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Pacific Northwest NATIONAL LABORATORY

Illinois Distributed Generation Rebate – Preliminary Stakeholder Input and Calculation Considerations

October 2018

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U.S. DEPARTMENT OF ENERGY

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Richland, Washington 99352

Executive Summary

What is the value of distributed generation to the distribution system and how do we assign that value to a rebate? This white paper provides a preliminary look at potential distributed generation valuation methodologies and compensation options for Illinois by taking into consideration data needs and availability, stakeholder comments, and Illinois Public Utilities Act language.

Pacific Northwest National Laboratory (PNNL) is supporting the Illinois Commerce Commission (ICC or Commission) with initial stakeholder engagement to advance the conversation around distributed generation valuation in Illinois. PNNL's educational support will help set the stage for a productive formal process as the ICC will be called upon, in potentially relatively short order, to start formal distributed generation valuation proceedings in response to Illinois Public Act 99-0906, also known as the Future Energy Jobs Act (FEJA), and codified in Illinois Public Utilities Act Section 16-107.6. This white paper does not represent the ICC's formal investigation of distributed generation rebate valuation and is not intended to characterize or prejudge any decisions on behalf of the ICC.

From two workshops (March 1, 2018 and July 28, 2018) and subsequent informal written comments, the stakeholder comments covered many topics and addressed different question prompts. Common themes include addressing issues unique to Illinois; having data transparency, privacy, and availability; considering stakeholder engagement processes; the possibility of taking an incremental approach to the valuation; and using alternative or separate compensation mechanisms for some value streams. The primary point of disagreement among stakeholders revolves around what value components should be included in the rebate.

Many stakeholders agreed it was essential not to determine the value of distributed generation to the distribution system in isolation. Some stakeholders noted the distinction between the *investigation* the Commission is required to open when the 3% threshold is hit, and what the *rebate valuation* should finally include. Ultimately, the ICC makes the decision on distributed generation rebate valuation.

Because the law says "the value of such rebates shall reflect the value of the distributed generation…," this white paper primarily focuses on potential valuation components specific to distributed generation, namely avoided distribution capacity costs, reduction in distribution losses, distribution voltage support, and operating reserves, as well as the data needs to assess these types of components and perform the overall valuation.

Other states, such as California, New York, and Minnesota, provide examples of how to address data transparency and privacy issues, stakeholder engagement processes, valuation approaches, and the required data needs to accomplish a valuation. Based on a review of these states' approaches, stakeholder feedback, and stakeholder-suggested approaches, the data types most likely to be needed to best understand the geographic, time-based, and performance-based benefits of distributed generation in Illinois include the following:

- Load growth projections
- System capacity planning studies – from distribution transformer to bulk system sub-transmission
- Existing and projected distributed generation deployment and production by location
- Line loss studies

- System reliability studies (including voltages, protection, phase balancing)
- System-wide and location-specific cost information, including cost information for potential system upgrades
- System-wide and location-specific peak demand growth rates
- Marginal cost of service studies.

Not all of these datasets are readily available, and other states do not have this complete list. The entirety of data necessary for completing the Illinois rebate calculations will become clearer as the valuation components are decided upon. Additional issues will include deciding what analysis methodologies should be used and what data and analyses will be made public. As the ICC and stakeholders work together to develop a distributed generation rebate for Illinois, this white paper can act as a source of reference material and a reminder of some of the generally held stakeholder viewpoints.

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Acronyms and Abbreviations

CPR	Clean Power Research
DDOR	Distribution Deferral Opportunity Report
DER	distributed energy resource
DG	distributed generation
DOE	Department of Energy
DRV	demand reduction value
ELCC	effective load-carrying capacity
FEJA	Future Energy Jobs Act
FERC	Federal Energy Regulatory Commission
GNA	grid needs assessment
ICA	integration capacity analysis
ICC	Illinois Commerce Commission
IPA	Illinois Power Agency
LNBA	locational net benefits analysis
LSRV	locational system relief value
MCOS	marginal cost of service
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
PLR	peak load reduction
PNNL	Pacific Northwest National Laboratory
PUC	public utility commissions
PV	photovoltaics
REC	renewable energy certificate
RGGI	Regional Greenhouse Gas Initiative
RPS	renewable portfolio standard
RVOS	resource value of solar
SETO	Solar Energy Technology Office
VDER	value of distributed energy resource
VOS	value of solar

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1.0 Introduction

This white paper addresses the following questions: What is the value of distributed generation to the distribution system and how do we assign that value to a rebate?

1.1 Report Scope

Pacific Northwest National Laboratory (PNNL), along with Lawrence Berkeley National Laboratory (LBNL) and National Renewable Energy Laboratory (NREL), is collaborating with the U.S. Department of Energy's (DOE) Solar Energy Technology Office (SETO) to provide high-impact research and analysis for state public utility commissions (PUCs) on technical issues related to the integration of solar photovoltaics (PV) and other distributed energy resources (DERs) within the U.S. electricity system.

To that end, PNNL is supporting the Illinois Commerce Commission (ICC or Commission) with initial stakeholder engagement to advance the conversation around distributed generation valuation in Illinois. This assistance will inform the ICC and Illinois stakeholders' understanding of the technical, financial, and policy implications of distributed generation deployment as outlined in Illinois Public Act 99-0906, also known as the Future Energy Jobs Act (FEJA), and codified in Illinois Public Utilities Act Section 16-107.6. PNNL's educational support will help set the stage for a productive formal process, as the ICC will be called upon, in potentially relatively short order, to start formal distributed generation valuation proceedings. This white paper does not represent the ICC's formal investigation of distributed generation rebate valuation, and is not intended to characterize or prejudge any decisions on behalf of the ICC.

1.2 Report Purpose

This white paper provides a preliminary look at potential distributed generation valuation methodologies and compensation options for Illinois by taking into consideration data needs and availability, input received at the March 1, 2018 and July 28, 2018 stakeholder workshops and subsequent informal written comments, and Illinois Public Utilities Act language. Some stakeholder comments are restated or summarized in this white paper, primarily using the original language and terminology of the stakeholders. The full sets of stakeholder comments submitted after each of the two workshops are presented as Appendix D.

This white paper may also be informative to other states and PUCs looking at the value of DERs—one of the objectives of the SETO's analytical support program is to share research findings with stakeholders nationally.

1.3 Context

This section cites key excerpted language from the FEJA and the Illinois Public Utilities Act relevant to the distributed generation rebate valuation.

Future Energy Jobs Act Section 1(a)(1):

…the State should encourage: the adoption and deployment of cost-effective distributed energy resource technologies and devices, such as photovoltaics, which can encourage private investment in renewable energy resources, stimulate economic growth, enhance the continued diversification of Illinois' energy

resource mix, and protect the Illinois environment; investment in renewable energy resources, including, but not limited to, photovoltaic distributed generation, which should benefit all citizens of the State, including low-income households…

Illinois Public Utilities Act Section 16-107.6(e):

When the total generating capacity of the electricity provider's net metering customers is equal to 3%, the Commission shall open an investigation into an annual process and formula for calculating the value of rebates…The investigation shall include diverse sets of stakeholders, calculations for valuing distributed energy resource benefits to the grid based on best practices, and assessments of present and future technological capabilities of distributed energy resources. The value of such rebates shall reflect the value of the distributed generation to the distribution system at the location at which it is interconnected, taking into account the geographic, time-based, and performance-based benefits, as well as technological capabilities and present and future grid needs.

Illinois Public Utilities Act Section 16-107.6(c)(1):

Until the utility files its tariff or tariffs to place into effect the rebate values established by the Commission…The value of the rebate shall be $250 per kilowatt of nameplate generating capacity, measured as nominal DC power output, of a non-residential customer's distributed generation.

Illinois Public Utilities Act Section 16-107.6(b)(4):

The tariff shall also provide for additional uses of the smart inverter that shall be separately compensated and which may include, but are not limited to, voltage and VAR support, regulation, and other grid services.

Illinois Public Utilities Act Section 16-107.6(b)(1):

[Distributed generation] *has a nameplate generating capacity no greater than 2,000 kilowatts and is primarily used to offset that customer's electricity load.*

Illinois Public Utilities Act Section 16-107.5(j):

After such time as the load of the electricity provider's net metering customers equals 5% of the total peak demand supplied by that electricity provider during the previous year, eligible customers that begin taking net metering shall only be eligible for netting of energy.

Illinois Public Utilities Act Section 16-107.6(c)(3):

Upon approval of a rebate application submitted under this subsection (c), the retail customer shall no longer be entitled to receive any delivery service credits for the excess electricity generated by its facility and shall be subject to the provisions of subsection (n) of Section 16-107.5 of this Act.

1.3.1 Distributed Generation and Distributed Energy Resource

The language in Section 16-107.6 includes both the terms "distributed generation" and "distributed energy resources," but the terms are not interchangeable, as distributed generation is one type of DER. Depending on the discussion topic, stakeholders, at times, may use both terms in their comments.

Section 16-107.6 states that "distributed generation" shall satisfy the definition of distributed renewable energy generation device set forth in Section 1-10 of the Illinois Power Agency (IPA) Act. This IPA definition is summarized as a device that is powered by wind, solar thermal energy, PV cells or panels, biodiesel, crops and untreated and unadulterated organic waste biomass, tree waste, and hydropower that does not involve new construction or significant expansion of hydropower dams; is interconnected at the distribution system level; is located on the customer side of the customer's electric meter and is primarily used to offset that customer's electricity load; and is limited in nameplate capacity to less than or equal to 2,000 kilowatts (kW).

A DER, as noted in Ameren Illinois' comments, "is a more widely used term that may better encompass the full breadth of technologies and applications that may be connected to the distribution grid…Ameren Illinois considers a broad definition of DER in which DER is defined to broadly encompass any generation, storage, or other load managing resource connected to the distribution grid" (Ameren 2018a). The Coalition to Request Equitable Allocation of Costs Together (REACT) also noted that a DER, as defined by the North American Electric Reliability Corporation (NREC), is any resource on the distribution system that produces electricity and can include distributed generation, energy storage, DER aggregation, microgrids, and co-generation (REACT 2018b).[1]

1.3.2 Context Interpretations

Because of the different terminology used, the comments revealed different interpretations of the Illinois Public Utilities Act language by different stakeholder parties. While there may be different stakeholder interpretations (restated in this white paper), ultimately the ICC decides on the distributed generation valuation. Because the law says "the value of such rebates shall reflect the value of the distributed generation…," and to keep the scope of this white paper manageable, parts of this white paper primarily focus on the costs and benefits of distributed generation specifically.

1.3.3 Investigation vs. Valuation

The comments also brought to light assertions by some that the Illinois Public Utilities Act language implies that the investigation can be broad to inform the final valuation. Some stakeholders noted the distinction between the *investigation* the Commission is required to open when the 3% threshold is hit, and what the *rebate valuation* should ultimately include. This white paper represents neither the investigation nor the valuation, but provides educational support to inform those processes.

All parties acknowledged that DERs can provide additional benefits beyond those provided to the distribution network. These benefits could be to the environment, society, the larger grid system, and customers (Ameren 2018a; ComEd 2018a; ELPC et al. 2018a; Illinois PIRG 2018a; JSP 2018a; REACT 2018a).

Some parties suggested that the distributed generation rebate valuation process should first consider all the values DERs could provide to the electricity system to assess which should be applicable to the rebate (ELPC et al. 2018a; Illinois PIRG 2018a; JSP 2018a), some parties acknowledged that alternative compensation mechanisms could be utilized to compensate for some of those other benefits not considered applicable (ComEd 2018a; ELPC et al. 2018a; JSP 2018a), and others indicated that the valuation consideration should be limited to the value distributed generation provides to the distribution system only (Ameren 2018; IIEC 2018).

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[1] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy Resources _Report.pdf

These different valuation approaches are explored in subsequent sections of the white paper. The idea of what the scope of the investigation should include compared to what the rebate valuation should include is integral to many stakeholder comments and ideas presented throughout the white paper.

ComEd stated that the Illinois Public Utilities Act language clearly identifies the process for determining the value of distributed generation in Illinois, but acknowledged that determining the value of distributed generation to the distribution system must be done with a holistic perspective and not in isolation in order to prevent potential “double counting” any value components in both the wholesale market and at the distribution level (ComEd 2018a, 2018b). Illinois Industrial Energy Consumers (IIEC) agreed that the rebate should consider value of distributed generation to the distribution system and not an expanded examination of benefits (IIEC 2018).

In their comments, REACT addressed a number of issues they recommend the Commission investigate relative to barriers to DER deployment that could be part of a comprehensive investigation into the value of DER to the grid (REACT 2018a, 2018b). REACT contended that taking a narrow interpretation of the law at this early stage unnecessarily restricts the Commission’s consideration of the breadth of technologies that add value to the grid (REACT 2018b).

Joint Solar Parties noted that the Illinois Public Utilities Act language states both the “value of the distributed generation to the distribution system at the location where it is interconnected” and “benefits to the grid,” so both sets of requirements should be analyzed (JSP 2018a).

ELPC and its partners suggested that the initial investigation be broad and consider all distributed generation values, so the ICC can then decide which values should be compensated through the rebate and which are provided, or should be provided, through other mechanisms (ELPC et at. 2018b).

1.3.4 Net Metering

Currently, most net metering customers in Illinois with excess generation sent back to the grid receive a net metering credit equivalent to the full retail rate. This full retail rate compensation reflects energy, delivery, and transmission costs.

Per Illinois Public Utilities Act Section 16-107.5, once the utility’s 5% cap is reached and the new distributed generation rebate is in effect, *eligible customers that begin taking net metering shall only be eligible for netting of energy;* the credit will reflect the energy supply rate only. With the exception of some grandfathered residential net metering customers that elect to forgo distributed generation rebates, net metering customers will no longer receive any delivery service credits for the excess electricity generated by their facility. In addition, the ICC’s Order in Docket No. 17-0350 concluded that the net metering credit for “electricity produced” should only include credit for the energy supplied (and should not compensate for other types of services, such as transmission service) (ICC 2017). Therefore, customers will also no longer receive a transmission credit as part of their net metering credit.

1.3.5 Smart Inverter

While the IPA’s Long-Term Renewable Resources Procurement Plan refers to the distributed generation rebate of Section 16-107.6 as a “smart inverter rebate,” this characterization is imprecise. While it is true that the law says that new customers who enroll in net metering after June 1, 2017 are required to have a smart inverter to be eligible for the rebate, net metering customers who enrolled prior to that date are also eligible to apply for the rebate without having a smart inverter. Therefore, calling the rebate a smart inverter rebate is technically incorrect.

In addition, the presence of smart inverters significantly changes the impact of distributed generation on the need for or provision of ancillary services, compared to distributed generation installations without smart inverters. Because some grandfathered net metering customers will still be eligible for a distributed generation rebate without a smart inverter, it is possible that the rebate value calculation will be different for systems with smart inverters and without smart inverters.

2.0 Stakeholder Comments

The stakeholder comments covered many topics and addressed different question prompts. Common themes highlighted in this section include addressing issues unique to Illinois; having data transparency, privacy, and availability; considering stakeholder engagement processes; the possibility of taking an incremental approach to the valuation; and using alternative or separate compensation mechanisms for some value streams. The more detailed issues of grading circuits and standardization are also summarized in this section. The primary point of disagreement among stakeholders revolves around what value components should be included in the rebate, as introduced in Sections 1.3.2 and 1.3.3.

2.1 Issues Specific to Illinois

Key issues specific to Illinois that were expressed in stakeholder comments are that the valuation building blocks must consider the deregulated electricity market conditions in the state; compensation is to be in the form of an upfront rebate, rather than generation-based payments; Illinois utilities currently rely on embedded cost of service studies, rather than marginal cost of service studies; and Illinois electricity is managed by two Regional Transmission Organizations (RTOs). As a result, some lessons learned from New York and California, which also have electricity choice markets, may be more relevant to Illinois than issues from Minnesota, which has a vertically-integrated utility structure.

2.2 Data Transparency, Privacy, and Availability

Data privacy, transparency, and accessibility are issues that need to be addressed in the valuation process. While there is a general need for transparency, communication, and collaboration, this must be balanced with protecting customers' privacy, ensuring system safety and reliability, and protecting business sensitive data. Developing hosting capacity analyses provides an example of how other states have dealt with making the necessary data for analyses transparent and accessible while maintaining customer data privacy. A hosting capacity analysis is used to establish a baseline of the maximum amount of DERs that an existing distribution grid (feeder through substation) can safely accommodate without requiring infrastructure upgrades (Homer et al. 2017). Understanding the current infrastructure's capabilities allows stakeholders to make informed decisions when considering generating energy on-site.

At least two stakeholders called for regularly updated hosting capacity analyses (ELPC et al. 2018a; Illinois PIRG 2018a) and noted that both New York and California put forth considerable effort to create reliable hosting capacity analyses early in their valuation processes.

There are typically two types of data needed to analyze hosting capacity—system data and customer consumption data (Trabish 2017). In New York, utilities maintain much of the information necessary for analyzing hosting capacity (NYPSC 2017a). They possess the most extensive understanding of, and access to, the data needed to analyze the locational benefits that DERs contribute to the distribution system. With this type of unilateral access, the need for transparency is important. Hosting capacity maps at the system level and the underlying data aid distributed energy providers in decision making (Trabish 2017).

