing energy over long distances from the central station to the point of consumption. EIA estimates that electricity transmission and distribution losses average about 5 percent of the electricity that is transmitted and distributed annually in the United States.[32] Losses are generally calculated by developing an average loss factor, and they vary based on time of day and the characteristics of the utility system. Avoided line losses also may be reflected in other value categories. For example, several of the studies prepared by Clean Power Research employ a loss savings factor approach instead of using a separate value category to address line losses.[33] Studies may include both energy-related and capacity-related losses. Eleven studies include this value category.

Distribution

Avoided Distribution Capacity

This category reflects the avoided costs due to the DER's ability to reduce load and defer or avoid planned distribution infrastructure upgrades or replacements to the distribution system. The value is sensitive to load growth rate at the distribution feeder or substation level, locational load shape characteristics, and penetration of DERs and their coincidence with load on that feeder or substation. All studies except one include this value category. Some studies combine it with avoided transmission capacity and apply a single value for avoided transmission and distribution capacity.

Avoided Reliability and Resiliency Costs

This category reflects avoided costs to the distribution system from the reduction in the frequency and duration of utility grid outages and the provision of back-up services, which reduce the impacts on customers. Five studies include this category; however, it is challenging to quantify, and no study in this review calculates a specific value.[34] The study from Mississippi includes a discussion of the value categories that it did not monetize and describes how avoided outage costs could be represented in cost-benefit analyses using a value of lost load estimation, or the amount that customers would be willing to pay to avoid interruption of their electric service. However, the study indicates that there is not "sufficient evidence to estimate the extent to which solar NEM would improve reliability" at this time.[35] The study from the District of Columbia discusses reliability in terms of outage frequency, duration, and breadth in its treatment of societal benefits, but indicates that it is difficult to "credibly forecast" when smart inverters will be deployed, how they will be used in reducing outages for

[32] U.S. Energy Information Administration (EIA). Frequently Asked Questions, How much electricity is lost in transmission and distribution in the United States? Available at https://www.eia.gov/tools/faqs/faq.php?id=105&t=3.

[33] For a detailed description of the loss savings factor approach, see Norris, 2015(a), p. 17.

[34] The terms "resilience" and "reliability" are sometimes used interchangeably and are not clearly defined or distinguished in the studies.

[35] Stanton, et al., 2014, p. 35.

distributed solar customers, and how these deployments may result in lower expenditures for the utility.[36]

Distribution Operations and Maintenance (O&M)
This category can be assessed as either a cost or a benefit. It generally reflects any increase or decrease in O&M costs associated with utility investments in distribution assets and infrastructure services as a result of deploying distributed solar on the distribution system. Four studies include distribution O&M as either a cost or a benefit. In some studies, the negative value could be assumed to be included in the integration cost category, discussed later in this section.

Distribution Voltage and Power Quality
This category can be assessed as either a cost or a benefit. It generally reflects any increase or decrease in the costs of maintaining voltage and frequency on the distribution system within acceptable ranges during electric service delivery, and to potentially improve power quality. Six studies include the value of distribution voltage and/or power quality costs, but none of the studies quantify it. Some studies may address this value within ancillary services or integration costs, discussed in the next section.

Costs

Integration Costs
This category reflects costs incurred by the utility to integrate and manage distributed solar and other DERs on the utility grid. For example, investments may be required to support voltage regulation, upgrade transformers, increase available fault duty, and provide anti-islanding protection.[37] Integration costs may include scheduling, forecasting, and controlling DERs, as well as procurement of additional ancillary services such as reserves, regulation, and fast-ramping resources.[38] Most studies do not specify what specific investments are assumed to be included in integration costs or whether integration costs are assumed to apply at the distribution or transmission level. However, the studies from the District of Columbia, Louisiana, and South Carolina include interconnection costs, which is typically a distribution system-level consideration. Thirteen studies include this category.[39]

Lost Utility Revenues
This category reflects the loss of revenues to the utility due to reduced retail customer loads associated with customer-sited DERs. Lost revenues are the result of NEM participants paying smaller electric bills and are equivalent to customer bill savings. The value represents a potential cost-shift, and is applied when determining whether utility rates for all customers will increase, which some studies evaluated

[36] Whited, M.; A. Horowitz; T. Vitolo; W. Ong; and T. Woolf. 2017. *Distributed Solar in the District of Columbia: Policy Options, Potential, Value of Solar, and Cost-Shifting*. Cambridge, MA: Synapse Energy Economics. p. 49. Available at http://www.synapse-energy.com/sites/default/files/Distributed-Solar-in-DC-16-041.pdf.
[37] Bird, L.; M. Milligan; and D. Lew. 2013. *Integrating Variable Renewable Energy: Challenges and Solutions.* Available at https://www.nrel.gov/docs/fy13osti/60451.pdf.
[38] National Efficiency Screening Project (NESP). 2017. *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources.* Available at https://nationalefficiencyscreening.org/wp-content/uploads/2017/05/NSPM_May-2017_final.pdf.
[39] The framework developed in Georgia does not specifically reference "integration costs" but it includes costs associated with support capacity, which we consider costs associated with integration. Similarly, the study from Louisiana does not specifically reference integration costs, but it does include interconnection costs and we consider that value as a cost associated with integration.

using the Rate Impact Measure (RIM) test.[40] Seven studies include this value category, while others argue that lost revenues are not a new cost created by net-metered systems.[41]

Program and Administrative Costs
This category reflects the costs incurred by the utility to administer various DER incentive programs. It can include both the cost of State incentive payments and the cost of administering them, compliance and reporting activities, personnel, billing costs, and other administrative costs to implement and maintain a formal program. Seven studies include this value category.

Societal Impacts

Benefits

Avoided Cost of Carbon
This category reflects avoided costs to society from reduced carbon emissions. It does not include avoided costs to the utility related to carbon emissions otherwise included in avoided energy costs or avoided environmental compliance value categories. This category is meant to capture additional avoided costs that accrue to broader society from mitigating climate change. Eight studies include this value category and three quantify it based on the Social Cost of Carbon developed by the U.S. Environmental Protection Agency. Studies may use a netting out process, such as the one described in the study from Maine, to ensure that this value category only reflects the net social costs of carbon and does not double-count avoided utility costs associated with carbon emissions that are embedded in energy prices.[42]

Other Avoided Environmental Costs
This category reflects the societal value of reduced environmental impacts related to public health improvements from reduced criteria air pollutants (SO_2, NOx, etc.), methane leakage, and impacts on land and water. Avoided criteria pollutants are addressed in nine of studies as a separate category from the impact of emissions prices on allowance markets that may be included in the avoided generation cost category. Four studies discuss avoided impacts on land and water. Two studies discuss avoided methane leakage.

Economic Development
This category reflects economic growth benefits such as jobs in the solar industry, local tax revenues, or other indirect benefits to local communities resulting from increased distributed solar deployment. Local economic benefit is challenging to quantify and is heavily influenced by assumptions. Three studies

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[40] The purpose of the RIM test is to indicate whether a resource will increase or decrease electricity or gas rates. When regulators take steps to allow utilities to recover lost revenues through rate cases, revenue decoupling, or other means, then the recovery of these lost revenues will create upward pressure on rates. If this upward pressure on rates exceeds the downward pressure from reduced utility system costs, then rates will increase, and vice versa (NESP, 2017).
[41] Stanton, et al., 2014, p. 33.
[42] Norris, B.; P. Gruenhagen; R. Grace; P. Yuen; R. Perez; and K. Rabago. 2015. *Maine Distributed Solar Valuation Study*. Prepared for Maine Public Utilities Commission by Clean Power Research, Sustainable Energy Advantage, LLC, and Pace Law School Energy and Climate Center. p. 35. Available at http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-FullRevisedReport_4_15_15.pdf.

discuss this value category; only the study from Arkansas quantifies a value and includes it in its assessment of societal costs.[43]

Comparison of Value Categories

Included	●
Included/represented in another category	●
Discussed but not monetized/quantified	○
For NY, included in VDER Phase One	○

The following section provides a more detailed comparison of how the categories are treated across the studies. Figure 3 identifies which studies include each category. Values that are numerically quantified in the study are represented on the chart with a solid dot. Values that are discussed, but not quantified, are represented on the chart with an open dot. Some studies combined more than one value into a broader category and, where possible, these rolled-up values are noted with a solid red dot. For New York, the BCA includes a broader set of value categories than the Value of DER (VDER) Phase One Tariff. An open red dot indicates that the value category is also included in VDER Phase One.[44]

[43] Beach, R. Thomas, and Patrick G. McGuire. 2017. *The Benefits and Costs of Net Metering Solar Distributed Generation on the System of Entergy Arkansas, Inc*. Crossborder Energy. p. 28. Available at https://drive.google.com/file/d/0BzTHARzy2TINbHViTmRsM2VCQUU/view.

[44] For Phase One of VDER, five categories make up the Value Stack: energy, capacity, environmental, demand reduction value, and locational system relief value. Because VDER uses locational marginal prices (LMPs), we assume that the common value categories associated with "avoided transmission capacity" and "avoided line losses" are included, because transmission congestion and losses are implicitly embedded in the LMP. However, the LMP does not factor in avoided costs from deferring transmission upgrades nor apply a specific line loss percentage. For the two distribution system values—demand reduction and locational system relief—we use the common value category associated with "avoided distribution capacity" as a rough substitute, but VDER values are more specifically aimed at measuring peak load reduction in higher value areas.

Figure 3. Comparison of value categories across studies

		Arkansas - Crossborder Energy 2017	Nevada - E3 2016	Louisiana - Acadian Consulting Group 2015	South Carolina - E3 2015	Mississippi - Synapse 2014	Vermont - VT Public Service Dept 2014	Washington DC - Synapse 2017	Georgia - Southern Company 2017	Hawaii - Clean Power Research 2015	Maine - Clean Power Research 2015	Oregon - Clean Power Research 2015	Minnesota - Clean Power Research 2014	Utah - Clean Power Research 2014	New York - BCA Framework 2016 + VDER Phase One	California - LNBA Framework 2016	**Total**
Utility System Impacts																	
G	Avoided Energy Generation	●	●	●	●	●	●	●	○	○	●	○	○	●	○	○	**15**
	Avoided Generation Capacity	●	●	●	●	●	●	●	○	○	●	○	○	●	○	○	**15**
	Avoided Environmental Compliance	●	●			●	●	●	○		●	○		●		○	**10**
	Fuel Hedging	●			●	●		●		○	●	○	●	●			**9**
	Market Price Response	●					●	●		○	●				○		**6**
	Ancillary Services		●		●	○		○	○	○					○	○	**8**
T	Avoided Transmission Capacity	●	●	●	●	●	●	●	○	○	●	○	○	●	○	○	**15**
	Avoided Line Losses	●	●		●	●	●	●	○			○		●	○	○	**11**
D	Avoided Distribution Capacity	●	●	●	●	●	●	●		○	○	○	○	●	○	○	**14**
	Avoided Resiliency & Reliability	○				○		○							○	○	**5**
	Distribution O&M			●					○						○	○	**4**
	Distribution Voltage and Power Quality									○	○	○	○		○	○	**6**
C	Integration Costs	●	●	●	●	○		●	○	○	●	○	○		○	○	**13**
	Lost Utility Revenues	●	●	●	●	●	●								○		**7**
	Program and Administrative Costs		●	●	●	●	●	○							○		**7**
Societal Impacts																	
S	Avoided Cost of Carbon	●					●	●		○	●		○		○	○	**8**
	Other Avoided Environmental Costs	●	●			○		○		○	●		○		○	○	**9**
	Local Economic Benefit	●				○		○									**3**

Included	●
Included/represented in another category	●
Discussed but not monetized/quantified	○
For NY, included in VDER Phase One	○

The most common categories were impacts on the bulk power system: avoided energy generation, avoided generation capacity, and avoided transmission capacity (all the studies include them). The second most common categories, included in 10 or more studies, were avoided environmental compliance, avoided line losses (including transmission and distribution), avoided distribution capacity, and integration costs.