New York utilities published hosting capacity analyses for solar PV in October 2017. The hosting capacity analyses evaluated distribution circuits greater than or equal to 12 kV and large PV systems at the feeder level (JU NY 2017). The publication of the analyses marks the second of four stages to create reliable hosting capacity analyses. Utilities used the Electric Power Research Institute's DRIVE tool and created their results in the geographic information system-based map environment for accessibility and transparency (JU NY 2017). Steps three and four in the process will expand and improve upon the results in stage two (JU NY 2016).

In order to maintain customer data privacy, New York utilities proposed, and the New York Public Service Commission approved, a “15/15” privacy standard that would keep customer’s identities anonymous when reporting aggregated data sets that are needed for hosting capacity analyses (Homer et al. 2017). This standard would only permit a data set to be shared if it contains at least 15 customers, with no single customer representing more than 15% of the total load. In Docket No. 13-0506, the ICC approved a similar 15/15 rule when it decided on the electric utilities’ release of anonymous individual customer interval usage data in aggregated form (ICC 2014).

Capital investment plans, load forecasts, reliability statistics, and planned reliability and resiliency projects are available in New York’s Public Service Commission filings, and customer energy data are shared with customers and their authorized third parties through utility bills and online platforms. New York utilities recognize that an analysis service that makes data more granular and customized for developers and market participants could become a value-added service. This value-added service would be treated separately from basic data that is accessible at no charge (JU NY 2016).

In addition to a hosting capacity analysis, or integration capacity analysis (ICA) as it is referred to in California, California investor-owned utilities (IOUs) must file a grid needs assessment (GNA) and Distribution Deferral Opportunity Report (DDOR) each year. The objective of the annual GNA is to identify specific deficiencies of the distribution system, identify the cause of the deficiency, and form the basis for annual project lists of needed distribution system upgrades (CPUC 2018a). The DDOR separately addresses planned investments and candidate deferral opportunities (CPUC 2018b).

The California Public Utilities Commission is asking utilities to “share more data, at greater detail and at faster speeds, than utilities have ever had to provide before” (St. John 2015). Specifically, these reports and analyses are asking utilities to provide feeder-level conditions, such as “coincident and non-coincident peaks, capacity levels, outage data, real and reactive power profiles, impedances and transformer thermal and loading histories, and projected investment needs over the following 10 years” (St. John 2015).

California IOUs are not expected to disclose distribution planning data that would breach customer privacy provisions or pose a threat to the security of the electrical system. However, the GNA and DDOR must fulfill specific parameters and both are required to be available in map form and as downloadable datasets. For the GNA, the following must be included relative to specific grid needs (CPUC 2018b):

1. *Substation, circuit, and/or facility ID: identify the location and system granularity of grid need*
2. *Distribution service required: capacity, reactive power, voltage, reliability, resiliency, etc.*
3. *Anticipated season or date by which distribution upgrade must be installed*
4. *Existing facility/equipment rating: MW, kVA, or other*
5. *Forecasted percentage deficiency above the existing facility/equipment rating over five years.*

In the DDOR, planned investments should be classified by:

1. *Project description*
2. *Substation*
3. *Circuit*
4. *Deficiency (MW/kVA, %)*

5. *Project type: Type of equipment to be installed*
6. *Project description: Additional identifying information*
7. *Distribution service required: capacity, reactive power, voltage, reliability, resiliency, etc.*
8. *In-Service Date*
9. *Deferrable by DERs, Y/N?*
10. *Estimated locational net benefits analysis (LNBA)*[1] *range.*

Candidate deferral projects will be identified by:

1. *General geographic region of deferral opportunity, where appropriate, and/or specific location, (e.g., substation, circuit, and/or facility ID)*
2. *In-service date*
3. *Distribution service required*
4. *Expected performance and operational requirements (e.g., season needed, day(s) needed, range of expected exceedances/year, expected duration of exceedances)*
5. *Expected magnitude of service provision (MW/kVA)*
6. *Estimated LNBA range*
7. *Unit cost of traditional mitigation.*

As of February 2018, California IOUs are required to develop a Distribution Resources Planning Data Access Portal that will include the ICA, GNA, DDOR, and LNBA on a circuit map. The underlying data will be exportable in tabular form, and the portal will include an Application Programming Interface to allow users to access data in a functional format from back-end servers in bulk (CPUC 2018b). The utilities' plans for implementing these portals were due to the California Public Utilities Commission in mid-May.

In Minnesota, utilities who want to move forward with the value of solar (VOS) tariff must develop a utility-specific VOS input assumptions table as part of their application—that table is made public. Additionally, a utility-specific VOS output calculation table that breaks out individual components and calculates total levelized value must also be developed and made public (Cory 2014).

The first set of Illinois stakeholder comments generally agreed that data privacy issues must be addressed. As follow-up to the initial comments on data privacy, transparency, and availability, stakeholders were asked "Should there be transparency requirements with respect to information used to compute values?" after the June 28 workshop.

ComEd suggested that the methodology developed and calculations that support locational, temporal, and performance-based factors necessary to determine the components of the valuation be shared, so long as security and privacy concerns are addressed (ComEd 2018b).

Ameren recognized that the rebate "will incentivize customers to act as partners in the efficient development and utilization of the grid" and that "customers and DG [distributed generation] developers

[1] A locational net benefits analysis systematically analyzes the costs and benefits of DERs from a locational perspective. The value of DERs on the distribution system may be associated with a distribution substation, an individual feeder, a section of a feeder, or a combination of these components (Homer et al. 2017). See Section 4.2 for more about the LNBA approach in California.

will need sufficient price and location data to achieve the desired outcome" (Ameren 2018b). They also acknowledged the sensitivity of data from a customer and operations perspective. An approach suggested by Ameren "is to make publicly available only the methodology, types of data that are inputs to the methodology, and the final locational computed values that are the outcome of the analysis" (Ameren 2018b).

IIEC agreed that all elements that affect the rates charged to customers should be publicly available and only information that, if revealed publicly, could pose a security threat to the system should be made available with sufficient protections (IIEC 2018). Joint Solar Parties suggested a default policy be adopted by the Commission that all models used be non-proprietary and fully accessible by all stakeholders, inclusive of underlying data, and that confidentiality concerns be addressed on a case-by-case basis (JSP 2018b).

2.3 Stakeholder Engagement Process

In the comments provided after the March 1, 2018 workshop, a couple of parties suggested establishing stakeholder working group(s) to determine the rebate valuation methodologies and calculations (JSP 2018a; ELPC et al. 2018a), similar to what other states have done. Following the June 28, 2018 workshop, additional comments provided suggestions on the structure and format of stakeholder engagement going forward.

One party suggested Illinois initiate an independent DER working group to discuss the rebate formulation and other important DER policy issues and that the existing Energy Efficiency Stakeholder Advisory Group (EE SAG) be used as a model, where any interested party can participate (ELPC et al. 2018b).

ComEd suggested that the Illinois law language already identified a process for determining the value of distributed generation in Illinois. While a stakeholder process may potentially result in limited, high-level consensus around guiding principles for distributed generation valuation, ComEd argued that any resulting valuation methodology must be vetted through regular ICC legal and regulatory processes. ComEd suggested that additional process suggestions and considerations are more properly reserved for the formal proceeding. However, ComEd also noted that there may be topics outside the scope of the Commission's investigation that would benefit from separate stakeholder engagement workshops (ComEd 2018b).

Ameren is supportive of a designated working group process that is collaborative and promotes consensus to the extent possible. Ameren indicated the utility would be open to any approach proposed by the Commission staff or Commission (Ameren 2018b). It was suggested by Ameren that the process should first focus on value streams directly relatable to the rebate (distribution capacity, losses, and voltage support), whereas remaining value streams will take much longer to determine and may be dependent on the RTOs (Ameren 2018b).

IIEC recommended working groups, limited in size, with representatives of customers, utilities, ICC technical staff, and potential recipients of distributed generation rebates, co-led by representatives of the two major electric utilities (IIEC 2018). Environmental Defense Fund (EDF) is not opposed to a working group process in advance of the formal proceeding, but believes it should not preclude parties from participating in the docketed proceeding, and should not be a substitute for that proceeding (EDF 2018).

Using a working group format could establish some common ground among stakeholders, and therefore minimize the number of contested issues brought before the ICC during formal proceedings (ELPC et al. 2018a). The comments also noted that the working group should have a formal mandate and timeline with a clear set of objectives and deliverables (JSP 2018a, 2018b), and possibly a budget to employ third-party consultants (ELPC 2018), similar to what California, Minnesota, and Oregon have done.

As follow-up to this suggestion, the question of whether the Commission should consider using a consultant to help with developing compensation methodologies and values was specifically asked after the June 28th workshop. Many parties agreed that the use of a consultant could be beneficial.

Clean Power Research was a consultant suggested for consideration (ELPC et al 2018b) and it was emphasized the process would benefit from an experienced, unbiased, and objective third-party consultant (Ameren 2018b). IIEC believed a consultant may be helpful if 1) the workshop process does not yield sufficient results and 2) the ICC technical staff is unable to develop methodologies and values (IIEC 2018).

Working group examples in California include Smart Inverter, LNBA, and ICA. The Smart Inverter working group focuses on the development of advanced inverter functionality as an important strategy to mitigate the impact of high penetrations of DERs (CPUC 2018c). The LNBA and ICA working groups are managed by IOUs and facilitated by More Than Smart (DRPWG 2018), a non-profit whose mission is to pursue "cleaner, more reliable, and more affordable electricity service through the integration of DERs into electricity grids" (More Than Smart 2017). The LNBA and ICA working groups were organized with two primary purposes in mind. In the short term, each group was tasked with supporting the utilities with required demonstration projects, specifically reviewing project plans and monitoring and supporting implementation. In the longer-term, the ICA and LNBA working groups were tasked with helping to refine the ICA and LNBA methodologies, respectively (More than Smart 2016).

For stakeholder engagement in New York, the Joint Utilities of New York[2] had a 15 organization advisory group and nine implementation teams that addressed customer data, DERs and non-wires alternatives suitability, electric vehicle supply equipment, system data, monitoring and control, NYISO/distributed system platform, hosting capacity, load/DERs forecasting, and interconnection. The goals of the stakeholder engagement process were to inform stakeholders of implementation progress, solicit feedback on implementation progress, achieve alignment for moving forward, and incorporate stakeholder input into implementation plans as applicable (Homer et al. 2018).

The stakeholder process conducted in Minnesota was mentioned in stakeholder comments as a potential model for Illinois (ELPC et al. 2018a). The Minnesota Department of Commerce selected a third-party consulting firm, Clean Power Research (CPR), to support the process of developing a valuation methodology. Stakeholders participated in four public workshops facilitated by the Department of Commerce and provided comments through workshop panels, workshop Q&A sessions, and written comments (CPR 2014). Stakeholders included Minnesota utilities, local and national solar and environmental organizations, local solar manufacturers and installers, and private parties (CPR 2014).

2.4 Incremental Approach

New York and California had an evolutionary approach to their valuation process; the Joint Solar Parties suggested an incremental process may be appropriate for Illinois as well. Joint Solar Parties advised that a "first-generation" valuation model that can be deployed by the threshold date may be necessary (JSP 2018a). An incremental or evolutionary approach is recommended by Joint Solar Parties because

[2] The Joint Utilities are comprised of Central Hudson Gas and Electric Corporation, Consolidated Edison Company of New York, Inc. ("Con Edison"), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation doing business as National Grid ("National Grid"), Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation.

DER technologies themselves and utilities' ability to integrate DERs into grid operations and planning are also evolving (JSP 2018b). Joint Solar Parties suggests the process employ a near-term track to establish placeholder values and a long-term track that focuses on developing a granular methodology and then refining it (JSP 2018b). Details on this suggested approach is provided in Section 4.2

Other stakeholders also noted a gradual implementation with interim steps could help prevent market uncertainty and send clear price signals to all parties (ELPC et al. 2018a; ComEd 2018b; JSP 2018a). It was also suggested that the valuation model be based on an objective cost-benefit analysis with the flexibility to adapt to unforeseen circumstances (ComEd 2018a, 2018b; IIEC 2018). Keeping Illinois' particular market and policy goals in perspective throughout the process will be essential. Implementation timetables should be realistic, with time to incorporate lessons learned throughout the process and from experiences in other jurisdictions moving along similar paths (ComEd 2018b).

2.5 Alternative and Separate Compensation Mechanisms

All parties acknowledged that DERs can provide additional benefits beyond those provided to the distribution network. After the March 1st workshop, many stakeholders suggested that there are alternative or existing compensation mechanisms for the distributed generation values beyond the distribution system.

ComEd suggested renewable portfolio standards, wholesale energy and capacity markets, ancillary service markets, and tax incentives as potential alternative compensation mechanisms to capture the additional benefits (ComEd 2018a), and the Environmental Law and Policy Center highlighted the need for further evolution of DER policy in order for this to occur (ELPC et al. 2018a). One party suggested that ancillary services benefits that distributed generation provides should not be compensated for in a rebate, if they are already being compensated for in distribution rates or through markets or other existing or future mechanisms (ELPC et al. 2018b).

Other compensation mechanisms that already exist include the net metering energy credit and the purchase of renewable energy certificates (RECs) through the Adjustable Block Program, Illinois Solar for All Program, Community Renewable Generation Program, and other competitive REC procurement programs.

The REC pricing models for the Adjustable Block Program, Illinois Solar for All Program, and Community Renewable Generation Program, as established by the IPA, will establish REC prices as the difference between a system's expected, calculated cost of energy and the system's expected revenue from the net metering energy credit. REC prices in these programs will be adjusted for factors such as system size, the additional costs of small subscribers to community solar, and the additional costs to low-income consumers; these potentially will account for any changes to net metering compensation, the distributed generation rebate, and federal tax credits. (IPA 2017). As a result, the REC value is intended to bridge the gap between cost of energy and net metering revenue to ensure the distributed generation systems will be cost effective, thus encouraging customer adoption.

An alternate perspective, from Joint Solar Parties, considered the REC to represent the renewable portfolio standard (RPS) compliance value, but not all environmental or societal benefits. ComEd disagreed and suggested that purchasing RECs for RPS compliance is essentially compensating distributed generation for its environmental attributes. Either way, RECs are one example of a mechanism to compensate distributed generation beyond its direct impact to the distribution system.

After the June 28, 2018 workshop, the question of "which value streams should be separately compensated pursuant to Section 16-107.6?" was specifically asked. Many parties agreed that the determination of the value of distributed generation to the distribution system cannot be done in isolation (ComEd 2018b; ELPC et al. 2018b). A holistic perspective was recommended that considers all of the mechanisms that compensate distributed generation, to ensure the overall compensation for distributed generation is sufficient but not excessive and to consider any potential policy changes to any of the compensation mechanisms (ComEd 2018b, EDF 2018).

ELPC and partners suggested that at the present time, it is not precisely clear which value streams should be compensated through a distributed generation rebate and which could or should be compensated through other policy mechanisms. Subsequently, the initial investigation should be broad and consider all values (ELPC et al. 2018b). As an example, it was pointed out that there is a potential for FERC to establish market participation rules for compensating additional values of DER through wholesale markets and as a result, the Commission may establish interim values as placeholders for benefits that cannot be precisely characterized or compensated through other mechanisms (ELPC et al. 2018b).

During the investigation into the rebate and as the rebate is developed, it is important that the process be designed to 1) identify the complete set of value components of distributed generation to ensure they are properly compensated either through the rebate or elsewhere (ELPC et al. 2018b; EDF 2018; JSP 2018b), 2) avoid double counting (e.g., compensating the same value components in both the wholesale markets and in customer rates at the distribution level), and 3) creating unfair subsidies among customers (ComEd 2018b).

Ameren and IIEC pointed out that operating reserves and frequency regulation would likely flow from the applicable RTO available markets (Ameren 2018b; IIEC 2018) and compensation for energy benefits should be calculated in accordance with existing law or tariffs (Ameren 2018b). Eventually, Ameren pointed out, it may be appropriate to add a locational factor to the energy supply value based on the metered location on the distribution system, in which case, more detailed system and cost data would be needed (Ameren 2018).

Alternately, Joint Solar Parties argued that the transmission system benefits should be included in the rebate (JSP 2018b). Joint Solar Parties suggested that the transmission capacity deferral value can be an important part of DER valuation studies, noting that in California, billions of dollars of transmission upgrades were avoided due to rooftop solar along with energy efficiency, reflected in reduced local area load forecasts (JSP 2018b).

EDF emphasized that in their perspective, completeness has two aspects. First, methods for identifying the full suite of distribution values must be established, and second, generally recognized value streams currently excluded from existing mechanisms must be remedied. EDF recommended that the rebate calculation be used to incorporate what they see as previously excluded values (EDF 2018).

2.6 Grading Circuits

In the June 28th workshop, and in subsequent comments, grading circuits for the purpose of establishing distributed generation capacity value price points was discussed. Some parties agreed grading circuits would be a useful way to convey the relative value and need of DERs (ELPC et al. 2018, Ameren 2018b). Hawaii can be used as an example, where circuits are color coded based on the percent available on the circuit relative to hosting capacity (ELPC et al. 2018). Ameren noted that the use of circuit-level values may initially be practical with the creation of three to five rebate value categories to use (Ameren 2018b).

2.7 Standardization and Capital Investment Plans

Another question prompt given to stakeholders after the June 28th workshop was "should there be standardization with respect to information used to compute values?" Some parties agreed there should be standardization and transparency in models and methodologies (ELPC et al. 2018; JSP 2018b), particularly with respect to projections of load growth and distributed generation growth, but Ameren also suggested there should be sufficient flexibility in the overall methodology (Ameren 2018b).