The least common cost-benefit categories, included in five or fewer studies, were distribution O&M, avoided resiliency and reliability, and economic development. Avoided resiliency and reliability, as well as economic development benefits, have proven to be somewhat challenging to calculate, which may explain why a number of studies did not include them. Studies that emphasize locational value, such as New York and California, may consider the resilience, reliability, and other benefits at the distribution level more effectively than studies taking statewide or system-level approaches.

Studies that do include these values describe their approaches to calculating it. The California LNBA measures system reliability/resilience by monitoring System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Momentary Average Interruption Frequency Index (MAIFI) results.[45, 46] Similarly, the New York BCA Framework includes reliability/resilience values in terms of net avoided restoration costs and net avoided outages. Net avoided restoration costs are calculated by comparing the number of outages and the speed and costs of restoration before and after a project is implemented to find the difference. Avoided outage costs are similarly calculated by determining how a project affects the number and length of an outage and multiplying by the estimated costs of an outage. The estimated cost is determined by customer class and geographic region. For both avoided restoration costs and avoided outages, some portion of this value is already factored in the transmission and distribution (T&D) infrastructure costs, and this category represents the net avoided cost.[47]

Figure 4 shows the range of magnitude of value categories as a percentage of net impact. Figure 5 shows value stacks from five studies that clearly document values.[48] Avoided energy tended to provide the largest share of benefits out of all the categories. Avoided generation capacity and fuel hedging also tended to make up significant portions of the value stack. For studies that include societal benefits such as the avoided cost of carbon and other avoided environmental costs, these components can make up significant portions of the value stack, such as in the Arkansas and Maine studies, or they may have more modest values, such as in the District of Columbia and Utah studies. The size of avoided carbon

[45] California Public Utilities Commission (CPUC), 2016(a), p. 29.

[46] The LNBA currently includes the value of increased reliability from DERs where DERs can defer or avoid an otherwise necessary investment to bring reliability up to an acceptable level; however, consensus has not been reached on whether the non-capacity benefits of increased reliability associated with the frequency, duration, or magnitude of customer outages should be factored in. See California Public Utilities Commission (CPUC). 2017. *Locational Net Benefit Analysis Working Group Final Report.* Rulemaking 14-08-013. Order Instituting Rulemaking Regarding Policies and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code 769, and Related Matters. March 8. p. 36. Available at http://drpwg.org/wp-content/uploads/2016/07/R1408013-et-al-SCE-LNBA-Working-Group-Final-Report.pdf.

[47] New York Department of Public Service (NY DPS, 2016(a), Appendix C, pp. 2, 14.

[48] Four studies presented quantified values that we were not able to draw upon, either because they would have required visual assumptions or were otherwise incomparable.

and other environmental values depends on a number of factors, such as the generation mix being displaced by distributed PV in the region and the approach used to calculate the social cost of carbon.

Figure 4. Range of magnitude of value categories as a percentage of net impact

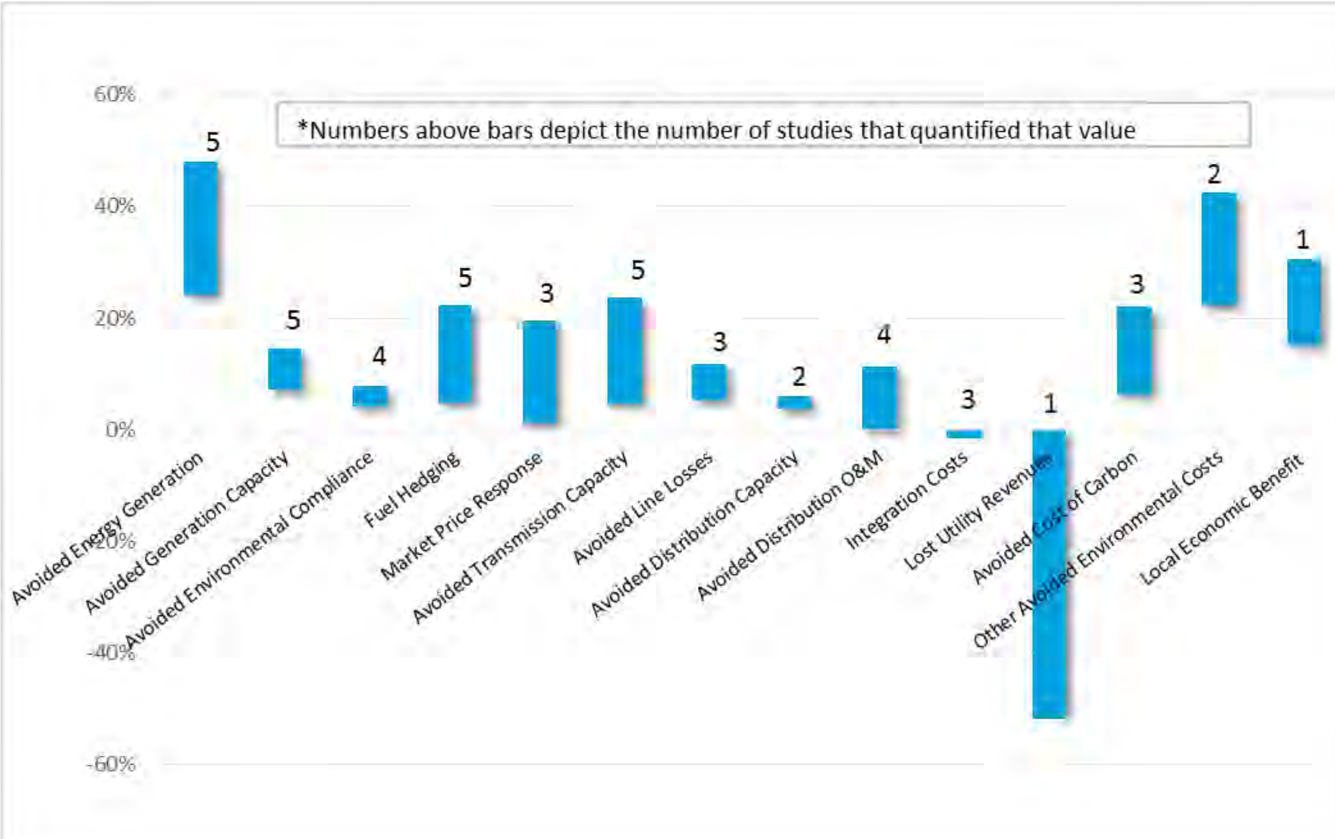
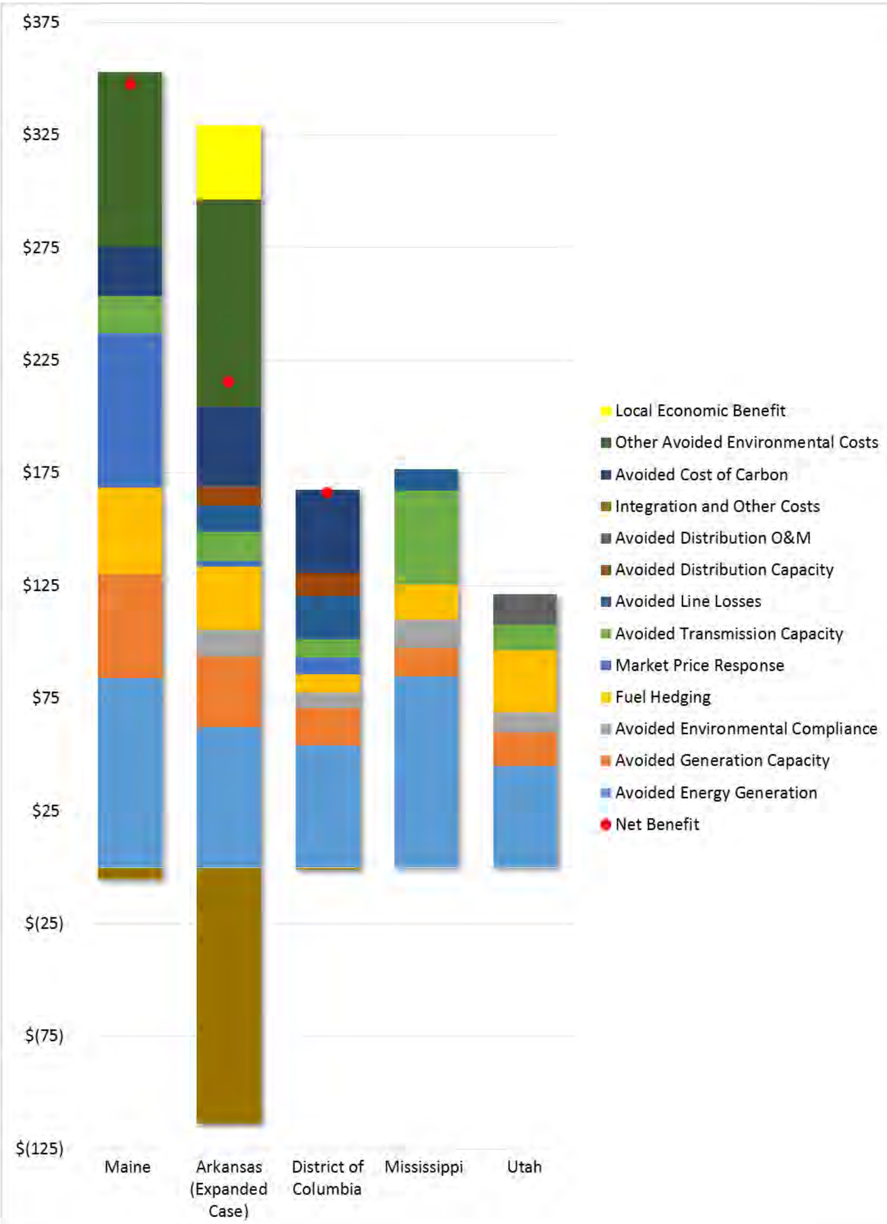


Figure 5. Comparison of value stacks (for studies that documented values)



* Values expressed in 2017 dollars per MWh, levelized over 25 years (except for the District of Columbia, which used 24 years). Studies that expressed values in varying dollar years and in dollars per KWh were converted. The Arkansas study looked at two sets of avoided costs, including an "expanded case," which includes a broader set of categories and is shown here. The District of Columbia's cost categories are included, but are not visible because the value is small. The Mississippi study considered two cost categories (reduced revenue and administrative costs) but neither value is shown because the detailed data were not found in the study. Utah did not include separate cost categories. Louisiana is not represented in the figure because costs and benefits are presented in net present value terms and do not lend themselves to comparison.

Stakeholder Perspective

In addition to the differences in value categories described above, there are differences in the perspectives of the studies that can affect the value categories included. For example, when assessing the value of NEM, distributed solar, and other DERs, it is important to recognize where the benefits or costs accrue. Costs and benefits can accrue at least to three different stakeholder groups—ratepayers, the utility, and the grid—with most studies evaluating multiple stakeholder perspectives. Some of the differences among these perspectives are discussed in this section.

From the ratepayer perspective, a customer with a PV system can experience a certain set of costs and benefits. Benefits can include a reduction in utility bills as a result of self-generation and financial incentives from the utility in the form of NEM. Costs include the capital investment in the PV system and costs associated with ongoing maintenance of the system. However, customers without PV systems also may be affected and may experience costs and benefits as a result of the systems installed by others. For example, if the utility's cost for implementing NEM exceeds the estimated benefit, the utility could increase rates for all customers to make up for the shortfall, and customers without PV would pay more as a result of the NEM program. At least five of the studies explore concerns about potential "cross subsidization" between those customers installing rooftop solar and those who do not.

From the utility's perspective, its business can experience both benefits and costs due to NEM and distributed solar. Some values that constitute a benefit for the ratepayer can present themselves as a cost to the utility. For example, the benefit of bill savings to the customer is the same as lost revenue to the utility. If and how that lost revenue is captured though different rate designs can affect both participating (i.e., with PV systems) and non-participating (i.e., without PV systems) customers.

From a grid perspective, NEM and distributed PV and other DERs can provide benefits and incur costs to the electric grid as a function of the resource's location and operational characteristics. The benefits and costs of a particular resource reflect distribution system factors such as load relief, reliability, power quality, voltage regulation, and resilience. In addition, the net benefits of these resources can reflect issues on the bulk system, such as resource adequacy and system flexibility, as well as societal benefits related to emission reductions, health impacts, and environmental justice.

Nine studies also consider a fourth perspective—the perspective of a broader society—which can result in variations in the costs and benefits assessed. For example, the value category associated with the cost of carbon can be assessed for its utility system value and its societal value. From the utility perspective, the cost of carbon reflects an emissions allowance price, either in an observed market or one used by the utility for planning purposes. The value component takes on a different, and potentially more substantial, value when it is assessed from the societal perspective, where it reflects the benefit that all society may experience from lower carbon emissions. This concept is further discussed in a later section, "Societal Values."

Many of the studies in this meta-analysis accounted for multiple perspectives in their assessments. The inclusion or omission of a given perspective is sometimes determined by the jurisdiction in which the study is being performed, either legislatively or in regulatory dockets. The following excerpt from the South Carolina study provides an example:

> "While advocates of renewable energy point to numerous environmental and societal benefits that could be included in an analysis of the Value of DER, the directive of Act 236 was to develop a methodology that would 'ensure that the electrical utility recovers its cost of providing electrical service to customer-generators and customers who are not customer-generators.' Therefore, the Methodology is limited to the quantifiable benefits and costs currently

> experienced by the Utility. Likewise, the analysis performed for this report focuses on the quantifiable benefits and costs to the Utility with recognition that those benefits and costs experienced by the Utility are ultimately passed on to its ratepayers."[49]

One approach, taken by seven of the studies, to assess various stakeholder perspectives is to apply one or more of the set of cost-effectiveness tests that are typically applied to energy efficiency programs. These include the Total Resource Cost (TRC) test, Utility Cost Test (UCT), Participant Cost Test (PCT), Societal Cost Test (SCT), and Rate Impact Measure (RIM) Test. Figure 6 provides an overview of the tests. For more information on these cost tests, see the National Efficiency Screening Project's 2017 *National Standard Practice Manual*.[50]

Figure 6. Overview of cost-effectiveness tests (adapted from the National Efficiency Screening Project)

Test	Perspective	Key Question Answered	Summary Approach
Utility cost	The utility system	Will utility system costs be reduced?	Includes the costs and benefits experienced by the utility system
Total Resource Cost	The utility system plus participating customers	Will utility system costs plus program participants' costs be reduced?	Includes the costs and benefits experienced by the utility system, plus costs and benefits to program participants
Societal Cost	Society as a whole	Will total costs to society be reduced?	Includes the costs and benefits experienced by society as a whole
Participant Cost	Customers who participate in an efficiency program	Will program participants' costs be reduced?	Includes the costs and benefits experienced by the customers who participate in the program
Rate Impact Measure	Impact on rates paid by all customers	Will utility rates be reduced?	Includes the costs and benefits that will affect utility rates, including utility system costs and benefits plus lost revenues

[49] Patel, et al., 2015 p. 7.
[50] NESP, 2017.

Figure 7 notes which of the five traditional cost-effectiveness tests were used by the studies in this meta-analysis as an indicator of the perspectives considered. For studies that did not apply cost-effectiveness tests, either cost-effectiveness was not assessed or other analytical methods were used such as the Cost of Service or Revenue Requirements approaches. When evaluating the results of the studies, the perspective of which stakeholders' lens or lenses were applied should be noted.

Figure 7. Summary of cost-effectiveness test used in studies

			Cost-Effectiveness Test				
State	**Year**	**Prepared by**	**PCT**	**UCT**	**RIM**	**TRC**	**SCT**
Arkansas	2017	Crossborder	√	√	√	√	√
District of Columbia	2017	Synapse		√			√
Georgia	2017	Southern Company					
California	2016	CPUC	√		√		
Nevada	2016	E3	√	√	√	√	√
New York	2016	NY DPS		√	√		√
Hawaii	2015	CPR					
Louisiana	2015	Acadian					
Maine	2015	CPR					
Oregon	2015	CPR					
South Carolina	2015	E3			√		
Minnesota	2014	CPR					
Mississippi	2014	Synapse	√			√	
Utah	2014	CPR					
Vermont	2014	PSD					

Input Assumptions

This section includes a discussion of input assumptions that can cause studies to arrive at different outcomes, including assumptions about the displaced marginal unit, PV penetration levels, treatment of integration costs, inclusion of externalities, and choices about discount rates.

Displaced Marginal Unit

Generation from distributed solar is assumed to displace the marginal generation unit, resulting in avoided energy costs. Generators are generally dispatched in merit or lowest cost order to meet load, and the resource displaced on the margin is the next highest cost generator that can reduce its output in response to solar output. More than one method is used in the studies to estimate which plants are on the margin. Some studies use a typical generator, such as a combined-cycle gas turbine, or a blended mix of generators, as a simple proxy for the avoided generator. Most studies use wholesale market prices based on historical locational marginal prices. A third approach is to use a dispatch model or some other form of production simulation run to estimate what resource is on the margin when distributed solar is expected to displace generation.

Assumptions about the efficiency of the marginal unit (heat rates) and the price of fuel for the marginal unit are dominant factors in avoided energy input costs. In most cases, natural gas was assumed to be the marginal fuel. Most studies estimate future natural gas prices using EIA's *Annual Energy Outlook* or some other source, such as New York Mercantile Exchange (NYMEX) gas futures. In Hawaii, oil-fired generation is predominant and the study recommends using futures for oil instead of natural gas, and transportation to the island would have to be factored in. The study from Maine also acknowledged that fuel oil may occasionally be the marginal fuel and, in such cases, natural gas displacement was used as a simplifying assumption.[51] In New York, Locational Based Marginal Pricing (LBMP) is used, which represents the cost of the marginal generator plus congestion pricing.[52] The Georgia study uses an hourly approach to estimate the cost of avoided energy, and does not assume a single fuel or technology.[53] For a more detailed look at assumptions from the individual studies on displaced marginal units, see Appendix C.

Solar Penetration

A 2012 report from the Lawrence Berkeley National Laboratory (LBNL) examined changes in the economic VOS PV at relatively high penetration levels and identified a decrease in value components as penetration increases.[54] For penetrations of 0 percent to 10 percent, LBNL found that the primary driver was a decrease in capacity value because additional PV is less effective at avoiding new non-renewable generation capacity at high penetration than at low penetration. For penetrations of 10 percent and higher, the primary driver was a decrease in energy value because additional PV starts to displace generation with lower variable costs at higher penetration levels. In California, a glut of solar generation in the middle of the day from both the central station and distributed solar has contributed to a situation where solar generation is exported to surrounding States during high solar/low load periods.

ICF reviewed the studies for considerations related to PV penetration and to identify what ranges of PV penetration levels were considered. Penetration level is expressed in terms of total distributed solar nameplate capacity as a percentage of total peak capacity. The 15 studies generally considered current or near-term penetration levels with estimates ranging from 0.2 percent to 6 percent, as shown in Table 5. The table also indicates estimated penetration of NEM PV capacity as a percentage of peak load in 2016 for the States where the studies came from.[55]

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[51] Norris, B. 2015(b). *Valuation of Solar + Storage in Hawaii: Methodology*. Prepared for the Interstate Renewable Energy Council (IREC) by Clean Power Research. p. 11. Available at http://www.irecusa.org/wp-content/uploads/2015/06/IREC-Valuation-of-Solar-Storage-in-HI_Methodology_2015.pdf; Norris, et al., 2015, p. 19.
[52] New York Department of Public Service (NY DPS), 2016(a), Appendix C, p. 5.
[53] Southern Company. 2017. *A Framework for Determining the Costs and Benefits of Renewable Resources in Georgia.* Revised May 12, 2017. p. 9. Available at http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=167588.
[54] Mills, Andrew, and Ryan Wiser. 2012. *Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California.* Berkeley, CA: Lawrence Berkeley National Laboratory. p. 7. Available at https://emp.lbl.gov/sites/all/files/lbnl-5445e.pdf. Table ES.1 shows decomposition of the marginal economic value of PV in 2030, with increasing penetration from 0 percent to 30 percent.
[55] We estimate PV penetration by dividing NEM PV nameplate capacity (MW) by peak load (MW). For NEM PV capacity, data by State was obtained from EIA at https://www.eia.gov/electricity/data/eia861. For peak load, we map States by NEMS region and use AEO 2016 sales data (MWh), adjusted for transmissions losses, to calculate net energy needed to meet load in the State. Net energy is divided by the load factor for the NEMS region to derive peak load. Transmission losses and load factor are obtained from AEO 2016.

Table 5. PV penetration assumed in studies reviewed

State	Year	Prepared by	PV Penetration Specified in Study	Estimated PV Penetration (2016)
Arkansas	2017	Crossborder	Below 5%	0.1%
District of Columbia	2017	Synapse	Current levels	1%
Georgia	2017	Southern Company	Unspecified	<0.1%
California	2016	CPUC	Unspecified	9%
Nevada	2016	E3	Approx. 3%	2%
New York	2016	NY DPS	Unspecified	2%
Hawaii	2015	CPR	Unspecified	22%
Louisiana	2015	Acadian	0.5%	1%
Maine	2015	CPR	Approx. 0.2%	1%
Oregon	2015	CPR	Unspecified	1%
South Carolina	2015	E3	2% in 2021	0.3%
Minnesota	2014	CPR	Near-term level	0.2%
Mississippi	2014	Synapse	0.5%	<0.1%
Utah	2014	CPR	Unspecified	2%
Vermont	2014	PSD	Approx. 6%	6%

Studies that only present methodologies or valuation frameworks tended not to specify assumptions about penetration levels, but some discuss the need to reflect penetration increases. For example, in Minnesota, the change in PV penetration level is accounted for in an annual adjustment to account for the impact of higher solar penetration on hourly utility load profiles and Effective Load Carrying Capacity (ELCC) and Peak Load Reduction (PLR) calculations.[56] ELCC and PLR are used in some studies in calculations of avoided generation capacity and avoided transmission and distribution capacity.