The question of "should utilities be required to develop and share capital and investment plans" was also put forward. One stakeholder group agreed that developing and sharing capital investment plans should be a high priority for Illinois because robust distribution system planning is needed to accurately characterize the value of DER over the long-term (ELPC et al. 2018). The Integrated Distribution Planning (IDP) process proposed in a white paper by GridLab as part of Ohio's PowerForward proceeding was suggested as a potential example (ELPC et al. 2018). Ameren, in their second round of informal comments, resisted the notion that utilities be required to develop and share capital investment plans beyond what is already required by existing regulation and practices. Ameren was also opposed to making public information about candidate deferral projects, deferred distribution investment, or marginal cost of service studies (Ameren 2018b).

3.0 Valuation Components

As presented in PNNL's *Distributed Generation Valuation and Compensation White Paper* (Orrell et al. 2018), the first step in typical value of distributed generation calculations is to survey the different value components, and their associated costs and benefits, that could be used as the valuation building blocks. States include different elements in their calculations based on state-specific policy goals or legislation.

New York's value of distributed energy resources (VDER) tariff components are presented in Table 1 as an example of a comprehensive list of valuation components (beyond just value to the distribution system) with details on how the calculations are accomplished. New York's demand reduction value (DRV) and locational system relief value (LSRV) are unique when compared to the Minnesota VOS tariff, and represent one aspect of direct value to the distribution system.

Table 1. New York's VDER Components (NYPSC 2017b)

Component	Calculation Based On
Energy value	Day-ahead hourly locational based marginal price grossed up for losses (eventually moving to subzonal prices)
Capacity value – market value	Monthly NY Independent System Operator auction price
Capacity value – out of market value	The difference between the market value and the total generating capacity payments made to value stack customers
Environmental value – market value	Higher of Tier 1 renewable energy certificate (REC) price per kWh, or social cost of carbon per kWh less Regional Greenhouse Gas Initiative (RGGI); customers who want to retain RECs will not receive compensation
Environmental value – out of market value	Difference between compensation and market will be recovered from customers within the same service class as the customers receiving benefits from the DER
Demand reduction value	Compensation based on marginal cost of service studies and eligible DER performance during 10 highest usage hours at $ per kW-year value
Locational system relief value	Compensation based on marginal cost of service studies and static rate per kW-year value applied to net injected kW
Market transition credit	Static rate per kWh applied to net injected kWh; steps down by tranche

An NREL report, *Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electricity Utility System*, classifies the sources of distributed solar benefits and costs in a more traditional way that includes the following (Denholm et al. 2014):

- Energy
- Environmental
- Transmission and distribution (T&D) losses
- Generation capacity
- T&D capacity

- Ancillary services
- Other factors.

Figure 1 provides an illustrative example of valuation components. Specifically, Figure 1 shows the varying impacts different renewable distributed generation value components have on the average monthly value of energy ($/MWh) from an avoided cost perspective in California. These values were computed from an E3-developed avoided cost calculator that all the large IOUs in California are obligated to use. Figure 1 shows that, in California, potentially avoided distribution costs from distributed generation are greater in the summer than in other months. The figure also shows that the value distributed generation provides to the distribution system is only one, relatively small, part of the overall value proposition of distributed generation to the electric system.

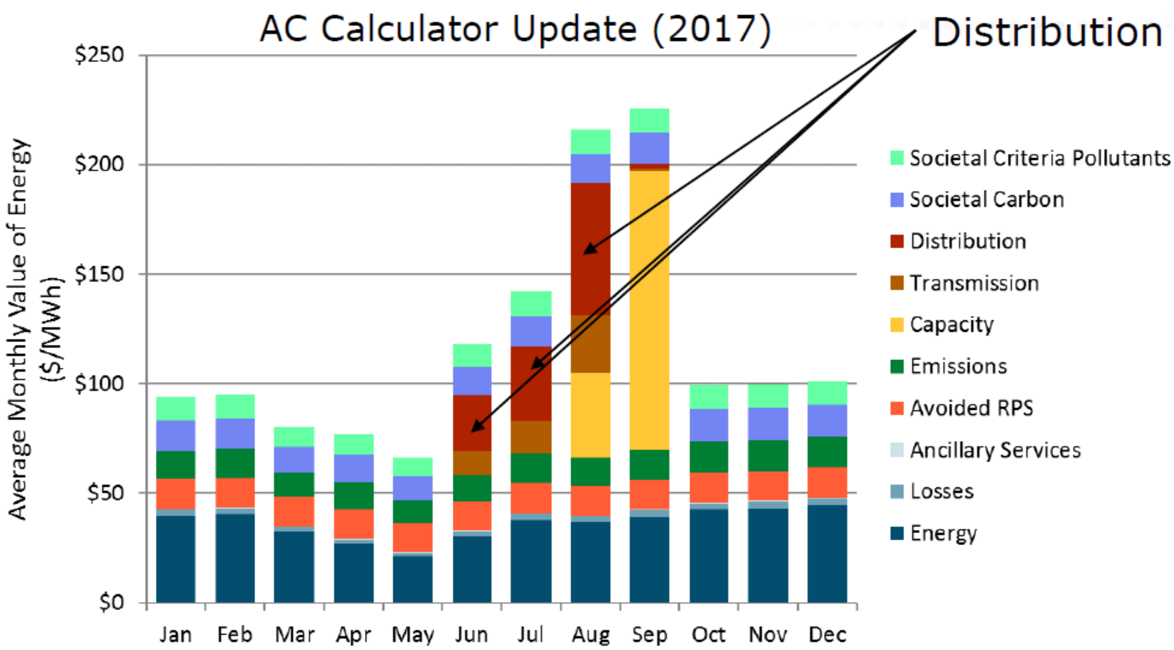

Figure 1. Average Monthly Value of Energy in California (E3 2017)

3.1 Distribution System Value Components

With respect to costs and benefits specific to the distribution grid, Table 2 lays out the common value elements identified for Illinois in the stakeholder comments resulting from the initial white paper and the workshop on distributed generation valuation and compensation. In general terms, these are presented in relative order of value from left to right.

Table 2. Distribution System Value Elements

	Value Element				
Commentator	**Avoided Distribution Capacity Costs**	**Reduction in Distribution Losses**	**Distribution Voltage Support**	**Reliability and Resiliency**	**Standby Capacity**
Ameren Illinois	X	X	X		
ComEd	X		X	X	X
Joint Solar Parties	X		X	X	

Each of these distribution system value elements are described in more detail below. Distributed generation value elements other than distribution system impacts are not addressed in detail in this report. However, if detailed value calculations for other categories of impacts are desired going forward, Denholm et al. 2014 offers a detailed summary of approaches ranging from simple to complex for calculating benefits and costs associated with energy, environment, transmission losses, generation capacity, transmission capacity, and ancillary services resulting from distributed PV systems (Denholm et al. 2014). California, New York, and Minnesota also provide good examples of calculations for value elements beyond impacts to the distribution system.

3.1.1 Distribution Capacity Value

The distribution capacity value resulting from the addition of distributed generation represents the net change in distribution infrastructure requirements (RMI 2013). The presence of distributed generation may increase or decrease distribution system investments needed to meet system needs and keep the system running safely and reliably (Denholm et al. 2014), or it may have no impact at all (IIEC 2018). In certain instances, distributed generation can help to meet rising demand locally, relieving capacity constraints and avoiding upgrades. In other circumstances, added costs are incurred when additional distribution investments are necessary to upgrade wires, transformers, voltage-regulating devices, control systems, and/or protection equipment (RMI 2013; Denholm et al. 2014). There can be significant variations in the value of distributed generation from one location to another.

The value of deferring or avoiding distribution investments is a function of "load growth, distributed generation configuration and energy production, peak coincidence, and effective capacity" (RMI 2013). Calculating distribution system capacity value requires comparing expected capital investments or expansion costs <u>with</u> distributed generation and <u>without</u> distributed generation. Power flow analysis is typically the basis of this type of analysis.

In other value of distributed generation related dockets around the country, there is disagreement as to whether system-wide average avoided distribution attributable costs should be used or whether location-specific investments should be considered. In other proceedings, there has also been disagreement about whether only growth-related distribution investments should be considered, or all potentially deferrable distribution system investments (OPUC 2017).

To assess locational aspects of distributed capacity deferral, granular planning information is needed. A first step in this regard is for utilities to compile capital expenditure plans in each geographic area and then assess what may be deferred or avoided, or needs to be enhanced, due to distributed generation in those areas.

In the absence of specific avoidable projects and values, marginal cost of service (MCOS) studies can provide a basis for calculating avoided or added distribution capacity value. MCOS studies quantify the marginal cost of electricity service by calculating the additional costs associated with changes in kilowatt-hours of energy, kilowatts of demand, and number of customers. Using MCOS studies, the value of an avoided or added distribution asset can be estimated to be the cost of sub-transmission costs plus substation costs, in dollars per kW-year. However, IIEC cautions that MCOS studies do not provide a reasonable proxy unless the need for capacity expansion, and thus avoidable costs, is known with relative certainty and if that need is imminent (IIEC 2018).

NREL summarizes a number of methods that can be used to approximate the capacity value of distributed generation (Denholm et al. 2014). Six different potential methods are summarized in Table 3 in increasing order of detail and complexity.

Table 3. Methods for Estimating Distributed Generation Capacity Value (Denholm et al. 2014)

Name	Description	Tools Required
1. PV capacity limited to current hosting capacity	Assumes distributed-generation PV does not impact distribution capacity investments at small penetrations, consistent with current hosting capacity analyses that require no changes to the existing grid	None
2. Average deferred investment for peak reduction	Estimates amount of capital investment deferred by distributed-generation PV reduction of peak load based on average distribution investment costs[1]	Spreadsheet
3. Marginal analysis based on curve fits	Estimates capital value and costs based on non-linear curve fits, requires results from one of the more complex approaches below	Current: Data not available Future: Spreadsheet
4. Least-cost adaptation for higher PV penetration	Compares a fixed set of design options for each feeder and PV scenario	Distribution power flow model with prescribed options
5. Deferred expansion value	Estimates value based on the ability of distributed-generation PV to reduce net load growth and defer upgrade investments	Distribution power flow models combined with growth projections and economic analysis
6. Automated distribution scenario planning (ADSP)	Optimizes distribution expansion using detailed power flow and reliability models as sub-models to compute operations costs	Current: No tools for U.S> system. Only utility/system-specific tools and academic research publications on optimization of small-scale distribution systems. In practice, distribution planning uses manual/engineering analysis Future: Run ADSP 2+ times with and without solar

The most basic way to consider distribution system capacity value (Method 1 in Table 3 above) is to assume that at very low levels of distributed generation, where total distributed generation is less than the hosting capacity of a circuit, there is minimal impact (positive or negative) on distribution capacity investments. This is consistent with the definition of hosting capacity as the amount of distributed generation that can be integrated into the system without changes to capacity or operations. In these cases, it can reasonably be assumed that the distribution capacity value is zero. It is important to note that this approach only applies at very low penetration rates of distributed generation and it does not capture potential costs or benefits from peak reduction (Denholm et al. 2014).

The second method described in Table 3 approximates the value of deferred distribution system investments for reducing peak demand. A key assumption is that a fraction of distribution capital investments is used to address load growth. Costs reported to Federal Energy Regulatory Commission (FERC) on Form 1 (accounts 360-368) cover categories of costs that each include a fraction used for load

[1] Estimating capital investment deferral can be accomplished by determining the average capacity factor of DER during peak net load hours and/or by calculating the effective load carrying capacity of the DER through probabilistic reliability modeling and then applying to that reduction the average distribution investment costs.

growth. Summing load growth costs in each FERC cost category allows for the calculation of average capital costs per kilowatt. From here, the peak reduction from distributed generation can be translated into a capacity value (Denholm et al. 2014). The Minnesota VOS example in Section 4.5 is an example of this method for estimating distribution capacity value. There are various methods for calculating the peak reduction attributable to distributed generation, including capacity factor approximation using net load, capacity factor approximation using loss of load probability, effective load-carrying capacity (ELCC) approximation, and full ELCC (Denholm et al. 2014).

Methods 3 through 5 in Table 3 increase in level of detail and complexity, and in each case the type of analysis is novel and/or still in the research and development phase. Method 3 entails conducting in depth studies of a large representative set of distribution feeders (using one of Methods 4–6 described below) and then creating curve fits that estimate the marginal benefits and costs based on feeder and PV system characteristics. This type of analysis has been conducted in research settings, but to the best of our knowledge, not yet in commercial applications. Method 4 entails looking at the least-cost ways to provide mitigation when distributed generation interconnection exceeds feeder hosting capacity. Rather than upgrading transformers or conductors or adding voltage regulators, the least-cost adaptation option considers enabling or requiring smart inverter functionality in addition to or in lieu of other mitigations for each feeder and PV scenario. Method 5 entails computing the feeder-specific value of deferred distribution investments when distributed generation offsets load growth. The difference between this and Method 2 is that rather than using aggregate data, this is a bottom up approach where load and distributed generation growth for all feeders or a representative sample are calculated along with the corresponding avoided costs (Denholm et al. 2014). Method 5 is similar to California's LNBA approach and New York's LSRV approach.

Finally, Method 6 from Table 3 proposes using computer models to directly calculate multi-year capital investments needed to accommodate growth and other load changes, such as an increase in electric vehicles. The net present value of a no distributed generation baseline would be compared to scenarios with distributed generation to estimate the distribution capacity value. This analysis includes the use of detailed power flow and reliability models to compute operations costs. There are presently no comprehensive and automated tools available to conduct this type of analysis for systems in the United States (Denholm et al. 2014).

Until such time that detailed and automated models to automatically calculate distribution capacity value of distributed generation become available, it is recommended that a reasonable approximation method be used to estimate distribution capacity value. Examples from other states are provided in Section 4.0.

Important items to consider when evaluating potential distribution capacity deferrals include the following (Lew 2018):

- Is there a need for distribution system upgrades or new capacity? How much excess capacity is available now and over the planning horizon?
- Does the output from distributed generation match the stressed hours and seasons of the capacity need?
- Does the location of distributed generation match where the need exists for deferred capacity?
- Can the distributed generation consistently and reliably provide power when needed?
- Will distributed generation be available through the deferral period?
- Can the utility monitor and control the distributed generation to meet distribution system needs?

In their comments, IIEC noted that savings to secondary distribution circuits will not significantly benefit customers taking service at primary voltage or transmission voltage levels. IIEC points out that eventually, when rate design is considered, the Commission should recognize the varying levels of assumed benefits among customer classes (IIEC 2018). IIEC also pointed out that "while benefits of distribution capacity value due to expanded distribution generation are theoretically possible, they are highly uncertain and, in certain cases, may be negative" (IIEC 2018).

In their comments, EDF pointed out that FEJA notes a number of considerations that values should reflect, including present and future grid needs. As an example of future grid needs, EDF pointed out distributed generation could be used to, among other things, offset electric vehicle charging loads and future infrastructure investments. EDF suggested these kinds of capacity needs should be considered in determination of capacity benefits of distributed generation for the purpose of the rebate (EDF 2018).

3.1.2 Reduction in Losses

Because distributed generation is typically located near loads, it can result in avoided distribution losses. In some studies, such as the Minnesota VOS study, losses are included in avoided capacity cost calculations. At very high penetrations, however, where there is reverse power flow, distributed generation can result in increased losses. There are different methods for computing loss rates in distributed generation studies. The most basic approach is to assume that distributed generation avoids an average distribution loss rate. Increasing in complexity, the average loss rate can be modified with a non-linear curve fit representing marginal loss rate as a function of time. Increasing in complexity further, the marginal loss rates at various locations in the system can be computed using curve fits and measured data. Finally, loss rates can be calculated using power flow models and a detailed time series analysis (Denholm et al. 2014).

PNNL conducted a study for Duke Energy to simulate the effects of high-PV penetration rates and to initiate the process of quantifying the generation, transmission, and distribution impacts. In the model simulations, both real and reactive losses on the distribution feeders decreased during higher load periods, typically in the summer. During lower load periods, both real and reactive losses tended to increase. On average, feeders show a reduction in losses due to the addition of solar distributed generation, particularly in the summer season. The study concluded that any net benefit is dependent on feeder topology, PV penetration level, and interconnection point, and should be evaluated on a case-by-case basis before assigning associated costs or benefits (Lu et al. 2014).

3.1.3 Voltage Support, Operating Reserves, and Other Ancillary Services

Ancillary services, also referred to as grid support services, are those services required to enable the grid to operate reliably, and typically include operating reserves, reactive supply and voltage control, frequency regulation, energy imbalance, and scheduling (RMI 2013). The two ancillary services that are most commonly associated with distributed generation are voltage control and operating reserves.

Voltage levels must be kept within acceptable values at all locations in the distribution system. Without advanced inverters, large distributed generation power injections can contribute to overvoltage conditions that may require new voltage-regulating equipment or controllers. Variable distributed generation power production can also lead to increased wear and tear on switches and voltage-control equipment. However, distributed generation with smart inverters can actively support voltage regulation on the distribution system and mitigate distributed generation-produced voltage issues, reducing the mechanical wear on transformer tap changers and capacitor switches and conceivably replacing traditional voltage-control equipment (Denholm et al. 2014). When reactive power is provided by smart inverters, it reduces the amount of reactive power that is required from large central generators, allowing them to operate at more efficient (real) power output levels, reducing transmission losses and increasing the (real) power capacity of transmission lines (Denholm et al. 2014).