Some studies also may consider higher penetration rates in considerations related to integration costs. For example, the studies from Arkansas and Oregon reference a 2014 report by the Pacific Northwest National Laboratory (PNNL) for Duke Energy that indicated a trend of increasing PV integration costs at successively higher PV levels in the utility's service territory.[57] While solar generation for the nation is likely to remain below 3 percent over the next 5 years, some States are expected to reach much higher levels.[58] Nevada, California, Hawaii, and Vermont are all projected to have more than 20 percent of their generation from solar by 2021, which could affect value categories.[59]

Integration Costs

The majority of studies include costs incurred by the utility to integrate distributed solar; however, very few specify which costs they are referring to or differentiate between costs on the bulk power system or

[56] Norris, B.; M. Putnam: and T. Hoff. 2014. *Minnesota Value of Solar: Methodology.* Prepared for the Minnesota Department of Commerce, Division of Energy Resources by Clean Power Research. pp. 5–6, p. 17. Available at https://www.cleanpower.com/wp-content/uploads/MN-VOS-Methodology-2014-01-30-FINAL.pdf.
[57] Beach and McGuire, 2017, p. 34; Norris, 2015(a), p. 25; and Pacific Northwest National Laboratory (PNNL). n.d. *Duke Energy Photovoltaic Integration Study: Carolinas Service Areas.* Available at http://www.pnucc.org/sites/default/files/Duke%20Energy%20PV%20Integration%20Study%20201404.pdf.
[58] Feldman, D.; D. Boff; and R. Margolis. 2016. *Q3/Q4 2016 Solar Industry Update*. Available at https://www.nrel.gov/docs/fy17osti/67639.pdf.
[59] Ibid., p. 9.

the distribution system. A 2015 National Renewable Energy Laboratory (NREL) report defines integration costs as the change in production costs associated with a system's ability to accommodate the variability and uncertainty of the net load.[60] That report investigated four components of production costs: cycling costs, non-cycling variable operations and maintenance costs (VO&M), fuel costs, and reserves provisioning costs. It did not include capital and other fixed costs.

Four studies reviewed in the meta-analysis quantify values for integration costs that ranged from $1.00/MWh to $5.00/MWh. Several studies rely on existing literature to either estimate their integration costs or reference findings with modifications based on assumptions about PV penetration levels.[61] Existing literature discussed in the selection of studies as a basis for integration cost include:

- A 2014 study by PNNL prepared for Duke Energy on PV integration in the Carolinas, which estimates integration costs in the range of $1.43/MWh to $9.82/MWh based on the level of penetration.[62]
- A 2014 study by Idaho Power to estimate the costs of the operational modifications necessary to integrate intermittent generation from solar plants, which estimates costs ranging from $0.40/MWh to $2.50/MWh for PV capacity ranging from 100 MW to 700 MW.
- A 2013 study prepared by Xcel Energy on the costs and benefits of distributed PV on the Public Service Company of Colorado system.[63]
- The 2014 integrated resource plan of Arizona Public Service, which estimated integration costs on its system of $2.00/MWh in 2020.[64]
- A 2010 New England Wind Integration Study (NEWIS) prepared for ISO-New England by GE, Enernex, and AWS Truepower.[65]

Some studies identify the need for further research and evaluation on the costs of integrating increased solar PV to accurately account for the cost burden on the utility.[66] In California, the LNBA Working Group's report indicates that "bulk-system-level costs" associated with renewable integration are

[60] Stark, Gregory B., P.E. 2015. *A Systematic Approach to Better Understanding Integration Costs.* Golden, CO: National Renewable Energy Laboratory. NREL/TP-5D00-64502. Available at https://www.nrel.gov/docs/fy15osti/64502.pdf.
[61] Beach and McGuire, 2017; Price, et al., 2016; and Norris, et al., 2015.
[62] PNNL, n.d.
[63] Xcel Energy Services, Inc. 2013. *Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System*. Available at http://www.eei.org/issuesandpolicy/generation/NetMetering/Documents/Costs%20and%20Benefits%20of%20Distributed%20Solar%20Generation%20on%20the%20Public%20Service%20Company%20of%20Colorado%20System%20Xcel%20Energy.pdf.
[64] Arizona Public Service (APS). 2014. *Integrated Resource Plan.* Available at http://www.azenergyfuture.com/getmedia/c9c2a022-dae4-4d1b-a433-ec96b2498e02/2014_IntegratedResourcePlan.pdf/?ext=.pdf.
[65] GE Energy. 2010. *New England Wind Integration Study.* Available at https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/newis_report.pdf. NEWIS results were considered in the Maine study (p. 37) as an upper bound on solar integration costs. NEWIS assessed the operational effects of large-scale wind integration in New England, and the Maine analysis assumes that distributed solar will have lower variability than wind because of its more distributed nature.
[66] Whited, et al., 2017; Norris, et al., 2014; New York Department of Public Service (NY DPS), 2016(b); Norris, 2015(a); and Stanton, et al., 2014.

included, but there is no consensus on whether this category should represent costs associated with increasing hosting capacity or facilitating interconnection.[67] Two studies—Vermont and Utah—did not address integration costs.

Societal Values

The decision to include externalities—such as carbon emissions, criteria pollutants, economic development, or other values that accrue to society—can have a significant impact on study results, and agreement was not found across the studies on the inclusion or exclusion of these values. The study from Mississippi describes these externality costs as "environmental damages incurred by society (over and above the amounts 'internalized' in allowance prices)" and indicates that avoided costs from displaced air emissions are "a benefit to the State and can be considered in benefit and cost analysis without necessarily including these non-market costs in an avoided cost rate."[68] Still, the study does not monetize these benefits.

The study from Hawaii describes the issue further: "In general, it is more difficult to obtain consensus on the inclusion or exclusion of environmental components and other societal values. This is partly due to the fact that they are not the utility avoided costs (i.e., they are not expenses incurred by the utility or collected in rates) and partly because the methodologies rely on more speculative assumptions."[69]

Overall, nine studies include societal benefits. The studies from Oregon, Louisiana, Utah, South Carolina, and Georgia explicitly do not include societal benefits. A common rationale for this exclusion is that societal benefits do not accrue as savings in the form of avoided costs to the utility, which means the benefits cannot be passed along to ratepayers. This choice is a general reflection of the perspectives considered in a study.

Carbon Emissions

Most studies include avoided costs to the utility of complying with carbon regulations, either within the avoided energy generation component of the value categories, or a separate category for avoided environmental compliance. However, only some consider the societal value of reduced carbon emissions. Three studies—Arkansas, Maine, and the District of Columbia—calculate societal values related to carbon emissions. Each used the Social Cost of Carbon developed by the U.S. Environmental Protection Agency as a starting point for estimating the value.[70] Table 6 shows the range of values.

Table 6. Range of societal carbon values ($/MWh)

State	Unadjusted Societal Value of Carbon	Dollar Year of Unadjusted Value	Adjusted Value to 2017$
Arkansas	$35.90	2018$	$35.15
Maine	$21.00	2015$	$21.72
District of Columbia	$36.00	2016$	$36.76

[67] California Public Utilities Commission (CPUC), 2017, p. 20.
[68] Stanton, et al., 2014, p. 34.
[69] Norris, 2015(b), p. 14.
[70] The source for estimates of the social cost of carbon is the Federal Government's Interagency Working Group on the Social Cost of Greenhouse Gases. See *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (Updated August 2016). Available at https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf.

Criteria Pollutants and Other Avoided Environmental Costs
Of the nine studies that include societal values for other avoided environmental costs besides carbon, two included values related to criteria pollutants, which tended to be higher than the societal value ascribed to carbon. For example, in the Arkansas study, avoided carbon costs were valued at $35.90/MWh compared to $84.40/MWh for criteria pollutants.[71] Similarly, in the study from Maine, avoided carbon costs were valued at $21.00/MWh compared to $75.00/MWh for criteria pollutants.[72] A few studies discussed other benefits, such as avoided methane leakage, water use, and land use benefits, but only the Arkansas study estimated non-zero values for these categories. The values were $8.00/MWh in reduced methane leakage and $1.20/MWh in avoided water use benefits. Land use benefits were described as "small and positive" but could vary.

Economic Development
The studies from Mississippi and the District of Columbia discussed the societal value of increased economic development, but only the study from Arkansas estimated a non-zero value. In the Mississippi study, economic development benefits, "including job creation and the potential for increased home value," were not monetized because a societal cost test analysis was not performed.[73] The District of Columbia study indicated that increased distributed solar "may contribute new jobs to the District, resulting in reduced unemployment and need for social services while increasing tax revenue," but these benefits were not given a value due to insufficient data.[74] For Arkansas, economic development value was estimated at $33.60/MWh based on an assumption that 22 percent of residential system PV costs are spent in the local economy where the systems are located.[75]

In addition, the study from Louisiana included a solar installation benefits category, which included economic benefits calculated using the Jobs and Economic Development Impact (JEDI) model developed by the National Renewable Energy Laboratories.[76] The study does not differentiate these benefits as societal impacts, but does indicate the portion that is direct, indirect, or induced.

Discount Rate

Discount rates are applied in calculations of the utility's avoided costs and in calculation of societal benefits, if they are included. The higher the discount rate, the lower the value of the long-term benefits of distributed PV and other DERs. For more information on how benefits can be affected by different discount rates, and a summary of the types of discount rates that could be used, see the National Efficiency Screening Project's 2017 *National Standard Practice Manual*.[77]

In general, studies take similar approaches to applying discount rates. For avoided costs from the utility perspective, most studies use a utility-specific weighted average capital cost (WACC) rate as the discount rate. The District of Columbia study was an exception, which found that an alternative discount rate (below Pepco's WACC) was justified because many avoided costs are not capital costs and the

[71] Beach and McGuire, 2017, pp. 26–27.
[72] Norris, et al., 2015, p. 49.
[73] Stanton, et al., 2014, p. 44.
[74] Whited, et al., 2017, p. 151.
[75] Beach and McGuire, 2017, p. 29.
[76] Dismukes, 2015, p. 121.
[77] NESP, 2017, p. 73.

District's policy goals place a strong emphasis on long-term benefits. For avoided costs from the societal perspective, most studies use the societal discount rate of 3 percent in real dollars.

Conclusion

This meta-analysis examines a representative sample of recent studies on the costs and benefits of NEM. It finds that, with widely varying goals and policy contexts, as well as differences in the categories included and the assumptions used, these studies support a range of conclusions regarding NEM policies' net benefits, cost-shifting impacts, and alignment with DER-driven values. The perspective from which value is assessed drives methodology, and decisions on value categories, quantification methods, and input assumptions have significant impacts on findings.

Because the distribution grid and retail service are regulated at the individual State level, it is understandable that there is not one common valuation framework for evaluating the costs and benefits of distributed solar and DER more broadly. That said, we believe that the development of a common set of definitions and categories would help in assisting States, utilities, and other stakeholders to work from a common starting point when endeavoring to determine the net benefit of distributed solar and DER.

Despite these significant methodological differences, the 15 studies analyzed in this paper converge on at least three common value categories, all at the wholesale or bulk power level: avoided energy generation, avoided generation capacity, and avoided transmission capacity. Methodological approaches to calculating these common categories are generally well established, similar, and agreed upon, with the quantified result potentially differing based on a wide range of regional factors and assumptions.

Overall observations from this analysis show, not surprisingly, that a major challenge in studying and developing an approach to NEM, VOS, and DER valuation is that some value components are relatively easy to quantify, while others are more difficult to represent by a single metric or measure. Given the relative newness of evaluating the cost, performance, and therefore net benefit to the distribution grid, the majority of differences between the studies occur in this area. Still, avoided or deferred distribution capacity over a longer term planning horizon is relatively easier to quantify as opposed to the less common value categories that were identified as difficult to calculate or forecast based on data availability or lack of a widely accepted quantification process.

As States and utilities deploy new technologies that can assist in gaining a more detailed understanding of the locational and temporal value of DERs across the electricity system, it will enhance the ability to more accurately assess the costs and benefits of deploying DER on the system. This meta-analysis demonstrates how specific variables, approaches, and assumptions related to the costs and benefits of distributed PV were treated in a selection of studies from a snapshot in time, during a period when frameworks are rapidly evolving and best practices are still being defined.

Appendix A: Summaries of Selected Studies

This section includes short summaries of each study. The summaries follow a standard format, starting with the citation and continuing with three common elements: (1) the study's analytical goal or purpose; (2) any results or answers found in response to the analytical goal; and (3) the takeaways, in bullet form, that are noteworthy for the purposes of the meta-analysis.

Summaries are grouped by type of study and then presented in alphabetical order by State.

Type of Study	States (Prepared by)
NEM Cost-Benefit Analysis	▪ Arkansas (Crossborder) ▪ Louisiana (Acadian) ▪ Mississippi (Synapse) ▪ Nevada (E3) ▪ South Carolina (E3) ▪ Vermont (VT PSD)
VOS/NEM Successor	▪ District of Columbia (Synapse) ▪ Georgia (Southern Company) ▪ Hawaii (CPR) ▪ Maine (CPR) ▪ Minnesota (CPR) ▪ Oregon (CPR) ▪ Utah (CPR)
DER Value Frameworks	▪ California LNBA (CPUC) ▪ New York BCA (DPS Staff)

NEM Cost-Benefit Analysis

Arkansas

Beach, R., and P. McGuire. 2017. *The Benefits and Costs of Net Metering Solar Distributed Generation on the System of Entergy Arkansas, Inc.* Crossborder Energy. Available at https://drive.google.com/file/d/0BzTHARzy2TINbHViTmRsM2VCQUU/view.

This report provides a cost-benefit analysis of "the impacts on ratepayers of the net metering of solar distributed generation [DG] in the service territory of Entergy Arkansas, Inc. (EAI)."[78] The goal of the report is to "contribute to the Commission's review" of net metering issues in response to recent legislation directing the Arkansas Public Service Commission (PSC) to evaluate the rates, terms, and conditions of net metering in Arkansas.[79]

The report concludes that "the benefits of residential DG on the EAI system exceed the costs, such that residential DG customers do not impose a burden on EIA's other ratepayers."[80] The study summarizes the results based on the application of five cost-effectiveness tests (i.e., participant test, RIM test, program administrator cost test, total resource cost test, and societal cost test).

Noteworthy takeaways include:

- The report was commissioned by the Sierra Club and submitted to the Arkansas PSC as part of the *Joint Report and Recommendations of the Net-Metering Working Group* in Docket No. 16-027-R.[81]
- Benefits equal or exceed the costs in the total resource cost, program administrator cost, and societal cost tests.[82]
- The RIM test was used to determine that net metering does not cause a cost-shift to non-participating ratepayers.[83]
- As the cost of integration, the study uses an estimate of "$2 per MWh as the cost of additional ancillary services that may be needed to integrate solar DG into the grid."[84]
- The study found "significant, quantifiable societal benefits" from solar DG.[85]

Louisiana

Dismukes, D. 2015. *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers*. Baton Rouge, LA: Acadian Consulting. Available at http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=f2b9ba59-eaca-4d6f-ac0b-a22b4b0600d5.

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[78] Beach and McGuire, 2017, p. 1.
[79] Act 827 of 2015 tasked the PSC with addressing various issues associated with net metering.
[80] Beach and McGuire, 2017, p. 2.
[81] Arizona Public Service (APS). 2017. *Joint Report and Recommendations of the Net-Metering Working Group*. Docket 16-027-R-Doc. 228. Available at http://www.apscservices.info/pdf/16/16-027-R_228_1.pdf.
[82] Ibid., p. 3.
[83] Ibid.
[84] Ibid., p. 2.
[85] Ibid., p. 4.

The goal of this report is "to quantify the impacts and implications of NEM policies currently being used by the Louisiana Public Service Commission [LPSC] for smaller scale residential and commercial solar energy installations." Three different empirical models are used to estimate the impacts on the ratepayers of LPSC-regulated utilities: a benefit-cost analysis, a cost of service analysis, and an analysis of the income levels of customers installing solar NEM systems.

The cost-benefit analysis was the primary focus in this meta-analysis. It concludes that "the estimated costs associated with solar NEM installations outweighs their estimated benefits."[86] For instance, costs are 1.5 times higher than benefits under the baseline scenario, resulting in negative total net benefits to LPSC ratepayers of $89 million in net present value (NPV) terms.[87]

Noteworthy takeaways include:

- The study looked at three scenarios: (1) a baseline condition including just solar NEM installations to date, (2) a condition in which NEM installations would grow at their historic rate until the installed capacity reached a mandated cap of 0.5 percent of system peak for each utility and then remained flat, and (3) a case in which NEM installations grow unbounded at the utility-specific 2012–2013 growth rate until 2017, after which growth rates slow to 10 percent per year until 2020 as a result of the tax credit phase-out.
- The study also performs three sensitivity analyses (i.e., high natural gas price, high electric capacity price, and carbon price) to test for conditions under which NEM would result in ratepayer benefits. The sensitivities did not shift the results in a direction that was favorable for ratepayers.[88]
- Avoided energy benefits are substantially greater than avoided capacity benefits due to the low effective capacity VOS in Louisiana. Avoided capacity benefits represent the third largest source of benefits.[89]
- Avoided T&D benefits are relatively small, at less than $1 million, because the unit cost of avoided T&D is smaller than generation, and the effective capacity of solar NEM is relatively small.[90]
- Direct, indirect, and induced "solar installation impacts represent the single largest source of total NEM program benefits." These benefits are modeled using the Jobs and Economic Development Impact (JEDI) solar PV model developed by NREL.[91]

Mississippi

Stanton, E.; J. Daniel; T. Vitolo; P. Knight; D. White; and G. Keith. 2014. *Net Metering in Mississippi: Costs, Benefits, and Policy Considerations.* Cambridge, MA: Synapse Energy Economics, Inc. Available at https://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf.

[86] Dismukes, 2015, p. ii.
[87] Ibid., p. 186.
[88] Ibid.
[89] Ibid., p. 131.
[90] Ibid.
[91] Ibid., pp. 122, 132.

This report provides a description of a potential net metering policy for Mississippi and the issues surrounding it, focusing on residential and commercial rooftop solar. The report models and analyzes the impacts of installing rooftop solar equivalent to 0.5 percent of the State's peak historical demand, with a goal of estimating the potential benefits and costs of a hypothetical net metering program.

The report concludes that "net metering provides net benefits under almost all of the scenarios and sensitivities analyzed."[92]

Noteworthy takeaways include:

- At the time the report was prepared, Mississippi was one of five States without a net metering policy.[93]
- Of the value categories considered, the study finds that avoided energy costs provided the greatest benefit, followed by avoided T&D costs, and the value associated with reduced risk.
- Reduced risk includes transmission costs, T&D losses, fuel prices, and other costs. A 10 percent adder was applied to calculate avoided costs in the study.[94]
- In sensitivity analyses, variations in avoided T&D cost generated the most noticeable impact on the benefits of NEM. Projected capacity value and projected CO_2 costs had some impact, while fuel prices had a minor impact.[95]
- Of the cost-effectiveness tests used for energy efficiency in Mississippi (the TRC, RIM, and UCT), the study finds that the TRC test best reflects and accounts for the benefits of distributed generation. The authors do not recommend the use of the RIM test to analyze the efficacy of NEM.[96]
- Generation from rooftop solar panels in Mississippi will most likely displace generation from the State's peaking resources—oil and natural gas combustion turbines.[97]
- Results show that NEM participants would need to receive a rate beyond average retail in order to pursue NEM and suggest that policymakers consider an alternative to NEM, such as a solar tariff structure similar to Minnesota and the Tennessee Valley Authority.[98]

Nevada

Price, S.; Z. Ming; A. Ong; and S. Grant. 2016. *Nevada Net Energy Metering Impacts Evaluation 2016 Update.* San Francisco, CA: Energy and Environmental Economics, Inc. Available at http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2016-8/14264.pdf.

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[92] Stanton, et al. 2014, pp. 2–3. See graph summarizing finding on p. 5.
[93] Walton, Robert. December 7, 2015. "Mississippi regulators approve state's first net metering plan." Utility Dive. Available at https://www.utilitydive.com/news/mississippi-regulators-approve-states-first-net-metering-plan/410341/.
[94] Stanton, et al. 2014, p. 30. For the purposes of the meta-analysis, this value is reflected in the "Fuel Hedging" category; however, it is noteworthy that the component is intended to include additional factors.
[95] Ibid., pp. 45–47.
[96] Ibid., p. 41.
[97] Ibid., pp. 1, 21.
[98] Ibid., p. 50.

This report provides an update to the 2014 report, *Nevada Net Energy Metering Impacts Evaluation*, which calculated the costs and benefits of renewable generation systems under the State's NEM program.

The goal is to "investigate the impact of existing NEM PV systems as well as the projected impact of future NEM PV systems," following the same methodological framework as the 2014 report, but incorporating the most up-to-date utility data. It evaluates the cost-effectiveness of NEM from five different perspectives to assess the costs and benefits of the NEM program.

The report concludes with the following base case results for each of the five perspectives of cost-effectiveness:

- Participant Cost Test (PCT): Solar is not cost-effective for customers who install PV systems; however, the net cost to participating customers is relatively small, at $0.02/kWh, for existing systems.[99]
- Ratepayer Impact Measure (RIM): There is a cost-shift from NEM customers to non-participating customers that amounts to a levelized cost of $0.08/kWh for existing installations.[100]
- Program Administrator Cost Test (PACT): Existing and future NEM systems cause total bills collected by NV Energy to decrease.[101]
- Total Resource Cost (TRC) Test: NEM generation increases total energy costs for Nevada at a net cost to the State of $0.13/kWh for existing systems.[102]
- Societal Cost Test (SCT): The societal perspective does not significantly change the results for the costs and benefits of NEM overall.[103]

Noteworthy takeaways include:

- The finding that NEM generation is a costlier approach is mainly due to utility-scale solar power purchase agreement prices having dropped precipitously in recent years, which greatly lessens the costs avoided by NEM generation, while distributed solar costs have not dropped commensurately.[104]

South Carolina

Patel, K.; Z. Ming; D. Allen; K. Chawla; and L. Lavin. 2015. *South Carolina Act 236: Cost Shift and Cost of Service Analysis*. San Francisco, CA: Energy and Economics, Inc. Available at http://www.regulatorystaff.sc.gov/electric/industryinfo/Documents/Act%20236%20Cost%20Shifting%20Report.pdf.

The goal of this report is "to investigate and report to the Public Service Commission of South Carolina the extent to which cost shifting can be attributed to DER adoption within current rate making practices." The cost-shifting analysis examines the effects of NEM in the context of three scenarios:

[99] Price, et al., 2016, p. 6.
[100] Ibid., p. 7.
[101] Ibid., p. 8.
[102] Ibid., p. 9.
[103] Ibid., p. 10.
[104] Ibid., p. 13.

(1) historical DER adoption, (2) future DER adoption without utility incentives offered through DER programs, and (3) future DER adoption with incentives from DER program participation.

The report concludes that prior to Act 236, NEM-related cost-shifting was *de minimus* due to the low number of participants.[105] Furthermore, it states that "if utilities were to reach the DER adoption targets set in Act 236 without additional incentives, the cost shifting would be small and difficult to isolate." Finally, the report finds that "although more data is required to draw widespread conclusions, the utilities rate structures may need to evolve to be more economically efficient and to alleviate the potential for cost shifting or for uneconomic bypass of the utilities fixed cost recovery. Specifically, fixed charges may need to increase or alternative rate designs may need to be considered."[106]

Noteworthy takeaways include:

- This report evaluates the impacts of DER in the South Carolina Electric and Gas, Duke Energy Carolinas, and Duke Energy Progress service territories.
- The study used three scenarios—low value, base value, and high value—"to capture the uncertainty associated with the future value of DER."[107] The low-value scenario is based on fewer components in the methodology (avoided energy and avoided losses). The base-value scenario "includes most components" (avoided energy, avoided losses, avoided ancillary services, avoided T&D capacity, and avoided criteria pollutants). The high-value scenario includes all of the components in the base-value scenario and approximates a value for a carbon cost placeholder.
- The report was presented to the Office of Regulatory Staff to fulfill its requirements for South Carolina's 2008 Distributed Energy Resource Program Act (Act 236).