Although detailed studies are necessary for determining the specifics of distributed generation's impact on ancillary services as accurately as possible, a hosting capacity analysis can serve as a good starting point. A hosting capacity analysis indicates the maximum amount of distributed generation that specific locations on the distribution grid can safely accommodate without requiring infrastructure upgrades that may be needed to avoid voltage violations, power quality issues, protection problems, or exceeding thermal limits (Homer et al. 2017). At distributed generation penetrations below a circuit's hosting capacity, depending on how the hosting capacity is calculated, it can reasonably be assumed there are no significant voltage or reliability impacts.[2]

In order to truly calculate the voltage impacts of distributed generation to the distribution system, detailed time series power flow analysis is needed with and without distributed generation. From the two analyses, differences in equipment requirements, system operating conditions, system operating costs, and tap changes can be noted and attempts made at assigning cost or savings to distributed generation impacts. The difficulty lies in estimating the non-capital costs or savings, such as the increase or decrease in remedial actions required for addressing voltage violations, the increased or decreased maintenance required due to difference in number of tap changes, and impacts of customer complaints, potentially leading to regulatory consequences. Many of the voltage impacts, positive and negative, of distributed generation occur in ways that are difficult to assign a monetary value and the presence of a smart inverter changes those impacts.

Operating reserves address short-term variability and plant outages. Although they are traditionally required at the transmission level and provided by traditional generators, some types of operating reserves can also be provided by distributed resources.[3] Operating reserves are often estimated by assessing the reliable capacity that can be counted on from distributed generation when needed over the year. The higher the reliable capacity of distributed generation that is available when needed, the less operating reserves are necessary. Where wholesale markets exist, the value of ancillary services can be determined based on the market prices. While variability and uncertainty from large amounts of distributed generation may introduce operations forecast error and increase the need for certain types of reserves, distributed generation may also reduce the load that must be served by central generation and reduce the needed reserves (RMI 2013).

Denholm et al. (2014) proposed three different approaches to estimating the impact of distributed generation solar PV on ancillary services value (see Table 4). The first approach is to assume no impact due to the penetration of PV being too small to have a quantifiable impact and/or due to the fact that PV's impact on ancillary services is poorly understood. Table 4 also lists a simple cost-based method and a detailed cost-based method for estimating impacts of distributed generation on ancillary services value. The simple method estimates changes in ancillary service requirements (such as reduced spinning reserve requirement as a result of reduction in net load) and applies cost estimates or market prices for corresponding services. The detailed method includes running simulations with increasing distributed generation and calculating the impacts on reserve requirements and ancillary services provided by the distributed generation.

[2] If hosting capacity analysis uses an either peak/off peak static snapshot or a one hour time step to assess potential voltage problems, it could miss some of the transient and/or power quality issues that might be present.
[3] Specific stakeholder comments on valuing operating reserves and other ancillary services are provided in Section 2.5.

Table 4. Approaches for Estimating Impact of Distributed PV on Ancillary Services (Denholm et al. 2014)

Name	Description	Tools Required
1. Assumes no impact	Assumes PV penetration is too small to have a quantifiable impact	None
2. Simple cost-based methods	Estimates change in ancillary service requirements and applies cost estimates or market prices for corresponding services	None
3. Detailed cost-benefit analysis	Performs system simulations with added solar and calculates the impact of added reserves requirements; considers the impact of distributed-generation PV proving ancillary services	Multiple tools for transmission- and distribution-level simulations, possibly including PCM, AC power flow, and distribution power flow tools

3.1.4 Reliability and Resiliency

In the Oregon Resource Value of Solar (RVOS) docket, security, reliability, and resiliency were originally included as a separate category in the RVOS calculation. However, following parties' comments, the Commission decided to fold reliability, security, and resiliency into a new category, simply named grid services. The consulting firm Energy and Environmental Economics, Inc. (E3), who provided comments in the Oregon RVOS docket, said that solar generators "with advanced and uncommon infrastructure such as microgrids are capable of islanding during an outage event, but this benefit accrues to the owner and not to the general utility ratepayers" (OPUC 2017). E3 recommended that security and reliability benefits should not be valued in Oregon's RVOS calculation because "reserve" benefits are already accounted for as part of ancillary services. Likewise, Denholm et al. (2014) addressed reliability in terms of distribution and transmission capacity investments, but not as a separate value category.

In their comments, IIEC suggested that expanded distributed generation has the potential to improve reliability and resiliency of the distribution system, but uncoordinated penetrations of distributed generation can also reduce the reliability and resiliency of the distributions system through voltage fluctuations or otherwise (IIEC 2018).

4.0 Example Approaches

This section provides specific calculation approach recommendations and examples that are applicable to Illinois. In their second round of comments, Joint Solar Parties pointed out that a number of states have tried and ultimately failed to resolve the interconnected and complicated set of issues associated with DER compensation methods to provide value-based signals (JSP 2018b). In each case, the state had flexibility to institute an alternative interim method. ComEd also noted that no state has successfully implemented location-specific distribution system value compensation at any point more granular than the substation level (ComEd 2018b).

4.1 Ameren Illinois Calculation Suggestions

Ameren suggested that the valuation of distributed generation to the distribution system should take into account the following (Ameren 2018a; Ameren 2018b):

- *The specific location on the distribution system, down to the transformer if possible*
- *The times of day, week, or year it is available and what kind of weather*
- *The capabilities the distributed generation can provide (real power, reactive power, or both)*
- *Other distributed generation operating characteristics (ramp rates, voltage support, dispatch ability, etc.).*

To calculate the value of distributed generation to the distribution system, Ameren suggested the following process (Ameren 2018a; Ameren 2018b):

1. *System capacity studies starting at the smallest distribution system asset level (distribution line transformer) then aggregate results upstream towards the bulk supply sub-transmission power transformer. These studies could compare baseline system capacity (current state of the distribution system) against cases of distributed generation penetration at specific locations on the distribution system.*
2. *A system line loss study comparing baseline (current state of the distribution system) against cases with distributed generation penetration at specific locations of the distribution system.*
3. *System reliability studies including voltage, protection, and phase balance comparing baseline (current state of the distribution system) against cases with distributed generation penetration at specific locations of the distribution system.*
4. *Using the above results, an economic analysis could be used to determine the value of distributed generation at the specified location on the distribution system.*

In steps 1 through 3, studies will use hourly historic load data, hourly load forecast data, DER generation profiles, and current company planning and reliability criteria at each transformer node for a given feeder. Costs will be compared between current system snapshots and snapshots of system with upgrades and DER connected at given locations (Ameren 2018b).

This process requires accurate distribution system models down to the distribution line transformer level for conducting system capacity, line loss, and reliability studies; identifying the specific distributed generation scenarios to model; and obtaining cost information. The differences between this proposed approach and the Minnesota example described in Section 4.5 include that Minnesota's process only applies to solar, whereas Ameren's is intended to be more widely applied to different types of DERs;

Minnesota's framework is not primarily location/geographic specific,[1] whereas Ameren intends to characterize value at specific locations on the distribution system; and Minnesota does not consider Volt/Var support to the distribution system, whereas Ameren's will (Ameren 2018b).

4.2 Joint Solar Parties Suggested Approach

Joint Solar Parties suggested the valuation process employ a near-term track to establish placeholder values and a long-term track to focus on developing a granular methodology and then refining it. Joint Solar Parties noted that Section 16-107.6 is unambiguous in the fact that the incentive must be an upfront payment and that it must address present and future grid needs as understood at the time of the rebate. Joint Solar Parties suggested that since a DER would be capable of addressing future grid needs over the course of its useful life, the rebate value must reflect the value over the useful life of a DER (JSP 2018b).

In an incremental approach, Joint Solar Parties suggested that there is no rational basis for assuming the magnitude of a given DER value stream is zero, either because of data insufficiencies or because the value was difficult to measure (JSP 2018b). Joint Solar Parties referred to numerous DER value studies across the country that have identified non-zero values for various components (JSP 2018b).

Joint Solar Parties noted that based on experience in other states, the time necessary to develop even a first-generation methodology could be measured in years rather than months (JSP 2018b). Joint Solar Parties recommended the following iterative approach in its second round of comments.

- Recognize and respond to differences between mass market customers compared to community solar or demand rate customers.
- Illinois' near-term approach can infer DER value as a simple percentage of applicable system costs and incorporate a market transition mechanism similar to the market transition credit in New York as a way to bridge the gap and ensure a smooth transition between current net metering and a more robust valuation regime. (See Section 4.4 for more on the use of the market transition credit in New York.) In their second round of comments, Joint Solar Parties explained how this near-term valuation approach can be made consistent with the requirements of the rebate to address geographic, time-based, and performance-based features of DERs (see page 11 of JSP 2018b).
- Valuation efforts should be prioritized based on a combination of the likely magnitude of different value streams, ease of development, and Illinois' statutory requirements. Joint Solar Parties recommended the proceeding start with a focus on the following (JSP 2018b):
  - Determine market segment differentiation
  - Develop and vet marginal cost studies or a substitute; may start with establishing parameters for future marginal cost studies and how they will be used to develop DER values and/or devising a substitute method and the parameters surrounding its use
  - Focus on system level
  - Focus on distribution and transmission level capacity deferral value
  - Establish smart inverter valuation mechanism
  - Determine how energy storage is valued

[1] The Minnesota methodology is a system-wide approach. It could be adapted to reflect a location-specific approach, but minimal guidance on how to apply it locally is provided.

– Define additional value streams, including reduced O&M, extended equipment lifetimes, reduced sizing for equipment replacement, and enhanced awareness and grid visibility.

4.3 California Locational Net Benefits Analysis

The three large IOUs in California (Pacific Gas & Electric, San Diego Gas & Electric, and Southern California Edison) jointly engaged the consulting firm E3 to develop a technology-agnostic Excel tool for estimating location-specific avoided costs of DER for LNBA demonstration projects. The LNBA tool has two major parts—a project deferral benefit module, which calculates the values of deferring a specific capital project, and a system-level avoided cost module, which estimates the system-level avoided costs given a user-defined DER solution. The summation of the quantitative results provided by the two modules provides an estimate of the total achievable avoidable cost for a given DER solution at a specific location. Demonstration projects are underway with each of the large IOUs to test tools for locational benefits analysis.

As part of the LNBA work in California, utilities are developing public tools and heat maps that will be made available online to enable customers and developers to identify optimal locations for installing DERs. Results from LNBA will also be used to prioritize candidate distribution deferral opportunities. In June 2017, the California Public Utility Commission recommended refinements to the LNBA analysis to include valuing location-specific grid services provided by smart inverters, evaluating the effect on avoided cost of DER working in concert within the same substation footprint, and increasing granularity in avoided cost values (CPUC 2017).

Strategically targeted distributed PV can relieve distribution capacity constraints. In a series of benefit cost studies, dispersed deployment of PV has been found to provide less benefit than targeted deployment. Therefore, in order to access any significant capacity deferral benefit, proactive distribution planning for DERs is required (RMI 2013).

4.4 New York – Value of DER Tariff Calculation

In New York's value of DER proceeding, the New York Public Service Commission ordered the implementation of a successor to Net Energy Metering tariffs that will provide incentives reflecting the locational value of DER. New York's value of DER tariffs, also called value stack tariffs, are being designed to replace net metering for larger-scale community solar PV projects (up to 5 MW) in the short term, and will eventually be applied to all DERs across the grid. In addition to the other value components listed in Table 1 (i.e., energy value, environmental value, and capacity value), a DRV and LSRV are being developed as a means to identify, quantify, and compensate for value specific to the distribution system.

To calculate LSRVs and DRVs, New York utilities used a three step process of first identifying LSRV areas, then setting a cap to limit the amount of DER capacity that may receive LSRV compensation, and finally calculating LSRV and DRV rates. Utilities were required to look at their systems and identify thresholds beyond which areas would be identified as LSRV areas or zones and community solar projects in those areas that would receive additional compensation, up to a cap.[2] Additional compensation would

[2] For example, Con Edison's LSRV threshold was established as those areas in the year 2021 where projected energy use reaches or exceeds 98% of current capability in sub-transmission, 98% of current capability in area stations or 90% of current capability in distribution network areas. According to this threshold, 19% of Con Edison's service territory qualify as LSRV zones. National Grid's threshold was established by scaling loads on all

then be provided to DER owners in these constrained areas up until the threshold conditions were no longer met.

Compensation amounts for the DRV and LSRV are based on each utility's own MCOS studies. As such, value calculations can be significantly different from one utility to the next. Goals for phase 2 of the value of DER proceeding include improving the MCOS studies and LSRV methodology and standardizing them to the extent possible, while recognizing that "symmetry across all utilities in all aspects of the distribution planning methods is not realistic or necessarily desirable" (NY PSC 2017b). More details on the DRV and LSRV calculations in New York are contained in Appendix A.

In New York, a market transition credit is also offered as part of the transition from net metering to a value stack tariff for community-level distributed generation projects. The intent of the market transition credit is to avoid market disturbance in the transition away from net energy metering. The market transition credit is calculated by the utility, and applies for a full 25 years. The first tranche of value stack customers received a market transition credit that resulted in total compensation equal to previously applied full net energy metering compensation. In other words, the first tranche market transition credit was essentially equal to the difference between the base retail rate and the estimated value stack rate. The tranche 2 and tranche 3 market transition credits provided for total compensation of 95% and 90% of net energy metering compensation, respectively. Each utility has a capacity cap for each tranche of the market transition credit (NYPSC 2017a).

In their comments, Joint Solar Parties suggested that some elements of the New York approach could be applied to Illinois (e.g., using an iterative approach to refine a methodology through a working group process with attention to gradualism and market impacts, or the use of MCOS studies), but some of shortcomings of the New York process, in their opinion, are that the assessment only incorporated avoided distribution capacity values and not value streams that can be provided by smart inverters as well as the lack of transparency and consistency between how marginal costs were calculated by different utilities (JSP 2018b).

4.5 Minnesota Example Calculation

Although Minnesota has a vertically-integrated electricity supply market, its VOS tariff calculations provide an example of calculating distribution system values associated with distributed generation that can be applicable to Illinois.

Minnesota allows utilities to take a system-wide or location-specific approach when calculating the avoided distribution capacity costs. A location-specific approach would allow utilities to provide more compensation to systems located in high-needs areas. If a utility decides to use the location-specific approach, it must follow the guidance provided within the system-wide calculation and use location-specific technical and cost data (CPR 2014). Figure 2 contains a flowchart created by PNNL that illustrates the distribution capacity value calculation. The detailed breakdown of how to calculate avoided distribution capacity costs per Minnesota's VOS tariff is included as Appendix B. A complete breakdown of value components for Minnesota mapped to data sources is included in Appendix C.

distribution substations to 2020 and then screening against planning ratings to identify potential loadings above those ratings. Applying criteria, 16% of National Grid substations were identified as LSRV areas.

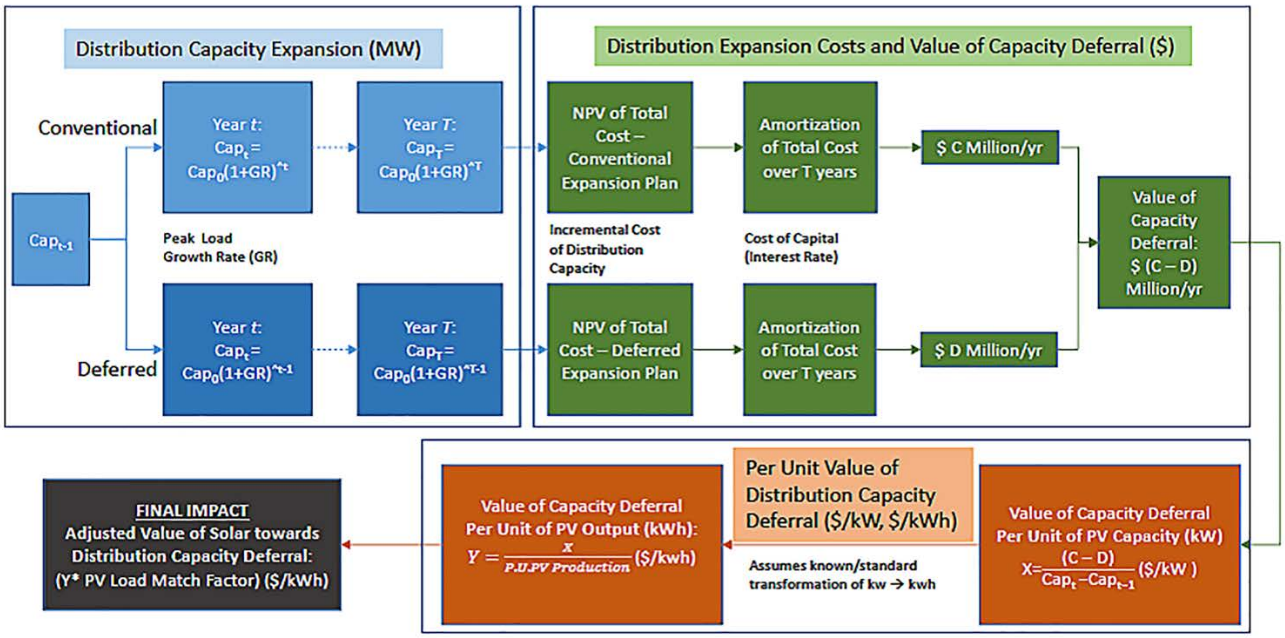

Figure 2. Minnesota Distribution Capacity Value Calculation

Joint Solar Parties also identified elements of the Minnesota approach that they suggest could be replicated in Illinois. These include the distribution capacity value methodology, the long-term outlook of the approach, and its predictability (Joint Solar Parties 2018b). Shortcomings of the Minnesota approach, as identified by the Joint Solar Parties, mainly include lack of transparency and lack of consistent refinement efforts (JSP 2018).