Vermont

Vermont Public Service Department (PSD). 2014. *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 99 of 2014.* Available at http://publicservice.vermont.gov/sites/dps/files/documents/Renewable_Energy/Net_Metering/Act%2099%20NM%20Study%20FINAL.pdf.

The goal of this report is to address a legislative request directing the Public Service Department to "complete an evaluation of net metering in Vermont." It provides background describing changes to net metering contained in Act 99 of 2014, and the current status and pace of net metering deployment in Vermont. It includes an updated analysis of the existence and magnitude of any cross subsidy created by the current net metering program pursuant to Act 125 of 2012. It also provides guiding principles for net metering program design based on a review of recent literature.

The "analysis of the existence and degree of potential cross-subsidy" was the primary focus in this meta-analysis. It concludes that "the aggregate net cost over 20 years to non-participating ratepayers due to net metering under the current policy framework is close to zero, and there may be a net benefit."

[105] Patel, et al., 2015, p. ii.
[106] Ibid.
[107] Ibid., p. 12.

Noteworthy takeaways include:

- Based on an analysis of the differences among utilities, which found that winter-peaking utilities will incur a larger share of costs, Vermont PSD recommends that the Board consider whether changes to the current program structure to allow flexibility for the program to vary by utility would better serve the State.[108]
- The report presented the results for six types of systems:
  - 4-kW fixed solar PV system, net metered by a single residence
  - 4-kW two-axis tracking solar PV system, net metered by a single residence
  - 4-kW wind generator, net metered by a single residence
  - 100-kW fixed solar PV system, net metered by a group
  - 100-kW two-axis tracking solar PV system, net metered by a group
  - 100-kW wind generator, net metered by a group
- The report provides results from the perspective of the ratepayer and a statewide/societal perspective. The ratepayer perspective uses a higher discount rate (7.44 percent) and includes a renewable energy credit (REC) value. The statewide/societal calculation uses a lower discount rate (4.95 percent), includes avoided externalized greenhouse gas costs, and does not include a REC value.[109]

VOS/NEM Successor

District of Columbia

Whited, M.; A. Horowitz; T. Vitolo; W. Ong; and T. Woolf. 2017. *Distributed Solar in the District of Columbia: Policy Options, Potential, Value of Solar, and Cost-Shifting.* Cambridge, MA: Synapse Energy Economics, Inc. Available at http://www.synapse-energy.com/sites/default/files/Distributed-Solar-in-DC-16-041.pdf.

This report provides both a VOS study framework (Part III) and a cost-shifting analysis (Part IV). The goal of the VOS study framework is "to determine the value of solar to the utility system and all electric customers in the District," using a "cost-benefit analysis in which all relevant costs and benefits are quantified and analyzed."[110] The goal of the cost-shifting analysis is to conduct a long-term rate impact analysis to understand the effects of cost-shifting from distributed solar customers to non-solar customers, which result in higher bills for non-solar customers.[111] It is "related to the value of solar conducted in Part III, but is a separate analysis that provides an entirely different perspective on customer impacts stemming from distributed solar."

The report concludes that "the utility system total value of solar for 2017–2040, when levelized with a 3 percent discount rate, is $132.66/MWh (2015$)." The societal total VOS for the same time period and

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[108] Vermont Public Service Department (PSD). 2014. *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 99 of 2014*. p. 28. Available at http://publicservice.vermont.gov/sites/dps/files/documents/Renewable_Energy/Net_Metering/Act%2099%20NM%20Study%20FINAL.pdf.
[109] Ibid., p. 16.
[110] Whited, et al., 2017, p. 115.
[111] Ibid., p. 157.

discount rate is $194.40/MWh.[112] The cost-shifting analysis concludes in the base-case scenario that "the typical residential non-solar customer in the District would experience an additional cost of $0.28 per year on average due to distributed solar." In all cases examined, the study finds that "cost-shifting remains relatively modest at less than $1.00 annual impact per residential customer."113

Noteworthy takeaways include:

- Eighteen value categories of potential costs and benefits associated with solar PV are considered. Sixteen were categorized as "utility system" impacts, meaning that the cost or benefit affects all customers in the utility system. Two categories (outage frequency duration and breadth, and social cost of carbon) were deemed "societal" in that they also impact people outside of the District.[114]
- The results are "highly dependent on future gas prices." The avoided energy category, which includes losses and costs associated with risk, represents about half of the utility VOS (and more than a third of the societal value).[115]
- The societal VOS is "quite dependent on the social cost of carbon," which represents a quarter of total societal value.[116]
- The report recommends a continuous update of the VOS model, acknowledging that as solar penetration increases above 10 percent of peak load, so does the likelihood that integration costs will increase.

Georgia

Southern Company. 2017. *A Framework for Determining the Costs and Benefits of Renewable Resources in Georgia.* Revised May 12, 2017. Available at http://www.psc.state.ga.us/factsv2/Document.aspx?documentNumber=167588.

This report provides a framework for determining the costs and benefits of renewable resources on the Southern Company electric system, known as the Renewable Cost Benefit (RCB) Framework. The goal of the report is to describe the RCB Framework and how it will be used, specifically related to the Georgia Power Company. The report considers 23 cost-benefit components for potential inclusion in the RCB Framework, defines and discusses each component, and makes a recommendation on whether the component should be included as a cost or a benefit. The framework provides a methodology to calculate some of the components.

The report finds 18 "in-scope renewable cost benefit components."[117]

Noteworthy takeaways include:

[112] Ibid., p. 10.
[113] Ibid., p. 14.
[114] Ibid., p. 10.
[115] Ibid., p. 12.
[116] Ibid.
[117] Ibid.

- The document recognizes five different categories of solar to differentiate the type being evaluated (i.e., utility-scale transmission, utility-scale distribution, distributed greenfield, distributed metered, and distributed behind-the-meter).[118]
- The framework finds five cost categories: distribution operations costs, ancillary services – reactive supply and voltage control, ancillary services – regulation, support capacity (flexible reserves), and bottom-out costs. A sixth category, generation remix, may be either a benefit or a cost.[119]
- The avoided energy cost category includes a number of components and represents the "energy-related costs that are avoided on the Southern Company electric system in any given hour (including components associated with marginal replacement fuel costs, variable operations and maintenance, fuel handling, compliance-related environmental costs, intra-day commitment costs, and transmission losses)."[120]
- The Framework does not include societal costs or other externalities.[121]

Hawaii

Norris, B. 2015(b). *Valuation of Solar + Storage in Hawaii: Methodology.* Prepared for the Interstate Renewable Energy Council (IREC) by Clean Power Research. Available at http://www.irecusa.org/wp-content/uploads/2015/06/IREC-Valuation-of-Solar-Storage-in-HI_Methodology_2015.pdf.

The goal of this report is to provide a preliminary "methodology that could be used to value solar energy coupled with battery storage in Hawaii."[122] The methodology is "intended to estimate the value (i.e., the net benefits minus costs, which accrue to the utility and its customers from grid connected, behind-the-meter distributed hybrid solar/storage resources." The report "proposes a strawman of benefit categories" and an overview of the computation of those categories.[123]

The report concludes that the methodology "advances the prior art developed for solar-only valuation studies," and if certain new elements related to hybrid resources are incorporated, "a state-of-the-art evaluation could be performed that would determine the benefit provided by solar energy dispatched after sundown to meet Hawaii's evening peak."[124]

Noteworthy takeaways include:

- The study draws extensively on methods used to value solar-only resources, but adds requirements to incorporate storage.
- An estimate of the benefits of distributed solar alone (including energy benefit and other benefits) is not included. However, the study suggests that readers could "suppose the benefit

118 Southern Company, 2017, p. 3.
119 Ibid.
120 Ibid., p. 7.
121 Ibid., p. 30.
122 Norris, 2015(b), p. 1.
123 Ibid., p. 10.
124 Ibid., p. 21.

of solar alone is $0.20 per kWh." Then the analysis suggests that "net generation coming from the hybrid system would have a value of $0.20 + $0.103 = $0.303 per kWh."[125]

- The study suggests a more comprehensive analysis, "including the use of actual utility system load and cost data, a model of hourly dispatch, and other factors rather than the simplified assumptions," is required. The study serves as an example to give a rough approximation.[126]
- Frequency regulation is included as a benefit and identified as a value component that "has not been included in solar-only studies" but indicates that "storage has the ability to charge and discharge in response to signals from the grid operator in order to help regulate frequency."[127]
- The Avoided Distribution Capacity Cost category "may be problematic for Hawaii because HECO [Hawaiian Electric Company] is facing the possibility of cost increases in order to support solar in the distribution system."[128]

Maine

Norris, B.; P. Gruenhagen; R. Grace; P. Yuen; R. Perez; and K. Rabago. 2015. *Maine Distributed Solar Valuation Study.* Prepared for the Maine Public Utilities Commission by Clean Power Research, Sustainable Energy Advantage, LLC, and Pace Law School Energy and Climate Center. Available at http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-FullRevisedReport_4_15_15.pdf.

This goal of this report is to provide a methodology to value distributed solar for three utility territories in Maine: Central Maine Power, Emera Maine's Bangor Hydro District, and Maine Public District. The report concludes the overall value of distributed PV is $0.337/kWh.[129]

Noteworthy takeaways include:

- The distributed PV value is calculated for a set of benefit-cost categories for Central Maine Power and levelized over 25 years. Levelized results for the other two utility service territories are not shown.
- The results indicate that the levelized value of avoided market costs (including energy supply, transmission delivery, and distribution delivery) is lower than the levelized value of societal benefits (net social cost of carbon, SOx and NOx, market price response, and avoided fuel price uncertainty).
- Avoided energy costs, market price response, and net social cost of SOx deliver the largest values.
- Market price response and avoided fuel price uncertainty are included as societal benefits.
- This study includes placeholders for three value components:
  - Avoided natural gas pipeline costs, not included but left as a future placeholder if the cost of building future pipeline capacity is built into electricity prices

[125] Ibid., p. 3.
[126] Ibid.
[127] Ibid., p. 16. The inclusion of frequency regulation in this study is represented in the meta-analysis within the broader category of "ancillary services." However, it is noteworthy that the value was only included as a value component because of the storage element.
[128] Ibid., p. 12.
[129] Norris, et al., 2015. See summary table on p. 56.

- Avoided distribution capacity cost, not included but left as a future placeholder if the peak distribution loads begin to grow (requiring new capacity)
- Avoided costs of voltage regulation, not included but left as a future placeholder if new interconnection standards come into existence, allowing inverters to control voltage and provide voltage ride-through to support the grid

Minnesota

Norris, B.; M. Putnam; and T. Hoff. 2014. *Minnesota Value of Solar: Methodology.* Prepared for the Minnesota Department of Commerce, Division of Energy Resources by Clean Power Research. Available at https://www.cleanpower.com/wp-content/uploads/MN-VOS-Methodology-2014-01-30-FINAL.pdf.

This report provides the methodology to be used by Minnesota utilities adopting a VOS tariff as an alternative to net metering. The goal of the VOS tariff is "to quantify the value of distributed PV electricity." The report provides the methodology and details each step of the calculation.

The report concludes that the methodology can be used to develop a credit for solar customers. An example calculation shows a value of $0.135/kWh.

Noteworthy takeaways include:

- This study was commissioned in response to 2013 legislation and provides an optional alternative compensation mechanism for utilities to adopt customer-owned distributed PV in place of current NEM.
- Some of the value components correspond to minimum statutory requirements, including "the value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value."[130]
- Any "non-required components" were selected only if they were based on known and measurable evidence of the cost to the utility.[131]
- The tariff is updated annually for enrolling customers based on new PV penetration data.
- The avoided fuel cost value "implicitly includes both the avoided cost of fuel, as well as the avoided cost of price volatility risk that is otherwise passed from the utility to customers through fuel price adjustments."[132]
- In the example calculation, avoided fuel cost contributes to approximately 50 percent of the value.[133]
- Avoided voltage control cost and solar integration cost components are included as placeholders and are "reserved for future updates to the methodology." Solar integration costs are "expected to be small, but possibly measurable."[134]
- Credit for systems installed at "high value locations (identified in the legislation as an option)" is included as optional and is addressed in the "Distribution Capacity Cost" section. This is the value component "most affected by location."[135]

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[130] Norris, et al., 2014, p. 3.
[131] Ibid.
[132] Ibid.
[133] Ibid., p. 49.
[134] Ibid., pp. 40, 3.
[135] Ibid., p. 3.

Oregon

Norris, B. 2015(a). *PGE Distributed Solar Valuation Methodology.* Prepared for Portland General Electric by Clean Power Research. Available at https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2015-08-13-distributed-solar-valuation.pdf?la=en.

The goal of this report is to provide "a methodology to calculate the avoided costs that result from distributed solar production delivered to the Portland General Electric (PGE) distribution system." The resulting methodology is "designed primarily for determining the benefits and costs of the gross energy produced by a PV system prior to netting with local load," and methods for calculating export energy are not included. These considerations should be taken into account when applying this methodology in valuing energy provided by NEM systems.[136]

The report concludes with a methodology that gives a levelized value of distributed solar denominated in dollars per kWh, based on "several distinct value components, each calculated using separate procedures."

Noteworthy takeaways include:

- Avoided energy includes three components: avoided fuel costs, avoided variable O&M cost, and avoided fixed O&M cost.
- For solar integration costs, Clean Power Research recommends that PGE should either estimate a dollar amount per MWh cost using best judgment from the available studies performed elsewhere, develop its own integration cost methodology, or assume that the cost is negligible.[137]
- Clean Power Research does not recommend to PGE whether any of the societal benefits should be included or excluded from a benefit-cost study.[138]
- The treatment of avoided fuel price uncertainty would be different, depending upon metering arrangements. If solar generation is used to serve loads behind-the-meter, then this benefit accrues to the solar customer by avoiding energy purchased from the utility. If the energy is delivered to the grid directly for use by PGE in serving its customers, then the benefit accrues to all customers.[139]
- The study analysis period is 20 years.[140]
- The methodology is concerned primarily with the benefits and costs for distributed solar generation, but also can be modified for use with utility-scale resources (connected to transmission) by eliminating avoided transmission and distribution costs, and the loss savings factor.
- The methodology can be used for other generation technologies other than solar, but it does not include dispatch strategies or other methods to produce an assumed generation profile. (A profile is needed as an input to the methodology).

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[136] Norris, 2015(a), p. 6.
[137] Ibid., p. 25.
[138] Ibid., p. 36.
[139] Ibid., p. 34.
[140] Ibid., p. 9.

Utah

Norris, B. 2014. *Value of Solar in Utah.* Clean Power Research. Available at https://pscdocs.utah.gov/electric/13docs/13035184/255147ExAWrightTest5-22-2014.pdf.

The goal of this report is to estimate the value of solar in Utah for the territory served by Rocky Mountain Power. The results conclude that the total levelized VOS with all components included is $0.116/kWh, assuming a 25-year system lifetime.

- The value is based on avoided utility costs from the electricity produced by distributed PV.
- The VOS is the sum of six value categories: fuel, plant O&M, generation capacity, T&D capacity, avoided environmental costs (compliance), and fuel price guarantee value.
- The value does not include societal benefits "because they do not represent savings to the utility."
- The value represents the "long term contract rate at which a utility would be economically indifferent, based on the assumptions of this study. In other words, if a utility were to credit customers with a fixed amount of $0.116 per kWh produced by distributed PV over 25 years, the amount paid would offset the savings to the utility in generating and delivering the energy to the customer."[141]
- Utah Clean Energy and Rocky Mountain Power provided economic and technical assumptions and data.
- The analysis is performed in separate steps. First, the economic value is calculated based on perfect load match and no losses. The result is then modified using "Load Match" factors (based on ELCC) to reflect the match between PV production profiles and utility loads. Finally, a "Loss Savings" factor is applied to reflect the distributed nature of the resource.

DER Value Frameworks

California

California Public Utilities Commission (CPUC). 2016(a). *Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B.* Rulemaking 14-08-013. Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769. Available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M161/K474/161474143.PDF.

California Public Utilities Commission (CPUC). 2016(b). *Decision Adopting Successor to Net Energy Metering Tariff.* Rulemaking 14-07-002. Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering. January 28. Available at http://www.cpuc.ca.gov/General.aspx?id=3934.

California Public Utilities Commission (CPUC). 2017. *Locational Net Benefit Analysis Working Group Final Report.* Rulemaking 14-08-013. Order Instituting Rulemaking Regarding Policies and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code 769, and Related Matters.

[141] Norris, 2014, p. 12.

March 8. Available at http://drpwg.org/wp-content/uploads/2016/07/R1408013-et-al-SCE-LNBA-Working-Group-Final-Report.pdf.

These documents detail the most recent and significant decisions related to development and use of the Locational Net Benefit Analysis (LNBA) methodology to assess the costs and benefits of distributed solar in California. All three were reviewed for this meta-analysis. The first document provides the final report of the LNBA Working Group, a group established by CPUC with a goal of developing a methodology for investor-owned utilities to use to value DERs. The second document provides the Assigned Commissioner's Ruling, which refined and authorized the use of the LNBA methodology by utilities for demonstration projects. The third document reflects CPUC's decision to adopt a NEM successor tariff.[142]

Noteworthy takeaways include:

- In May 2016, a few months after the NEM successor tariff was adopted, CPUC approved use of the LNBA methodology in the utility's Distribution Resource Planning (DRP) Demonstration B projects.
- Some of the LNBA value categories already existed in the Distributed Energy Resources Avoided Cost Calculator (DERAC) used to calculate the cost-effectiveness of utility energy efficiency programs. CPUC adjusted DERAC and updated certain value categories, such as energy and capacity, with more location-specific inputs via locational marginal price.
- Policymakers continue to work toward approving a uniform LNBA tool. CPUC is expected to review the NEM successor tariff in 2019 and explore compensation structures other than NEM.
- In their final report, the LNBA Working Group requested clarification from CPUC on "how 'integration costs' should be captured in the tool."[143]

New York

New York Department of Public Service (NY DPS). 2016(a). *Order Establishing the Benefit Cost Analysis Framework. Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.* January 21. Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bF8C835E1-EDB5-47FF-BD78-73EB5B3B177A%7d.

New York Department of Public Service (NY DPS). 2016(b). *Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding. Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program. CASE 15-E-0082.* October 27. Available at https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&cad=rja&uact=8&ved=0ahUKEwij59DitKrXAhUq6YMKHQYsBZIQFggoMAA&url=http%3A%2F%2Fdocuments.dps.ny.gov%2Fpublic%2FCommon%2FViewDoc.aspx%3FDocRefId%3D%257B59B620E6-87C4-4C80-8BEC-E15BB6E0545E%257D&usg=AOvVaw3i5PwEpAeHYti_MhoW1BZ7.

[142] The NEM successor tariff (NEM 2.0) decision was adopted in January 2016 and established utility-specific interconnection fees for customer-sited DG, modified non-bypassable charges and rules related to system size, and changed NEM customers over to time-of-use rates.
[143] California Public Utilities Commission (CPUC), 2017, p. 18.

These documents provide the most recent decisions within the New York Reforming the Energy Vision (REV) proceeding related to development and use of a benefit-cost analysis (BCA) framework for utilities to evaluate DER alternatives. Both were reviewed for this meta-analysis.

The first document establishes the BCA Framework that guided utilities in developing their own, individual BCA Handbooks. The goal of the BCA Framework is to provide consistent statewide methodologies for calculating the benefits and costs of DER investments.

The second document provides the DPS staff's recommendations to establish the Phase One Value of DER (VDER) methodology, which transitions away from the traditional NEM model. It provides the basis for a "Value Stack" tariff, under which compensation is calculated using the readily quantifiable DER values from the BCA Framework.

Noteworthy takeaways include:

- The VDER methodology uses a more limited set of value categories than the BCA Framework. Five categories make up the Value Stack: energy, capacity, environmental, demand reduction, and locational system relief value.
- Staff recommendations identify some value categories that may be added in a later phase of the effort, including other distribution system values not reflected in the demand reduction value, reduced SO_2 and NOx emissions, non-energy benefits, environmental justice impacts, and wholesale price suppression.
- Subsequent versions of utility BCA Handbooks are expected to have greater locational and temporal granularity.

Appendix B: List of Possible Studies to Include

This appendix contains the full list of literature considered for inclusion in the meta-analysis. The list was compiled in November 2017. A check mark in the last column indicates whether the document was included in the meta-analysis. Note that more than one document was reviewed in New York and California as a reflection of ongoing and interrelated regulatory activities.

Title	Year	Sponsor	Prepared by	Included
The Benefits and Costs of Net Metering Solar Distribution Generation on the System of Entergy Arkansas	2017	Sierra Club	Crossborder Energy	√
Value of Solar Study: Distributed Solar in the District of Columbia	2017	Office of the People's Counsel	Synapse Energy Economics	√
A Framework for Determining the Costs and Benefits of Renewable Resources in Georgia	2017	Georgia Power	Georgia Power	√
Solar Energy in Michigan: The Economic Impact of Distributed Generation on Non-Solar Customers	2017	Institute for Energy Innovation	Institute for Energy Innovation	
PUCO Order – Investigation to Determine the Resource Value of Solar	2017	Public Utility Commission of Oregon	Public Utility Commission of Oregon	
Locational Net Benefit Analysis Working Group Final Report, Rulemaking 14-08-013, Order Instituting Rulemaking Regarding Policies and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code 769, and Related Matters, March 8	2017	California Public Utility Commission (CPUC)	Locational Net Benefit Analysis (LNBA) Working Group	√
Testimony – Value of Distributed Generation in Arizona	2016	The Alliance for Solar Choice	Crossborder Energy	
Decision Adopting Successor to Net Energy Metering Tariff, Rulemaking 14-07-002, Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering	2016	CPUC	CPUC	√
Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B, Rulemaking 14-08-013, Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769	2016	CPUC	CPUC	√
PV Valuation Methodology Recommendations for Regulated Utilities in Iowa	2016	Midwest Renewable Energy Association	Clean Power Research	