5.0 Data Needs and Key Questions

Different datasets are needed to calculate the value of each element; the data availability, analysis approach, and balance between transparency and privacy for each are also different. Some data and input values are readily available. These include escalation rates based on U.S. Treasury bonds or references, natural gas prices, and solar PV generation data that can be modeled in tools such as NREL's System Advisor Model or PVWatts® Calculator. Other state- and utility-specific datasets needed will vary based on the specific methods used.

Not all types of data are readily available, and other states do not have this complete list. However, data types that will likely be needed to best understand the locational and temporal value of distributed generation in Illinois include the following:

- Load growth projections
- System capacity planning studies – from distribution transformer to bulk system sub-transmission
- Existing and projected distributed generation deployment and production by location
- Line loss studies
- System reliability studies (including voltages, protection, phase balancing)
- System-wide and location-specific cost information, including cost information for potential system upgrades
- System-wide and location-specific peak demand growth rates
- Marginal cost of service studies.

The entirety of data necessary for completing the rebate calculations will become clearer as the valuation elements are decided upon (ComEd 2018a; JSP 2018a). The availability and transparency of data that depict the distribution planning process will allow non-utility stakeholders to better understand the type and granularity of data that currently exist (JSP 2018a). Ameren noted that electrical models, measurement data, and account and costs models will be necessary in order to calculate the rebate, although they are not often available to the public for safety concerns (Ameren 2018a). Other stakeholders emphasized that a regularly updated hosting capacity analysis, DER growth projections, and a GNA will be essential (ELPC et al. 2018a).

From a process perspective, ComEd suggested that it would be more useful to first establish the valuation framework through the Commission process established by FEJA. Once the components of distributed generation value (both positive and negative) are identified, in the specific context of Illinois, only then would a determination be made on the data necessary to support valuation calculations (ComEd 2018b). ComEd suggested that the methodology developed and calculations that support locational, temporal, and performance-based factors necessary to determine the components of the valuation be shared, so long as security and privacy concerns are addressed; however, they pointed out that data just on its own would not provide the locational, temporal, and performance-based factors necessary for valuation (ComEd 2018b).

Ameren noted that in their proposed methodology for calculating the value of distributed generation to the distribution system, the data that will be used for the studies include hourly historical load data, hourly load forecast data, DER generation profiles, and current company planning and reliability criteria to address system capacity needs at each distribution transformer node for a given distribution feeder (Ameren 2018b). Ameren also noted that "costs of system upgrades for the current distribution system snap shot will be compared with costs of system upgrades with DER connected at a given location on the distribution system" (Ameren 2018b), so cost information for system upgrades are another data set that will be used.

Joint Solar Parties also noted that Illinois utilities use embedded cost of service studies in their ratemaking, rather than MCOS studies, but marginal costs are typically used when calculating the value of avoided or deferred investments (JSP 2018a). The difference between embedded and MCOS studies is that embedded cost studies rely on historic or actual costs the utility incurs (the same costs that are used to determine the revenue requirement), whereas MCOS studies calculate what it *would* cost to provide incremental service at the current cost of adding equipment and securing additional power. For each method, there are many different ways to determine relevant costs and their allocations (RAP 2011).

Based on research performed in the development of this white paper, it is likely that as the ICC and stakeholders work together to develop a distributed generation rebate for Illinois, they should be prepared to address the following questions:

- How will distribution areas be defined for the characterization of locational value?
- Will there be standardization and transparency requirements around projecting load growth and distributed generation by distribution area?
- Will utility capital investment plans for distribution areas be required to be developed, filed, and shared? Will they be 5 or 10 year plans? How often will they be updated?
- Will a standardized methodology be developed for calculating components of avoided cost?
- Will details on candidate deferral projects be communicated and made public?
- Will information, data, and analysis results be made available through an online portal?
- Will a consultant be hired to help with developing a rebate value methodology?
- Will there be different distributed generation rebate values for systems with smart inverters and systems without smart inverters?
- Will the distributed generation rebate development be explicitly coordinated with the Adjustable Block Program and other competitive REC procurement programs?
- Does Illinois want to start broadly by looking at the value of DER to the whole grid and then narrow the discussion to the value of distributed generation to the distribution system to put all compensation options (e.g., rebate, REC price, energy supply credit, and future smart inverter compensation) in context?
- Will utilities be required to develop marginal cost of service studies?
- To what extent will data, calculations, and results from analysis and simulation be made public?
- Which, if any, value elements will initially be set to zero and then revisited? What will the time frame be for revisiting?
- How often will value calculations be updated?
- Will a designated working group process be established for developing the distributed generation rebate? If so, how will it be governed and carried out?

6.0 Summary and Conclusions

The investigation the Commission is required to open when the 3% threshold is hit may be broad so that the value of distributed generation to the distribution system is not evaluated in isolation. During that future investigation and the subsequent valuation process, this white paper can provide a reference showing that some stakeholder shared viewpoints already exist. All participants called for transparency and fairness in the development process (Ameren 2018a; ComEd 2018a; ELPC et al. 2018a; Illinois PIRG 2018a; JSP 2018a; REACT 2018A), and several highlighted the importance of ensuring market predictability and promoting a gradual, evolutionary rebate (ELPC et al. 2018a; Illinois PIRG 2018a; JSP 2018a). More explicit ideas, including a hosting capacity analysis and GNA, were also suggested by groups of stakeholders (ELPC et al. 2018a; Illinois PIRG 2018a). Common ground may serve as a starting point for discussion to stimulate progress and reach a final rebate valuation. Ultimately, the ICC makes the decision on distributed generation rebate valuation.

Understanding locational benefits of distributed generation requires understanding infrastructure requirements with and without distributed generation. There are a variety of ways to calculate avoided costs; these are shared in this white paper. In some states, simplified approximations are being used until more detailed modeling and analysis tools become available. In other states, placeholder values are being used and/or certain value elements are set to zero to be revisited in the future. This paper specifically addresses calculation options for the specific value elements of distribution capacity, reduction in losses, and ancillary services (including operating reserves and voltage support).

Data transparency and privacy are issues that also need to be addressed. Stakeholder engagement is important as this process unfolds. California, New York, and Minnesota provide examples of valuation processes that included structured stakeholder engagement and, in the case of California and New York, a deliberate attempt to balance data transparency and privacy.

As the ICC and stakeholders work together to develop a distributed generation rebate for Illinois, this white paper can act as a source of reference material for the rebate calculation as well as a reminder of some of the generally held stakeholder viewpoints.

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Appendix A

New York VDER Tariff Calculation Example

Appendix A

New York VDER Tariff Calculation Example

New York's value of distributed energy resource (VDER) tariffs, also referred to as value stack tariffs, are intended to replace net metering for larger-scale community solar PV projects in the short term, and will eventually be applied to all DERs across the grid. To calculate locational system relief value (LSRV), one of the value components dictated by the New York Public Service Commission, utilities took a multi-step approach. These approaches are described in Table A.1 to provide a specific calculation example from another state with relevance for Illinois, as Illinois statue requires that geographic benefits be considered in the rebate valuation.

Table A.1. Example DER Valuation Specifics from Implementation Plans for Two New York Utilities: Con Edison[1] and National Grid[2]

Step	ConEdison Approach	National Grid Approach
Identification of Locational System Relief Value (LSRV) areas	LSRV areas are those where projected energy use in 2021 reaches or exceeds • 98% of the current capability for high voltage sub-transmission lines that supply area stations; or • 98% of the current capability for area stations that supply distribution network or non-network load areas; or • 90% of the current capability in distribution network areas. Applying these thresholds, just over **19%** of Con Edison service territory is eligible to qualify for an LSRV.	To identify LSRV areas, the company scaled loads on all distribution substations to 2020 and then screened against planning ratings to identify potential loadings above those ratings. 53 specific substations were identified as LSRV areas, representing **16.4%** of the Company's total system load.
	Actual qualification of a project for LSRV compensation will be determined on a project-by-project basis at the time an interconnection agreement is executed with the company.	
Cap limiting the amount of DER capacity that may receive LSRV compensation	Amount of coincident relief that would reduce projected energy use to the point that usage falls below the threshold criteria.	Lesser of the load reduction necessary to reduce peak loading to 100% of planning rating or DER penetration equal to substation minimum load levels (assumed to be 25% of peak load).
Calculation of LSRV and demand reduction value (DRV) rates	Combined LSRV and DRV value in the constrained areas shall be 150% of the current system-wide marginal cost of service level. This technique yields a "de-averaged" **DRV value of $199/kW-year** and an incremental **LSRV of $141/kW-year.**	LSRV set to 50% of its DRV, thereby establishing the combined compensation (i.e., LSRV and DRV) received by LSRV-eligible projects as being equal to 150% of the DRV. Calculations yield an initial proposed **DRV of $61.44/kW-year** and an **LSRV rate of $30.72/kW-year**. Rates to be updated every three years.

[1] Con Edison Implementation Proposal for Value of Distributed Energy Resources Framework, May 1, 2017. Case 15-E-0751 and Case 15-E-0082

[2] National Grid (Niagara Mohawk Power Corporation) National Grid Value Stack Implementation Proposal, May 1, 2017. (Date filed shown as May 3, 2017) Case 15-E-0751 and Case 15-E-0082.

Appendix B

Minnesota VOS Tariff Avoided Distribution Capacity Cost Calculation Methodology

Appendix B

Minnesota VOS Tariff Avoided Distribution Capacity Cost Calculation Methodology

To calculate the system-wide distribution capacity costs, system-wide costs and peak load data must be available for a historical 10 year period. The data sets must represent the same period in time to preserve the inherent connection between growth and investment.

Distribution capacity expansion must be calculated for two cases when determining the associated value of solar in Minnesota—the conventional plan, where traditional development occurs, and the deferred plan, where the conventional plan is delayed for a year because of the introduction of the solar PV system. The difference between these two cases is used to calculate a value of capacity deferral per unit of PV capacity.

Peak load growth rate is necessary to calculate distribution capacity expansion. The methodology requires that

$$GrowthRate = \left(\frac{P_{15}}{P_1}\right)^{1/14} - 1,$$

where P_1 and P_{15} are the peak loads from year 1 and year 15 of the estimated future growth time period.

Beginning with the peak load of the current year, Cap_0, the capacity expansion is calculated for 25 years, the assumed lifetime of the PV system. Thus,

$$Cap_t = Cap_0(1 + GR)^t - Cap_0(1 + GR)^{t-1},$$

where t is the current year being evaluated, Cap_t is the capacity of the current year, Cap_0 is the peak load before the analysis begins, and GR is the growth rate determined above. This is represented through the blue boxes in the flowchart created by PNNL in Figure B.1.

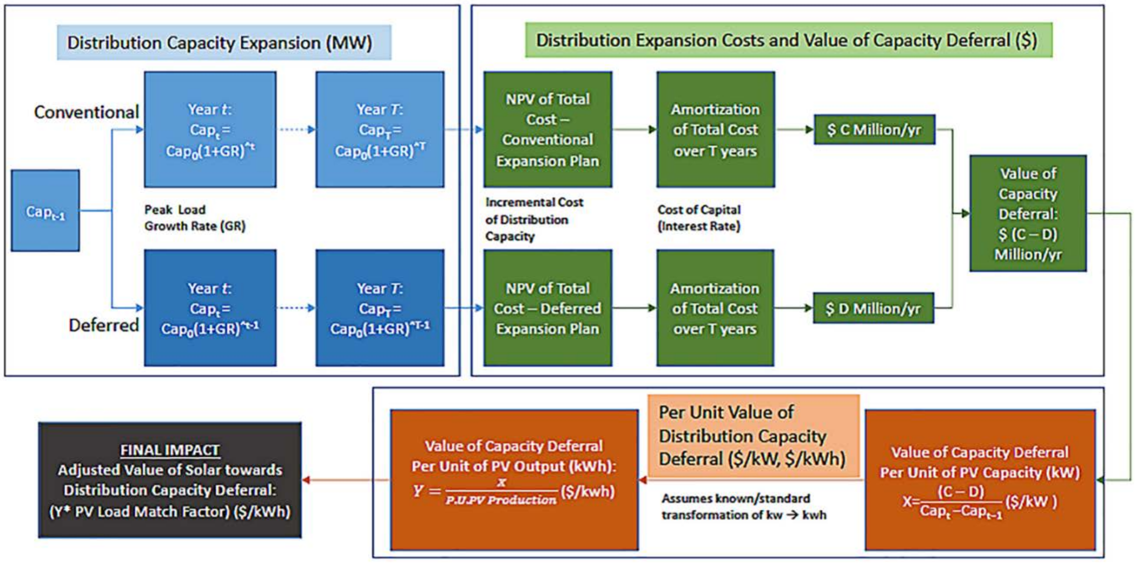


Figure B.1. Minnesota Distribution Capacity Value Calculation

The total net present value of both the conventional expansion plan and the deferred expansion plan are then calculated. The following series of steps is necessary to do so.

Cost per unit growth ($/kW) for the first year of analysis is determined by the historical data. Avoided distribution capacity costs take into consideration costs associated with land and land rights; structures and improvements; station equipment, overhead conductors, and devices; underground conduits; and underground conductors. These values are defined by FERC accounts 360, 361, 362, 365, 366, and 367; however, each utility must determine which portion of the mentioned accounts specifically pertains to distribution capacity and multiply each account by a representative percentage. The sum of the accounts produces the total deferrable costs. After adjusting for inflation, the total deferrable costs value is divided by the kW increase in peak annual load during that 10 year period. The outcome produces the distribution cost per unit growth for the first year.

The subsequent costs per unit growth for the 25 years of analysis (the assumed lifetime of a PV system) are found by escalating the initial cost per unit growth by a utility-provided distribution capital cost escalation rate. This allows the utility to calculate the capital cost for each year by multiplying the year's new distribution capacity by the cost per unit growth. The yearly capital cost is discounted by the utility's weighted average cost of capital. An amortized value for each year is then found from the sum of all discounted capacity costs. The same procedure is performed for the deferred case with the corresponding data (values C and D in the green boxes in Figure B.1).

A value of capacity deferral per unit of PV capacity (kW) is calculated for each year by finding the difference between the conventional plan amortized cost and the deferred plan amortized costs (green boxes in Figure B.1) and then dividing by the conventional distribution planning capacity for the year (orange box in Figure B.1).

This value is divided by the year's per unit PV production to produce the economic value of capacity deferral per unit of PV output (E7 in Figure B.2 and the orange box in Figure B.1). Note that PV production can be either measured or simulated data, provided it complies with the methodology's specifications. Production from the PV system is assumed to degrade by 5% each year (CPR 2014).

The price per kWh is then multiplied by a load match factor and distributed loss savings factor (black box in Figure B.1). The load match factors and distributed loss savings factors in the methodology depend on three categories of time series data over a load analysis period that spans at least a year—hourly generation load, hourly distribution load, and hourly PV fleet production.

Peak load reduction (PLR) is defined as

$$PLR = \max(D_1) - \max(D_2),$$

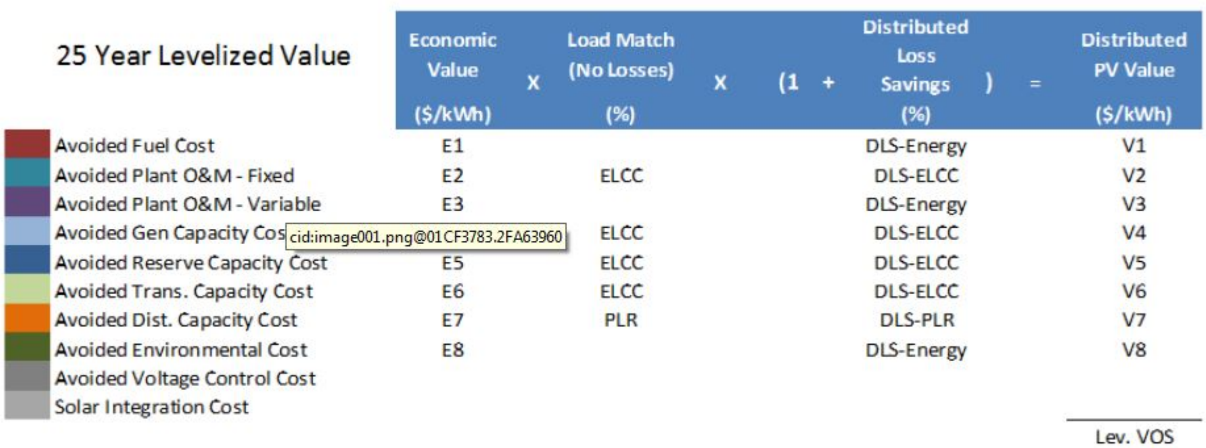
where D_1 is the hourly distribution load time series and D_2 is the hourly distribution load time series minus the effect of the marginal PV resource. The PLR essentially represents the capability of the marginal PV resource to reduce the peak distribution load over the load analysis period. It is expressed in kW peak reduced per kW PV installed as measured on the alternating current (AC) side.

Similarly, a distributed loss savings factor is calculated with the PLR. It is defined as

$$DistributedLossSavings_{PLR} = \frac{PLR_{WithLosses}}{PLR_{WithoutLosses}} - 1.$$

The loss savings factor considers the avoided distribution losses (not transmission) at peak load.

Multiplying E7 by the load match factor and distributed loss savings factor produces the distributed PV value of avoided distribution capacity costs (V7 in Figure B.2).