Title	Year	Sponsor	Prepared by	Included
PV Valuation Methodology Recommendations for Regulated Utilities in Michigan	2016	Midwest Renewable Energy Association	Clean Power Research	
Nevada Net Energy Metering Impacts Evaluation 2016 Update	2016	State of Nevada Public Utilities Commission	Energy and Environmental Economics (E3)	√
Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding; Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program, Case 15-E-0082, New York Department of Public Service	2016	NY Public Service Commission	NY Department of Public Service Staff	√
Order Establishing the Benefit Cost Analysis Framework, Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, State of New York Public Service Commission	2016		NY Public Service Commission	√
PV Valuation Methodology Recommendations for Regulated Utilities in Wisconsin	2016	Midwest Renewable Energy Association	Clean Power Research	
Valuation of Solar + Storage in Hawaii: Methodology	2015	Interstate Renewable Energy Council	Clean Power Research	√
Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers	2015	Louisiana Public Service Commission	Acadian Consulting Group	√
Value of Distributed Generation: Solar PV in Massachusetts	2015	Acadia Center	Acadia Center	
Maine Distributed Solar Valuation Study	2015	Maine Public Utility Commission	Clean Power Research	√
Net Metering in Missouri: The Benefits and the Costs	2015	Missouri Energy Initiative	Missouri Energy Initiative	
Shining Rewards: The Value of Rooftop Solar Power for Consumers and Society	2015	Frontier Group and Environment America Research & Policy Center	Frontier Group and Environment America Research & Policy Center	
Distributed Generation-Integrated Value (DG-IV): A Methodology to Value DG on the Grid	2015	Tennessee Valley Authority		
The Benefits and Costs of Net Energy Metering in New York	2015	E3		
PGE Distributed Solar Valuation Methodology	2015	Portland General Electric	Clean Power Research	√
South Carolina Act 236: Cost Shift and Cost of Service Analysis	2015	South Carolina Office of Regulatory Staff	E3	√

Title	Year	Sponsor	Prepared by	Included
Value of Distributed Generation: Solar PV in Vermont	2015	Acadia Center	Acadia Center	
Minnesota Value of Solar: Methodology	2014	Minnesota Department of Commerce	Clean Power Research	√
Net Metering in Mississippi	2014	Public Service Commission of Mississippi	Synapse Energy Economics	√
Value of Solar in Utah	2014	Utah Clean Energy	Clean Power Research	√
Evaluation of Net Metering in Vermont Conducted Pursuant to Act 99 of 2014	2014	Public Service Department (PSD)	PSD	√
2013 Updated Solar PV Value Report	2013	Arizona Public Service Company	SAIC	
The Benefits and Costs of Solar Distributed Generation for Arizona Public Service	2013		Crossborder Energy	
Introduction to the California Net Energy Metering Ratepayer Impacts Evaluation	2013	CPUC	E3	
Evaluating the Benefits and Costs of Net Energy Metering for Residential Customers in California	2013	Vote Solar Initiative	Crossborder Energy	
Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System	2013	Xcel Energy Services	Xcel Energy Services	
A Review of Solar PV Benefits & Costs Studies	2013	Rocky Mountain Institute		
The Benefits and Costs of Solar Generation for Electric Ratepayers in North Carolina	2013	North Carolina Sustainable Energy Association	Crossborder Energy	
2014 Value of Solar at Austin Energy	2013	Austin Energy	Clean Power Research	
The Value of Distributed Solar Electric Generation to San Antonio	2013	U.S. DOE SunShot Initiative	Clean Power Research and Solar San Antonio	
Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California	2012	U.S. DOE Office of Energy Efficiency & Renewable Energy and Office of Electricity Delivery & Energy Reliability	Lawrence Berkeley National Laboratory	
Technical Potential for Local Distributed Photovoltaics in California, Preliminary Assessment	2012	CPUC	E3	

Title	Year	Sponsor	Prepared by	Included
The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania	2012	The Mid-Atlantic Solar Energy Industries Association and The Pennsylvania Solar Energy Industries Association	Clean Power Research	
The Potential Impact of Solar PV on Electricity Markets in Texas	2012	Solar Energy Industries Association and The Energy Foundation	The Brattle Group	
Designing Austin Energy's Solar Tariff Using a Distributed PV Calculator	2012	Austin Energy	Clean Power Research and Austin Energy	

Appendix C: Input Assumptions for Displaced Marginal Unit

State	Marginal Unit	Detailed Assumptions (Avoided Energy)	Page No. From Study
Arkansas	Gas-fired generation, uses MISO LMPs	"Solar DG on the EAI [Entergy Arkansas, Inc.] system avoids marginal generation, **principally gas-fired generation** in the MISO [Midcontinent] South market area. To estimate these avoided costs, we have used **recent MISO locational marginal prices (LMPs)** for the Arkansas Hub, weighted by a standard output profile for a solar array in Little Rock, and escalated these LMPs using the long-term forecast of natural gas prices from the Energy Information Administration's (EIA) *Annual Energy Outlook 2017* (AEO 2017)."	p. 9
California	Uses DERAC values; option to use LMP prices	In the approved LNBA [Locational Net Benefit Analysis] Methodology Requirements Matrix for Demonstration Project B, utilities are required to "**use DERAC values**," also known as the 2016 Distribution Energy Resource Avoided Calculator or 2016 Avoided Cost Model.[144] "For the secondary analysis, the IOUs [independently owned utilities] may also estimate the avoided cost of energy using **locational marginal prices (LMPs)** for a particular location, as per the method described in SCE's [Southern California Edison's] application."	p. 27, CPUC, 2016(a)
District of Columbia	Uses PJM LMPs	"To calculate the total avoided energy benefit across each year, we correlate each hour's generation in PVWatts to a system marginal energy cost, based on historical data for the PJM Interconnect for 2015. This study **uses 2015 locational marginal prices for the PEPCO zone of PJM** …" and "For future years, we assume these prices follow the trajectory of regional electricity generation system prices within EIA's *Annual Energy Outlook* (AEO) 2016, released in September 2016."	p. 128
Georgia	Uses hourly production cost model	"… Avoided Energy Cost used in the Framework reflects the projected fuel and technology expected to represent the marginal unit for dispatch in any given hour in which the renewable resource is expected to be producing electricity. It does not reflect any specific single fuel or any specific single technology." "Avoided energy cost projections are developed using the Production Cost model. The Production Cost model is a complete electric utility/regional pool analysis and accounting system that is designed for performing planning and operational studies. It is an **hourly production cost model** that has the fundamental goal of minimizing total production cost while providing detailed projections of fuel cost and pool accounting, including individual unit information."	p. 9; p. 49

[144] For more information on how DERAC calculates energy price forecast, see https://drpwg.org/wp-content/uploads/2017/11/LNBA-Item-4.i-Locational-Avoided-Energy-Revised-Proposal.docx.

State	Marginal Unit	Detailed Assumptions (Avoided Energy)	Page No. From Study
Hawaii	Oil-fired generation is predominant; futures for fuel oil would be used	"In the solar-only methodologies, natural gas has been assumed as the displaced fuel. In Hawaii, **oil-fired generation is predominant**, so adjustments would have to be made accordingly. **Futures for fuel oil would be used instead of natural gas**, and transportation to the island would be factored in."	p. 11
Louisiana	Uses natural gas combustion turbine as a proxy for the marginal unit	"Natural gas-fired generating resources have dominated new incremental generation over the past decade and continue to serve as the 'marginal' unit in most regional wholesale power markets given their relatively low capital costs and operating flexibility. Thus, an **advanced natural gas-fired combustion turbine**, with an assumed thermal efficiency of 9,750 British thermal units per kWh (Btu/kWh), serves **as an appropriate proxy for the marginal unit** setting energy prices in wholesale power markets over the next decade, and correspondingly, serves as an appropriate proxy for estimating avoided energy costs. A constant natural gas price of $3.50/MMBtu was used to estimate the fuel component of this avoided energy cost."	p. 112
Maine	Assumes natural gas displacement	"This methodology assumes that **PV displaces natural gas** during PV operating hours. During some hours of the year, other fuels (e.g., oil) may be the fuel on the margin. In these cases, natural gas displacement is a simplifying assumption that is not expected to materially impact the overall value."	p. 19
Minnesota	Assumes natural gas displacement	"This methodology assumes that **PV displaces natural gas** during PV operating hours. This is consistent with current and projected MISO market experience. During some hours of the year, other fuels (such as coal) may be the fuel on the margin. In these cases, natural gas displacement is a simplifying assumption that is not expected to materially impact the calculated VOS tariff. However, if future analysis indicates that the assumption is not warranted, then the methodology may be modified accordingly. For example, by changing the methodology to include displacement of coal production, avoided fuel costs may decrease and avoided environmental costs may increase."	p. 5
Mississippi	Assumes displacement of gas and oil peaking resources (combustion turbines)	"Marginal unit: Mississippi's 2013 generation capacity includes 508 MW of natural gas and petroleum oil-based combustion turbines (CTs). While these oil units do not contribute a significant portion of Mississippi's total energy generation, they do contribute to the State's peaking capabilities. On aggregate, these peaking resources operated 335 days in 2013—most frequently during daylight hours—and had a similar aggregate load shape to potential solar resources (see Figure 7). Our benefit and cost analysis follows the **assumption that gas and oil CT peaking resources will be on the margin** when solar resources are available and, therefore, that solar net-metered facilities will displace the use of these peaking resources. At the level of solar penetration explored in our analysis (0.5 percent), it is unlikely that solar resources will displace base load units."	p. 21

State	Marginal Unit	Detailed Assumptions (Avoided Energy)	Page No. From Study
Nevada	Uses hourly marginal wholesale prices, based on production model	"Estimate of **hourly marginal wholesale value of energy**, excluding the regulatory price of carbon dioxide emissions. Source: **Production simulation runs** from NV Energy."	p. 32
New York	Uses LBMPs from the New York Independent System Operator (NYISO)	"To forecast avoided system energy costs, utilities shall use energy price forecasts for the wholesale energy market—**Location Based Marginal Prices (LBMPs**)—from the most recent final version of the NYISO's Congestion Assessment and Resource Integration Study (CARIS) economic planning process Base Case."	p. 5, Appendix C, NY PSC, 2016
Oregon	Assumes natural gas displacement	"This methodology calculates energy value as the avoided cost of fuel and O&M, assuming that **PV displaces natural gas** during PV operating hours. During some hours of the year, other fuels may be the fuel on the margin. In these cases, natural gas displacement is a simplifying assumption."	p. 9
South Carolina	Uses production simulation model based on utility's most recent IRP	"Component is the marginal value of energy **derived from production simulation runs** per the Utility's most recent Integrated Resource Planning (IRP) study and/or Public Utility Regulatory Policy Act (PURPA) Avoided Cost formulation. Based on Utility-provided forecast and E3 analysis."	p. 10
Utah	Assumes displacement of natural gas combustion turbine	"Under this study, the value is defined as the cost of **natural gas fuel** that would otherwise have to be purchased **to operate a gas turbine (CCGT) plant** and meet electric loads and overcome T&D losses. The study presumes that the energy delivered by PV displaces energy at this plant for each hour of the study period with loss calculations being based on each hour."	p. 2
Vermont	Uses hourly marginal wholesale prices, based on ISO-NE	"The Department calculated a hypothetical 2013–14 avoided energy cost on an hourly basis by multiplying the production of real Vermont generators by the **hourly price set in the ISO-NE market**. This annual total value was then updated to 2015 and beyond by scaling the annual total price according to a market price forecast."	p. 11

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STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for authority to increase its rates for the generation and distribution of electricity and for other relief.	))))))	Case No. U-20697

PROOF OF SERVICE

I hereby certify that a true copy of the foregoing *Corrected PUBLIC Direct Testimony and Exhibits of William D. Kenworthy, Kevin Lucas, Claudine Y. Custodio, Dr. Gabriel Chan, Karl R. Rábago, and Ronny Sandoval on behalf of the Ecology Center, the Environmental Law & Policy Center, Great Lakes Renewable Energy Association, the Solar Energy Industries Association and Vote Solar (Joint Clean Energy Organizations or JCEO*) was served by electronic mail upon the following Parties of Record, this 25th day of June, 2020.

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