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 Cos	cid:image001.png@01CF3783.2FA63960		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

Figure B.2. Minnesota Value of Solar Calculation Table (CPR 2014)

The methodology described above is for calculating the system costs and potential savings for distribution. The same basic methodology could be followed with local technical and cost data instead for identified distribution system planning areas, where distribution planning areas are areas where load cannot be easily switched outside of the area (CPR 2014).

Appendix C

Minnesota Valuation Components and Data Sources

Appendix C

Minnesota Valuation Components and Data Sources

Table C.1. Minnesota Valuation Components and Data Sources

Legislative Guidance	Basis	Value Component	Data Sources	Applicable Links and Resources	Notes
Required (energy)	Energy market costs (portion attributed to fuel)	Avoided Fuel Cost	NYMEX (NG Futures), AA-rated Natural Gas Supplier, or Utility	VOS Data Table	
			Standard PV degradation value	0.50%	
			Metered production data from PV plants, Technical applications of PV plants, or PV fleets outside of utility territory		
			US Treasury (escalation rate)	http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield	
Required (energy)	Energy market costs (portion attributed to O&M)	Avoided Plant O&M Costs	Utility	VOS Data Table	
			Standard PV degradation value	0.50%	
			Metered production data from PV plants, Technical applications of PV plants, or PV fleets outside of utility territory		
Required (capacity)	Capital cost of generation to meet peak load	Avoided Generation Capacity Cost	Utility	VOS Data Table	
			Standard PV degradation value	0.50%	
			Metered production data from PV plants, Technical applications of PV plants, or PV fleets outside of utility territory		
Required (capacity)	Capital cost of generation to meet planning margins and ensure reliability	Avoided Reserve Capacity Cost	Utility	VOS Data Table	
			Standard PV degradation value	0.50%	
			Metered production data from PV plants, Technical applications of PV plants, or PV fleets outside of utility territory		
			Utility	VOS Data Table	

Legislative Guidance	Basis	Value Component	Data Sources	Applicable Links and Resources	Notes
Required (transmission capacity)	Capital cost of transmission	Avoided Transmission Capacity Cost	MISO OATT Schedule 9 Charge Standard PV degradation value Metered production data from PV plants, Technical applications of PV plants, or PV fleets outside of utility territory	 0.50%	
			Utility Standard PV degradation value Metered production data from PV plants, Technical applications of PV plants, or PV fleets outside of utility territory	VOS Data Table 0.50%	
Required (environmental)	Externality costs	Avoided Environmental Cost	EPA	http://www.epa.gov/climatechange/ghgemissions/ind-assumptions.html http://www.epa.gov/ttnchie1/ap42/ http://www.epa.gov/oms/climate/regulations/scc-tsd.pdf	
			NaturalGas.org	http://www.naturalgas.org/environment/naturalgas.asp	
			Federal Social Cost of CO_2	http://www.epa.gov/climatechange/EPAactivities/economics/scc.html	
			Minnesota PUC-established externality costs for non-CO_2 emissions	"Notice of Updated Environmental Externality Values," issued June 5, 2013, PUC docket numbers E-999/CI-93-583 and E-999/CI-00-1636.	
			Bureau of Labor and Statistics	ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt	
			Utility		

Legislative Guidance	Basis	Value Component	Data Sources	Applicable Links and Resources	Notes
Required (delivery)	Capital cost of distribution	Avoided Distribution Capacity Cost	Standard PV degradation value Metered production data from PV plants, Technical applications of PV plants, or PV fleets outside of utility territory FERC Accounts 360, 361, 362, 365, 366, 367	0.50%	
Required (capacity)	Load Match Factor	Effective Load-Carrying Capacity (no loss)	Metered production data from PV plants, Technical applications of PV plants, or PV fleets outside of utility territory PTC Rating - California Energy Commission, or standard values provided by methodology Inverter Efficiency Rating - California Energy Commission, or standard values provided by methodology Internal PV Array losses - measured or design MISO BPM-011, Section 4.2.2.4, page 35 -- Hours ending in 2, 3, 4 PM CST in June, July, August	http://www.gosolarcalifornia.ca.gov/equipment/pv_modules.php http://www.gosolarcalifornia.ca.gov/equipment/pv_modules.php https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx	Applied to Avoided Generation Capacity Cost, Avoided Reserve Capacity Cost, Avoided Transmission Capacity Cost
Required (capacity)	Load Match Factor	Peak Load Reduction (no loss)	Utility Metered production data from PV plants, Technical applications of PV plants, or PV fleets outside of utility territory PTC Rating - California Energy Commission, or standard values provided by methodology Inverter Efficiency Rating - California Energy Commission, or standard values provided by methodology Internal PV Array losses - measured or design	http://www.gosolarcalifornia.ca.gov/equipment/pv_modules.php http://www.gosolarcalifornia.ca.gov/equipment/pv_modules.php	Applied to Avoided Distribution Capacity Cost

Legislative Guidance	Basis	Value Component	Data Sources	Applicable Links and Resources	Notes
Required (losses)	Loss Savings Factor	Loss Savings - Energy	Metered production data from PV plants, Technical applications of PV plants, or PV fleets outside of utility territory		Applied to Avoided Fuel Cost, Avoided Plant O&M Cost, Avoided Environmental Cost
Required (losses)	Loss Savings Factor	Loss Savings - PLR	Utility Metered production data from PV plants, Technical applications of PV plants, or PV fleets outside of utility territory PTC Rating - California Energy Commission, or standard values provided by methodology Inverter Efficiency Rating - California Energy Commission, or standard values provided by methodology Internal PV Array losses - measured or design	http://www.gosolarcalifornia.ca.gov/equipment/pv_modules.php http://www.gosolarcalifornia.ca.gov/equipment/pv_modules.php	Applied to Avoided Distribution Capacity Cost
Required (losses)	Loss Savings Factor	Loss Savings - ELCC	Metered production data from PV plants, Technical applications of PV plants, or PV fleets outside of utility territory PTC Rating - California Energy Commission, or standard values provided by methodology Inverter Efficiency Rating - California Energy Commission, or standard values provided by methodology Internal PV Array losses - measured or design MISO BPM-011, Section 4.2.2.4, page 35 -- Hours ending in 2, 3, 4 PM CST in June, July, August	http://www.gosolarcalifornia.ca.gov/equipment/pv_modules.php http://www.gosolarcalifornia.ca.gov/equipment/pv_modules.php https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx	Applied to Avoided Generation Capacity Cost, Avoided Reserve Capacity Cost, Avoided Transmission Capacity Cost

Legislative Guidance	Basis	Value Component	Data Sources	Applicable Links and Resources	Notes
	Cost to regulate distribution (future inverter designs)	Voltage Control			Future (TBD)
	Added cost to regulate system frequency with variable solar	Integration Cost			Future (TBD)

Appendix D
Stakeholder Comments

Stakeholder Comments received after March 1, 2018 workshop

Please note: Ameren Illinois is providing this information as part of a Commission Staff-initiated workshop. Given that these discussions pertain to past litigation and may ultimately culminate in additional contested cases in the future, Ameren Illinois considers this information to be distributed in the context of a confidential settlement discussion, subject to Illinois Rule of Evidence 408.

Ameren Illinois appreciates this opportunity to provide comments related to the Illinois Commerce Commission's March 1 Distributed Generation Valuation and Compensation workshop and the associated Distributed Generation Valuation and Compensation white paper. Developing an accurate, fair, and manageable distributed generation valuation methodology is important to ensure a) customers have appropriate information to base economic decisions, b) utilities can efficiently and effectively manage the distribution system, and c) the State can meet its energy goals.

Ameren Illinois believes that the determination of the value of distributed generation to the distribution system may be guided by a few key concepts.

1. While the term distributed generation will be used throughout these comments to be consistent with the Future Energy Jobs Act (FEJA), a more widely used term that may better encompass the full breadth of technologies and applications that may be connected to the distribution grid is distributed energy resource or DER. Ameren Illinois considers a broad definition of DER in which DER is defined to broadly encompass any generation, storage, or other load managing resource connected to the distribution grid.
2. FEJA calls for an assessment of the value of distributed generation to the distribution system. While distributed generation may provide value in other channels (i.e., generation, transmission, ancillary services), and to various parties (i.e. customer, society, grid), the focus contemplated by FEJA is the value to the distribution system.
3. When considering the value of distributed generation to the distribution system, the valuation should take into account:
    a. The specific location on the distribution system, theoretically down to the distribution line transformer.
    b. The times of day, week, or year it is available, and during what types of weather.
    c. The capabilities the distributed generation can provide (real power, reactive power, or both).
    d. Other distributed generation operating characteristics (ramp rates, voltage support, dispatch ability, etc.)

The February 2018 white paper discusses how other states have addressed valuation and compensation schemes for distributed generation, with an eye toward searching for techniques that may be useful for Illinois to consider. As stated within the white paper, and reinforced at the workshop on March 1, 2018, context is important. No states appear to have adopted identical approaches. Their situations are different. Similarly, the Illinois context is different. Several questions have been posed to help frame the Illinois context and advance the discussion on how to comply with distributed generation valuation contemplated by FEJA. Ameren Illinois responses to the specific questions are provided below.

a) Should the calculated values be limited to the value of distributed energy systems to the distribution network? If not, what other identifiable benefits of distributed energy systems should be included in the values calculated in accordance with Section 16-107.6?

Yes – the calculated values for the distributed generation rebate should be limited to the value of distributed generation to the distribution grid.

b) What are the types of values that distributed energy systems provide to the distribution network?

There are three types of value that distributed generation provides to the distribution system:

1. Avoided distribution capacity costs
2. Reduction in distribution losses,
3. Value of voltage support that may be realized from distributed generation.

There is naturally a small utility operations (O&M reduction) component that could also be included in these three distribution system elements. These all should be based on the particular location on the distribution grid, the capabilities of the distributed generation, and the time of day.

c) How does each type of value that distributed energy systems provide to the distribution network (identified in part (b)) vary geographically?

All three types of value identified in part (b) are directly dependent on the exact location the distributed generation is connected to the distribution system, and the characteristics and load patterns of the circuit to which the distributed generation is connected. For example, if a solar photo-voltaic distributed generator is connected to the distribution at a location up-stream of a capacity constraint, it will have no value to the distribution system to alleviate this particular constraint.

d) How does each type of value that distributed energy systems provide to the distribution network (identified in part (b)) vary across time?

All three types of value identified in part (b) will vary hour by hour, day by day, season by season depending on the load of the circuit and the capabilities of the distributed generation.

e) How does each type of value that distributed energy systems provide to the distribution network (identified in part (b)) depend upon the distributed energy system technology?

All three types of value identified in part (b) will vary with the capabilities of the distributed generation technology. For example, if the capacity constraint on a particular circuit occurs at 6:00 PM on a December day, it is unlikely that a photo-voltaic distributed generator will be capable of providing energy during this time, thus it will have no value to the distribution system to alleviate this particular constraint.

f) What information is necessary to calculate each type of value? Is such information available publicly?

Generally, the types of data necessary include, but are not limited to:

- Accurate Electrical Models
    - Load Models
    - Distributed Generation Models
    - Connectivity Models
- Measurement Data
    - Supervisory Control and Data Acquisition (SCADA)
    - AMI
- Accounting and Cost Modeling
    - Asset Capital and O&M Cost

Generally, for safety and security reasons, this type of data is not publically available.

g) How can each type of value that a distributed energy system provides to the grid (i.e., the systems actual performance) be evaluated?

The operating characteristics of the specific type of distributed generation should be modeled over a specific time period (ex – hourly energy output over a year), and this specific capability compared to the needs of the circuit at the specific location to be connected.

h) If you identified the value of distributed energy systems benefits other than benefits to the distribution network, please address questions (b) – (g) with respect to such other identifiable benefits.

As explained above, the value of the distributed generation rebate should be based solely on the value to the distribution grid.

i) Considering available information, how should distributed generation energy resource benefits be calculated?

The process should generally include:

1. System capacity studies starting at the smallest distribution system asset level (distribution line transformer) then aggregate results upstream towards the bulk supply sub-transmission power transformer. These studies could compare baseline system capacity (current state of the distribution system) against cases of distributed generation penetration at specific locations on the distribution system.
2. System line loss study comparing baseline (current state of the distribution system) against cases with distributed generation penetration at specific locations of the distribution system.
3. System reliability studies including voltage, protection and phase balance comparing baseline (current state of the distribution system) against cases with distributed generation penetration at specific locations of the distribution system.
4. Using the above results, an economic analysis could be used to determine the value of distributed generation at the specified location on the distribution system.

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Illinois Commerce Commission	:	
	:	
	:	
Distributed Generation Valuation and Compensation Workshop	:	
	:	

COMMENTS OF COMMONWEALTH EDISON COMPANY

Commonwealth Edison Company ("ComEd") submits these Comments in response to the solicitation by the Illinois Commerce Commission ("Commission") relating to the March 1, 2018, Distributed Generation Valuation and Compensation Workshop ("Workshop"). Representatives of ComEd attended that Workshop and will continue to participate in subsequent Workshops and other activities on this important topic.

I. Introduction

The Future Energy Jobs Act ("FEJA") requires electric utilities serving more than 200,000 customers in the State of Illinois to request Commission approval of a tariff to provide rebates valued at $250 per kilowatt of nameplate generating capacity, measured as nominal DC power output, to certain customers.[1] The aforementioned rebate value is fixed until the Commission approves subsequent tariffs or tariff revisions pursuant to the findings of an investigation into an annual process and formula for calculating the value of distributed generation to the distribution system at the location at which it is interconnected.[2] ComEd commends the Commission for partnering with the U.S. Department of Energy and the Pacific Northwest National Laboratory ("PNNL") to engage interested stakeholders to review, at this early stage, options being considered in other states for pursuing distributed generation valuation

[1] 220 ILCS 5/16-107.6(b)-(c) and (f).
[2] 220 ILCS 5/16-107.5(e).

methodologies, and for providing a forum for Illinois stakeholders to comment on PNNL's initial Whitepaper[3].

Informed by its unique perspective and the practical experience gained from its long-standing role as Illinois' largest distribution utility and the builder, owner, planner, and operator of the distribution network covering northern Illinois, ComEd recognizes the critical role it is to play in proceedings related to distributed generation. ComEd is active in supporting the integration of distributed generation technology into the distribution system, and it is already developing and implementing a series of demonstration projects meant to test various distributed generation use cases such as storage for grid support, non-wires alternatives, renewables integration, and microgrid operation. ComEd appreciates the opportunity to offer these Comments for Commission, Commission Staff, and other stakeholders' consideration. These Comments reflect ComEd's initial perspectives on the following three topics:

1. The General Assembly's guidance within FEJA for the Commission's future investigation into the valuation of distributed generation in Illinois;
2. The eight questions posed by the Commission for consideration during the Workshop proceeding; and
3. The Illinois-specific portion of the PNNL Whitepaper.

ComEd recognizes that these Workshops are intended engage interested stakeholders and help develop options for the separate and comprehensive effort to discern and shape the future of distributed generation valuation in Illinois. Through these Comments, ComEd's intent is to help inform the transition to an appropriate regulatory construct for future DG rebate amounts reflecting the value of the underlying distributed generation to the distribution system.

[3] AC Orell, *et al.*, Distributed Generation Valuation and Compensation, https://www.icc.illinois.gov/Electricity/workshops/DistributedGenerationValuation.aspx (Pacific Northwest National Laboratory, Feb. 2018) ("Whitepaper").

II. FEJA

FEJA requires that the distributed generation rebate valuation formula approved by the Commission "reflect the value of the distributed generation to the distribution system at the location at which it is interconnected, taking into account the geographic, time-based, and performance-based benefits, as well as technological capabilities and present and future grid needs."[4] In particular, ComEd believes that distribution system level distributed generation compensation mechanisms should adhere to certain guiding principles, including:

- **Objective cost/benefit analysis is critical.** Regulatory policy and structural change should be guided by unbiased, objective cost/benefit analyses that correctly reflect costs to distribution system consumers and the distribution system as a whole. Decisions about how to value and compensate distributed generation should be grounded in such cost/benefit analyses. Objective and unbiased cost/benefit analyses generate information indispensable to parties, facilitating decisions that benefit society.

- **Dynamic Efficiency and Management Flexibility Are Essential.** The final model adopted must allow utility management the ability to adjust to changing circumstances; support and encourage innovation; allow timely implementation of technological advances; promote continuous efficiency improvement; and support long-term value for customers.

Approaches to identify and quantify the value that distributed generation provides are still evolving. As PNNL states, "Certain value elements are difficult or impossible to quantify and most efforts to establish workable value of solar or value of distributed energy resource tariffs are emerging and nascent. Assessing locational and temporal value of distributed generation and

[4] 220 ILCS 5/16-107.6(e).

applying that in compensation schemes is a new and emerging field of study being explored by a handful of research organizations and advanced states and utilities."[5] So, while distributed generation can provide value to the grid, FEJA correctly recognizes that care must be taken and DG rebate values account for their spatial and temporal contributions to the distribution system.

III. Commission's Questions

The Workshop posed the following questions for consideration and comment by stakeholders. ComEd submits the following initial responses below to each of those questions.

a. What's the Illinois-specific context for distributed generation valuation and compensation that is the same as or different from other states?

An important Illinois-specific context to highlight is that, unlike several of the states reviewed in the Whitepaper, Illinois has successfully transitioned to an unbundled rate structure that more clearly identifies the specific costs of the generation, transmission, and distribution components of energy service for customers. Illinois is also a national leader in clean energy policy and distribution system design and development. Our statewide commitment to clean energy and distributed generation is embodied by our Renewable Portfolio Standard ("RPS") and our Zero Emission Standard, provide long-term reliable support for clean energy resources.

b. What approaches from other states may fit or not fit in Illinois and why?

Approaches that are not suited for retail open access states – wherein customers can choose their energy suppliers – will not function in Illinois. The same is true for approaches pursued in states in which the vertical integration of electricity supply, transmission, and distribution is the predominant utility business and regulatory model. The existing regulatory and market structures within Illinois provides consumers a variety of choices including self-generation, community supply, municipal aggregation, and retail supply choice through various

[5] Whitepaper, at iii.

alternative retail electric suppliers. Strategies that do not leverage existing market structures or the proven ability of Illinois' utilities to integrate different supply and retail service offerings may unintentionally over or under compensate distributed generation owners for their facility. States such as California, Oregon, and New York are evaluating or have proposed new distributed generation valuation and compensation mechanisms, each jurisdiction includes different benefits and costs in its calculations, and quantification methods differ across the states. The different approaches employed by other states may be useful in determining the most appropriate approach for Illinois however care must be given ensure that DG rebate amounts reflect the value of underlying distributed generation to the distribution system. While we are still in the early stages of determining the appropriate approach, ComEd agrees that all distribution system level values, both positive (i.e., benefits) and negative (i.e., costs) should be considered in the distributed generation value calculation.

c. What can be gleaned from original FEJA language or other key policies about rebates and valuation objectives and perspectives?

According to FEJA, the rebates provided to distributed generation resources should reflect the value of the distributed generation to the distribution system. ComEd acknowledges that distributed generation installations may provide additional value for society. Present and future market mechanisms (e.g., renewable portfolio standards, wholesale energy and capacity markets, ancillary service markets, tax incentives) may provide opportunities for distributed generation to be compensated for values beyond the value the particular resource provides to the distribution system.

d. What is the relationship to the valuations required by the Adjustable Block Program found in Sections 1-75(c)(1)(K) and (L) of the IPA Act?

Certain distributed generation owners may receive compensation for environmental attributes their systems generate by selling renewable energy credits ("RECs") to the Illinois utilities for RPS compliance. The Illinois Power Agency ("IPA") is required to set a pricing model for these RECs, publish the prices, and offer 15-year REC procurement contracts.[6] The IPA has submitted its proposed pricing model and a Commission decision is expected in April 2018. The IPA has proposed to set the REC price based on all the value streams available to distributed generation owners (i.e. avoided energy costs, rebates, tax incentives) while including a predetermined return on investment that compensates distributed generation owners for the risks associated with ownership of the asset. This program is an illustration of one way in which distributed generation owners' benefit from non-distribution system value streams.

e. <u>What categories of data are or are not available that will influence value calculations?</u>

As a threshold matter, the components of distributed generation value (both positive and negative) must first be identified in the context of Illinois before the determination as to what data is necessary to support the calculations that arrive at appropriate distributed generation values. Data must be robust enough to be applied to computations that calculate the value of the distributed generation to the distribution system as compared to the value of the traditional investment or operational costs it seeks to avoid, considering locational, temporal, and performance-based factors.

f. <u>What are process suggestions or considerations for arriving at distributed generation rebates?</u>

ComEd continues to believe that the process should be guided by a commitment by all parties to arrive at a transparent valuation methodology that is efficient, and equitable. Any methodology for distributed generation valuation and compensation should transparently send

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[6] 20 ILCS 3855/1-75(c).

clear price signals to developers and customers and consider administrative efficiently. ComEd believes that additional process suggestions or considerations are more properly reserved for subsequent proceedings, as those issues are beyond the scope of these Workshops.

g. Which value elements are most important for Illinois?

From a distribution system perspective, the valuation of distributed generation is determined based on the contribution the resource can make to meeting the needs of the distribution system (the "Three R's"): 1) Real power - providing locational load (capacity) relief by reducing consumption during peak or providing redundancy for reliability and resilience; 2) Reactive power - absorbing/injecting reactive power to mitigate impacts of DER (e.g. voltage variations or over voltages); and 3) Reserves - providing standby capacity that can be used during emergencies.

Further, a methodology that values and compensates distributed generation for distribution system benefits should match the capability of the distributed generation to the present and foreseeable future needs of the distribution system. Such a methodology should calculate the locational and temporal value of DER to the distribution system, compare that value to the traditional distribution investment it avoids, allow for implementation across technologies and at various levels of aggregation and, critically, seek to maximize benefits for society.

h. What elements should be considered in differentiating distributed generation value by location?

The value that distributed generation provides to the distribution system varies with the location, time, and performance characteristics in comparison to the alternatives. Thus, any fair pricing or compensation for a distributed generation option should be evaluated based on the following:

1. *What* core product can the distributed generation provide – real power, reactive power, or reserve?
2. *When* can the distributed generation produce the core product?
3. *Where* on the grid is the distributed generation connected?

Thus, the capability of distributed generation is determined based on the contribution the resource can make to meeting distribution system needs through real power, reactive power, or reserve, but the value of that capability is a function of the ability to match it to locations where distribution system upgrades are needed, as well as the hours that are causing the need in that location.

IV. PNNL Whitepaper

The Whitepaper is a helpful guide for considering issues associated with distributed generation valuation and compensation, and it presents useful information about the approaches used in other states.[7] It appropriately recognizes that states with regulatory and market structures as diverse as California and New York (and Illinois) are addressing common questions and issues in somewhat different ways, underscoring the fact that ComEd and other relevant stakeholders must consider factors specific to Illinois when developing the appropriate approach to value distributed generation in the state. The Whitepaper broadly considers FEJA as a whole when interpreting its directives for distributed generation rebate valuation. With these Comments, ComEd provides some needed clarification, and in so doing expresses its preliminary positions regarding the statutory directives for distributed generation rebate valuation, subject to further exposition at the appropriate time.

The Whitepaper reflects upon FEJA's declarations regarding the adoption and deployment of cost-effective distributed generation resource technologies and devices which can

[7] ComEd's comments are not intended to imply that ComEd agrees with every potential element or approach to valuing distributed generation presented in the Whitepaper or employed in the various states.

stimulate economic growth and enhance the continued diversification of Illinois' energy mix, and these generic findings and declarations should be considered within FEJA's entire statutory construct. Specific statutory mandates within 16-107.6 of the PUA should guide valuation discussions and these generic findings may only be considered when there is vagueness or ambiguity within these statutory mandates. As described above, the General Assembly expressly states that the Commission's distributed generation rebate valuations should be based on the value of the distributed generation to the distribution system, thereby providing guidance for the value of the rebates. Environmental attributes are considered through other mechanisms within FEJA, such as the Renewable Portfolio Standard[8] and the Zero Emission Standard.[9]

Additionally, while some may refer to the distributed generation rebate as a smart inverter rebate, ComEd notes that FEJA does not classify the rebate as such. In fact, FEJA requires utilities to offer rebates to certain customers, non-residential customers with distributed generation facilities installed prior to June 1, 2017 enrolled in net metering programs, without requiring a smart inverter. FEJA generally categorizes the rebate as a "distributed generation rebate" without providing specific guidance on the basis for the initial $250 per kW in DC nameplate capacity. For distribution systems installed after June 1, 2017, FEJA specifies that the rebate eligibility criteria include interconnection via a smart inverter and utility operation and control of basic smart inverter functionality under the terms and conditions of the Commission approved tariff.

V. Conclusion

Effective valuation and compensation mechanisms for distributed generation will enable efficient allocation of resources to best improve the planning, operation, reliability, and security

[8] 20 ILCS 3855/1-75(c)
[9] 20 ILCS 3855/1-75(d-5)

of the distribution system for the benefit of Illinois customers, while limiting duplicative or unnecessary investments from either the utility or the distributed generation owners and developers. This requires the consideration of temporal and locational factors to accurately and objectively calculate values. Ultimately, the needs of all customers will be better served if the methodology balances efficiency, accuracy, fairness and transparency.

Ultimate adoption of the methodology for the valuation of distributed generation resources will be driven by many factors, and it will need to be implemented over a reasonable timetable. The collaboration among the Commission, DOE, PNNL, and stakeholders, and the resulting Workshops and Whitepaper, are useful milestones in advancing the discussion of distributed generation valuation in Illinois. ComEd looks forward to the second stakeholder Workshop, and the opportunity to provide additional comments in advance of the final report summarizing options and considerations for the future calculation of distributed generation values in Illinois.

Dated: March 30, 2018

Respectfully submitted,
COMMONWEALTH EDISON COMPANY

By: ______________________
Michael R. Lee
One of its Attorneys

Comments of the Environmental Law and Policy Center, Environment Illinois Research and Policy Center, Vote Solar and the Union of Concerned Scientists
To the Illinois Commerce Commission
Regarding the Distributed Generation Valuation and Compensation Workshop
March 30, 2018

Vote Solar, the Environmental Law and Policy Center, Environment Illinois and the Union of Concerned Scientists appreciate the opportunity to submit comments to the Commission on the implementation of the Future Energy Jobs Act (FEJA) in a manner that will minimize overall system costs and maximize ratepayer benefits from investments in distributed energy resources. Indeed, within the past week the California Independent System Operator announced the cancellation of $2.6 billion in anticipated transmission investments due to load changes attributable to both energy efficiency and distributed solar. Likewise, implementation of the FEJA offers Illinois electricity customers significant benefits in the form of lower system costs, as well as benefits of substantial economic development and improved environmental quality. We are excited to work with the other stakeholders to maximize the promise of these technologies for Illinois.

Vote Solar is a non-profit organization working to foster economic opportunity, promote energy security and fight climate change by making solar a mainstream energy resource. Vote Solar has members across the nation with more than 500 residing in Illinois. ELPC is a not-for-profit organization that works to promote environmentally sound energy policies in Illinois and throughout the Midwest. Joining with citizens across the country, UCS combines technical analysis and effective advocacy to create innovative, practical solutions for a healthy, safe, and sustainable future. UCS has more than 500,000 supporters nationwide, including over 20,000 in Illinois. Environment Illinois Research & Policy Center is a non-profit organization dedicated to protecting air, water and open spaces in Illinois.

With the passage of the Future Energy Jobs Act (FEJA), the Illinois General Assembly adopted a policy to encourage the “adoption and deployment of cost-effective distributed energy resource technologies and devices such as photovoltaics…"[1] In so doing, it listed a wide range of benefits that such technologies (hereinafter, DERs) offer the utility, its customers and the state. Those benefits include stimulating the economy, diversifying the resource mix and protecting the environment, as well as encouraging private energy investment.

To carry out this policy, FEJA includes a number of mechanisms for encouraging investment in DERs, among which is the rebate to distributed generation (DG) owners, intended to eventually replace net metering of distribution charges. At a minimum, that rebate must compensate DG owners for the value of the utility's ability to control the associated smart inverter for reliability purposes during "distribution system reliability events."[2] However, the law sets out a process for determining "additional uses" of the smart inverter that must be separately compensated, as well as for "valuing distributed energy resource benefits to the grid based on best practices, and assessments of present and future technological capabilities of distributed energy resources." The law further explains that "the value of such rebates shall reflect the value of the distributed generation to the distribution system at the location at which it is interconnected, taking into account the geographic, time-based, and performance-based benefits, as well as technological capabilities and present and future grid needs."[3]

Before addressing the specific questions posed by the Commission we want to underscore two critical, overarching challenges for the Commission and stakeholders:

A. Developing Full and Fair Values for DERs Rebates Will Take Time

The worthy goal of establishing a precise and fair methodology for valuing all of the legitimate benefits of DERs before meeting the legal threshold date for transitioning from net metering is on a collision course with the reality noted in the White Paper that, "Certain value elements are difficult or

[1] PA 099-0906 Section (1)(a)(1).
[2] 220 ILCS 5/16-107.6(b).
[3] 220 ILCS 5/16-107.6(e).

impossible to quantify and most efforts to establish workable value of solar or value of distributed energy resource tariffs are emerging and nascent." Many states are beginning the process of developing locational DER valuation methodologies, but even after several years of concerted efforts, leading states with much higher DER penetrations are currently just in the demonstration project phase of this work.

Faced with the need to develop a tariff while the precise science of geographically granular valuation methodologies remain under development, the Commission should consider establishing interim values as placeholders for system benefits that cannot yet be quantified with precision. Several states, including Minnesota[4] and Maine[5], and some utilities have done more general value of solar studies that could be instructive for developing the interim values. Existing value of solar analyses have been summarized by, among others, Jim Lazar for the Regulatory Assistance Project[6].

As the science of DG and DER valuation progresses, Illinois will face the need to refine its own methodologies over time, and in the near term, will need to rely on less than perfect information. Given the overarching goal of FEJA to encourage deployment of DERs, we urge the Commission to adopt a principle that changes in compensation levels should be gradual and designed to avoid market disruption.

B. Developing Full and Fair Values for DERs Requires Increased Transparency and Significant New Data Sharing

[4] *Minnesota Value of Solar: Methodology*, conducted by Clean Power Research for the Minnesota Department of Commerce, Division of Energy Resources by Clean Power Research, April 1, 2014. Online at: http://mn.gov/commerce-stat/pdfs/vos-methodology.pdf
[5] *Maine Distributed Solar Valuation Study*, conducted by Clean Power Research for the Maine Public Utilities Commission, April 14, 2015. Online at: http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-ExecutiveSummary.pdf
[6] https://www.raponline.org/wp-content/uploads/2016/08/rap-lazar-euci-value-of-solar-studies-2016-july-21-2016.pdf

In order to develop locational values, the utility must provide the Commission and stakeholders with critical data, updated on an ongoing basis. At least three types of data needs are required, including:

- A regularly updated hosting capacity analysis. It will be necessary that each utility understand and publicly communicate how much capacity is available on the distribution network, down to the level of individual substations, circuits, and nodes on each circuit. A hosting capacity analysis needs to include a determination of the capability of the distribution system to integrate specific quantities of DERs within thermal ratings, protection system limits and power quality and safety standards. Results of the analyses must be made available to the public in an accessible format that should include circuit level maps and downloadable data sets. Further, utilities need to assess how any planned investments within the subsequent 3 years impact the hosting capacity. The analysis should provide an assessment of the current level of deployment of specific DER technologies, including but not limited to solar photovoltaics or other DG, energy storage systems, plug-in electric vehicles, demand response or other load modifying resources, fuel cells and combined heat and power systems in their services territory and identify circuits that exhibit high levels of penetration. The utilities shall develop a process for regularly updating the hosting capacity analysis. A recent report by the Interstate Renewable Energy Council (IREC) provides guidance for state regulators on conducting hosting capacity analyses that describes new analytic tools used by utilities in states like California, New York and Minnesota to estimate the hosting capacity available on the distribution system for integrating DERs.[7] The Minnesota Public Utilities Commission also required Xcel Energy to conduct an hosting capacity analysis for their service territory in Minnesota, which used a tool developed by the Electric Power Research

[7] IREC, *Optimizing the Grid: A Regulators Guide to Hosting Capacity Analysis for Distributed Energy Resources*, December 2017. Online at: https://irecusa.org/wp-content/uploads/2017/12/Optimizing-the-Grid_121517_FINAL.pdf.

Institute.[8] ComEd's sister company Pepco has also developed and published hosting capacity maps for its circuits in Maryland, Delaware, and New Jersey.[9]

- DER Growth Projections: In order to evaluate the locational benefits and cost of DERs, it will be necessary that each utility have a detailed understanding of the growth trajectories of each type of distributed resource. Therefore, as part of its distribution planning process, each utility should develop long-term (10-year) scenarios that project the growth of DER technologies, including but not limited to solar photovoltaics, energy storage systems, and plug-in electric vehicles. The growth scenarios should also analyze expected geographic dispersion at the distribution circuit level and impacts on forecasted peak and minimum loads. The scenarios should include an expected growth case and a high and low growth case. The assumptions used in the scenarios shall be articulated as part of the distribution planning process.
- Grid Needs Assessment: One component of an ongoing distribution planning process is the preparation of an annual Grid Needs Assessment to be carried out by each utility in a manner that is transparent to consumers and DER providers. The annual Grid Needs Assessment should include identification of specific projects that could be deferrable through investments in DERs that minimize costs to consumers. Data that should be made available through the Grid Needs Assessment process should include:
    - Grid need type such as capacity, voltage/power quality, reliability, resiliency.
    - Location of the grid need including planning area, substation and feeder.
    - Magnitude, timing, duration and frequency of the need (e.g., 1 MW from 3-7pm, max 7 times per month from June-September, max 2 consecutive days).

[8] Punt, C. Minnesota Hosting Capacity Analysis, MIPSYCON, November 8, 2017. Online at: https://ccaps.umn.edu/documents/CPE-Conferences/MIPSYCON-PowerPoints/2017/UIFDERHostingCapacityAnalysis.pdf. Also see Xcel Energy's interactive hosting capacity map for Minnesota here: https://www.xcelenergy.com/working_with_us/how_to_interconnect/hosting_capacity_map
[9] Online at: https://www.pepco.com/MyAccount/MyService/Pages/MD/HostingCapacityMap.aspx

- Planned upgrade (e.g. transformer replacement, reconductoring, line regulator) and its estimated cost.
- Reserve margin needed to provide buffer for contingency scenarios.
- Historical and forecasted data used to identify the grid needs such as load profiles, voltage profiles and reliability statistics.

Specific Answers to the Questions Posed:

a) Should the calculated values be limited to the value of distributed energy systems to the distribution network? If not, what other identifiable benefits of distributed energy systems should be included in the values calculated pursuant to Section 16-107.6?

As a first step, it will be very important to establish a process that attempts to identify and quantify *all* of the benefits of DER to the electricity system. Over the long term, each of these individual values may be valued and compensated through different policy mechanisms, including the DG rebate established pursuant to Section 16-107.6. This will require further evolution of DER policy, including the potential for FERC to establish market participation rules for compensating additional values of DER through wholesale markets. In the interim, the ICC should seek to ensure that DG systems are fairly compensated for the full suite of benefits that they provide to the system. This may require the Commission to establish some interim values as placeholders for system benefits that cannot yet be quantified with precision or cannot yet be compensated through other market mechanisms. As discussed above, the Commission should follow a policy of gradualism and interim steps to avoid unnecessary disruption or uncertainty in DG markets, which would undermine the legislative intent of FEJA.

In order to ensure that the Commission has the necessary data to ensure DG customers are fairly compensated, the Commission should attempt to quantify each of the following benefits of DERs:

1. Avoided capital costs for distribution and transmission upgrades (including capacity, voltage/power quality, and reliability/resiliency upgrades)
2. Avoided distribution operations and maintenance expenses
3. Avoided energy
4. Avoided generation capacity
5. Avoided ancillary services
6. Avoided transmission and distribution system losses
7. Avoided RPS integration costs
8. Avoided environmental impacts, including but not limited to emissions of greenhouse gases and criteria air pollutants.

c) How does each type of value that a distributed energy systems provide to the distribution network identified in part (b) vary geographically?

The value will vary by local load profiles and types of load as well as the characteristics of each circuit and substation. The data needs described earlier in this document will help to determine higher value geographies for siting of and compensation for DERs on the system.

d) How does each type of value that a distributed energy systems provide to the distribution network identified in part (b) vary across time?

The value that is provided across time will depend on local load profiles and changes to those profiles resulting from the performance of the DERs. Again, the data needs described earlier in the document will allow stakeholders to understand both current differences in the value of DERs based on when they provide local grid services, and how those conditions may change in response to anticipated changes in load. Importantly, the Commission should ensure that the compensation to individual DG owners for grid values is fixed at the time of system energization and does not fluctuate over time. The prospective value for *new* DG projects should change over time based on changed conditions on the grid, but stable and transparent pricing for individual projects is necessary to ensure that DG owners can obtain financing for their investments.

The value for other benefits described above will vary over time in different ways. For example, the value of reducing CO2 emissions will change over time based on an increasing carbon price. Avoided energy will also vary over time based on changes in market prices due to a variety of factors, particularly increases in natural gas prices.

e) How does each type of value that a distributed energy systems provide to the distribution network identified in part (b) depend upon the distributed energy system technology?

The values that are provided will be determined by correlation of availability and performance of the specific resource (e.g. solar production profile, amount of energy storage, load shifting potential of DR) and the needs of the local distribution system. At some point in the near future, the Commission will need to address how valuation and compensation for solar systems coupled with storage will differ from stand-alone solar systems.

i) Considering available information, how should distributed generation energy resource benefits be calculated?

Illinois should establish an open process for creating and regularly updating a locational net benefits analysis tool. The tool would be used to set values for DERs and would be updated on a biannual basis to account for changes identified through the updated hosting capacity analysis, grid needs analysis and DER growth projections. Interim values will be used as placeholders for not-yet known or quantifiable values. The updating process would allow for a gradual shift in values over time to move toward the most accurate rebate possible while providing market stability.

Illinois can look to its own energy efficiency stakeholder advisory group (SAG) as an example of how such a process might take shape. Any interested party may participate in the SAG, and parties may contribute the services of technical experts to review data and refine how the cost-effectiveness of particular programs and efficiency measures are evaluated over time. Similarly, a stakeholder process for the DER rebate determination should allow broad participation from any interested party, but should be structured such that parties can opt to participate for the purpose of building consensus on broad policy questions, or to contribute technical resources to review data and attempt to reach consensus on DER values on an ongoing basis. This process both minimizes the number of contested issues brought before the Commission during the tariff proceeding, and creates a firmer shared foundation for understanding whether the policy is achieving the goals for which it was passed, and addressing challenges as they arise.

Similarly, the Minnesota Department of Commerce conducted an excellent value of solar stakeholder process that could be a model for Illinois.

Illinois should establish a budget for the stakeholder group to accomplish its goal of creating and maintaining the valuation methodologies and calculations. The budget could pay for facilitation services as well as technical services. The White Paper pointed out that the California utilities jointly engaged E3 to create a locational net benefits analysis tool which is currently being tested in demonstration projects in advance of a full roll out   Illinois stakeholders may wish to engage a firm to create a similar tool. The budget for both facilitation and technical resources should be capped at a level determined by the commission to be adequate to perform the necessary tasks.

Finally, again the Commission should recognize that establishing precise and granular calculation methodologies will take time. In the interim, it is critical to avoid market disruption that can come from signaling uncertainty about future values or sudden drastic changes in rebate values.

From: Abe Scarr [mailto:abe@illinoispirg.org]
Sent: Sunday, April 1, 2018 12:20 PM
To: Clausen, Torsten <Torsten.Clausen@illinois.gov>
Subject: [External] Re: Distributed Generation Valuation and Compensation

I apologize this are late and hope they will be accepted. I had a plumbing issue to deal with on Friday which distracted me from submitting these by the 3/30 deadline.
thanks
Abe

Re: Distributed Generation Valuation and Compensation

Thank you for the the opportunity to submit comments to the Commission on the implementation of the Future Energy Jobs Act (FEJA) retail customer distributed energy resource valuation and compensation.

Illinois PIRG Education Fund is an independent, non-partisan group that works for consumers and the public interest. Through research, public education and outreach, we serve as counterweights to the influence of powerful special interests that threaten our health, safety or well-being.

Rather than a detailed response to the Commission's questions, our comments present our broader interest in the topics being explored in this workshop. Our sister environmental organization, Environment Illinois Research & Policy Center, has joined a group comment which goes into more detail, which we support.

Distributed clean energy systems provide multiple benefits for individual consumers, consumers as a whole, and society. Studies in multiple states have demonstrated that rooftop solar and distributed clean energy systems, when the full value of the benefits they provide to the electric grid and to society are accounted for, often provide greater value than even the retail rate of electricity.

Considering the significant value these systems provide to the grid and society, compensation mechanisms should be designed not only to deliver fair compensation to retail customers, but also to encourage more Illinois residents to adopt distributed generation systems, further benefiting all consumers and society as a whole.

Distributed clean energy systems benefit the electric grid in many ways, including but not limited to:

- Avoided energy costs;
- Avoided capital and capacity investment;
- Reduced financial risks and electricity prices;
- Increased grid resiliency; and
- Avoided environmental compliance costs.

Distributed clean energy systems further provide valuable benefits for society, including:

- Avoided greenhouse gas emissions;
- Reduced air pollution that harms public health; and
- Local job creation.

A detailed accounting of these benefits will take time and will require increased data transparency so all stakeholders have access to the same information. This includes a regularly updated hosting capacity analysis, distributed energy resource growth projections, and a grid-needs assessment.

As this detailed accounting with equal access to data is performed, the commission should avoid signalling uncertainty about future values or make drastic changes in rebate values, so as not to discourage customer adoption of distributed clean energy systems.

Again, thank you for the opportunity to provide comment.

--
Abraham Scarr

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INFORMAL INITIAL WRITTEN COMMENTS
OF THE COALITION TO
REQUEST EQUITABLE ALLOCATION OF COSTS TOGETHER ("REACT")[1]

The Coalition to Request Equitable Allocation of Costs Together ("REACT") commends the Illinois Commerce Commission ("Commission") for working with the United States Department of Energy (DOE) and the Pacific Northwest National Laboratory (PNNL) to develop and publish the Distribution Generation Valuation and Compensation White Paper (the "White Paper"). REACT appreciates the opportunity to provide these initial Comments on Distributed Energy Resource ("DER") valuation and related issues. REACT includes large energy users who own and operate on-site generation at their facilities, as well as developers who work with large energy users and others to develop DER.

As it considers grid modernization and customer empowerment issues, the Commission should recognize that there are a variety of DERs that add value to the grid, and that should be compensated in a manner that provides price signals accurately reflecting their value.

Scope of the Investigation

As an initial point, it should be noted that this investigation extends beyond examining the value of "distributed generation." Section 16-107.5(e) defines the scope of the Commission's investigation:

> When the total generating capacity of the electricity provider's net metering customers is equal to 3%, the Commission shall open an investigation into an annual process and formula for calculating the value of rebates for the retail customers described in subsections (b) and (f) of this Section that submit rebate applications after the threshold date for an electric utility that elected to file a tariff pursuant to this Section. **The investigation shall include diverse sets of stakeholders, calculations for valuing distributed energy resource benefits to the grid based on best practices, and assessments of present and future technological capabilities of distributed energy resources.** The value of such rebates shall reflect the value of the distributed generation to the distribution system at the location at which it is interconnected, taking into account the geographic, time-based, and performance-based benefits, as well as technological capabilities and present and future grid needs.

(220 ILCS 5/16-107.5(e). Emphasis added.) Thus, this investigation is not limited to valuing "distributed generation," but rather includes all "distributed energy resources," which includes "distributed generation," but also includes a variety of other resources. For example, the North American Electric Reliability Corporation ("NERC") defines DER as follows:

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[1] These Comments are preliminary and necessarily incomplete, given that the Commission has just begun substantive discussions on specific issues and the comments of other stakeholders have not been considered prior to the submission of these Comments. REACT reserves the right to respond to additional questions and provide additional or different Comments as this process evolves.

> A Distributed Energy Resource (DER) is any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electric System (BES).

(NERC, "Distributed Energy Resources, Connection Modeling and Reliability Considerations," Feb. 2017 at 1, https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf (last visited March 30, 2018).) As such, DER includes distributed generation, behind-the-meter generation, energy storage facilities, distributed energy resource aggregation, micro-grids, and cogeneration. (*See id.*) Other utility commissions have recognized that it also is appropriate to include energy efficiency and demand response in the definition of DER. (*See* White Paper at 15.)

<u>The Importance of Context</u>

As recognized in the White Paper, a critical preliminary step in the valuation process is to understand the goals that the State wants to achieve. (*See id.* at 2.) Over the years, the General Assembly has provided that context for the Commission.

The first sentence of the Illinois Public Utilities Act ("PUA") sets forth the State's touchstone goals:

> The General Assembly finds that the health, welfare and prosperity of all Illinois citizens require the provision of **adequate, efficient, reliable, environmentally safe and least-cost** public utility services **at prices which accurately reflect the long-term cost of such services and which are equitable to all citizens**.

(220 ILCS 5/1-102. Emphasis added.) The PUA then suggest that all regulations should be in-line with advancing those overarching goals, and that the regulations should seek to ensure efficiency, environmental quality, reliability, and equity. (*See id.*)

With the Electric Service Customer Choice and Rate Relief Law of 1997 (the "Customer Choice Act"), the General Assembly noted that the State had been well-served by comprehensive regulation to achieve these goals, but given the changes in the electricity markets, the State would be best served by enabling competitive market forces for electricity supply. (*See* 220 ILCS 5/16-101A(a), (b).) As a result, the Commission was directed to "**promote the development of an effectively competitive electricity market** that operates efficiently and is equitable to all consumers." (220 ILCS 5/16-101A(d). Emphasis added.)

Most recently, the General Assembly recognized that the investment in smart grid technologies "**empowers the citizens of this State to directly access and participate** in the rapidly emerging clean energy economy while also presenting them with unprecedented choices in their source of energy supply and pricing." (P.A. 99-0906, Section 1.)

The General Assembly then articulated the specific goals associated with this next step of the electric restructuring process:

> To ensure that the State and its citizens, including low-income citizens, are equipped to enjoy the opportunities and benefits of the smart grid and evolving

> clean energy marketplace, the General Assembly finds and declares that Illinois should continue in its efforts to build the grid of the future using the smart grid and advanced metering. infrastructure platform, as well as maximize the impact of the State's existing energy efficiency and renewable energy portfolio standards. Specifically, the Generally Assembly finds that:
>
> > (1) **the State should encourage: the adoption and deployment of cost-effective <u>distributed</u> <u>energy</u> <u>resource</u> <u>technologies</u> and devices**, such as photovoltaics, which can encourage private investment in renewable energy resources, stimulate economic growth, enhance the continued diversification of Illinois' energy resource mix, and protect the Illinois environment . . ..

(*Id.* Emphasis added.)

Thus, applying the guidance provided by the General Assembly, the Commission should support advancement of cost-effective DERs, primarily through the promotion of an effectively competitive electricity market, with regulation where necessary to continue to ensure adequate, efficient, reliable, environmentally safe and least-cost service with equitable rates that accurately reflect the long-term costs of providing service.

<u>The Unique Value Associated With C&I Behind-The-Meter DER</u>

As reflected in the definitions of DER used by NERC and other state commissions, DER systems are non-utility scale technologies used to provide (or avoid the consumption of) electricity, as an alternative to utility-scale generation connected to the transmission system. DERs can reduce the need for new generation capacity, reduce wholesale capacity prices, reduce wholesale energy prices, reduce transmission and distribution costs, and improve system reliability and resilience. DERs also can create benefits that are experienced by society in general, such as reduced environmental impacts, regional and local economic development, and job growth. It would be appropriate for the Commission to take into consideration all of these benefits as it investigates and adjusts the utilities' rates.

REACT also respectfully requests that, as part of this investigation, the Commission recognize the unique value that commercial and industrial ("C&I") customer on-site DER provides to the grid. In Illinois, to the extent that C&I customers do not have behind-the-meter DER, most purchase the commodity of electricity from an alternative retail electric supplier ("ARES"), and have the electricity delivered by the transmission and local distribution utilities. Behind-the-meter DER provides the important benefits of lowering the power needs from utility-scale power plants, improving reliability and resilience, and reducing the need for transmission and distribution system upgrades. In this regard, behind-the-meter DER can be thought of as "locally sourced" electricity.

Behind-the-meter DER includes cogeneration, combined heat and power, reciprocating engines, and other generation or energy storage systems installed on the customer's premises to provide all or a portion of the customer's electricity supply requirements. This type of DER differs significantly from many of the solar and wind distributed generation projects that may not be located on a customer's premise. For example, a customer who is part of a community solar or wind project will receive a financial payment or utility bill credit for electricity that is generated remotely and passed through the distribution system, whereas as behind-the-meter DER displaces utility-delivered electricity, helping the grid operate more efficiently and at a lower cost, since less electricity needs to be delivered by the utility. Many of these on-site DER systems also are more reliable than solar and wind, in that they have their own fuel source that can be available for extended time periods at relatively constant capacity levels, and are not dependent on the sun shining or the wind blowing to produce electricity.

This means that a valuation of behind-the-meter DER should include not only the displaced energy "commodity" costs associated with the particular resource, but also all fixed related "avoided" costs associated with transmission and capacity. As reflected in the White Paper, other states, including Minnesota, Oregon, California, and New York already have embraced providing transmission and capacity credits for DER. (*See* White Paper at 9-13.) However, in Illinois the developer of a community wind or solar project will receive capacity payments, but large C&I customers with on-site generation are not provided with any capacity payments for their "iron in the ground" investments, and also have substantial transmission and capacity related cost risks.

For example, in the Commonwealth Edison Company ("ComEd") service territory, all utility customers -- including those with on-site generation -- pay for ComEd transmission and PJM capacity based on their Peak Load Contribution ("PLC") during the five highest ComEd and PJM system peak hours, which usually occur during the summer months of June to September (but can occur at any time). The five peak hours may not be the same for ComEd and PJM and are not known until after the summer period. Thus, these customers run a risk of incurring significant, unjustified charges if their on-site generation happens to be off-line or not operating at full capacity during one or more of these "peak" hours; if that occurs, the customer could end up receiving an inaccurate and inflated PLC, which would mean significant additional costs based on a measurement that fails to properly account for the existing DER at the customer's facility.

As shown in Table 1, these additional charges can be significant:

Table 1. Annual Transmission and Capacity Charges - ComEd Zone
Charges Assume 1 MW (1,000 kW)

PJM Capacity Charge - ComEd	June 1, 2017	June 1, 2018	June 1, 2019	June 1, 2020	
Capacity Price (Daily Charge)	$154	$212	$191	$183	/MW
PLC Obligation	1.00	1.00	1.00	1.00	/MW
PJM Pooling Requirements Factor	1.0967	1.0905	1.0881	1.0500	
PJM Zonal Scaling Factor	1.0530	1.1743	1.1137	1.0697	
Adjusted PLC Obligation	1.1548	1.2806	1.2118	1.1232	/MW
Daily Charge	$177	$272	$231	$206	
Annual Capacity Charge	$64,748	$99,103	$84,427	$75,082	/MW
ComEd Transmission Rate					
Annual Charge	$34,392	$34,392	$34,392	$34,392	/MW
PLC Obligation	1.00	1.00	1.00	1.00	
Annual Transmission Charge	$34,392	$34,392	$34,392	$34,392	
Total PJM Cap. & Trans. Charge	**$99,140**	**$133,495**	**$118,819**	**$109,474**	

Notes
a. June 2019 and 2020 capacity rates based on first incremental auction results. Supplemental auctions will slightly adjust these rates.
b. Annual transmission rate is updated each June 1. Assumed no change in rate for June 2018 to June 2020 period.

Thus, it is estimated that for the ComEd service territory the annual transmission and capacity related charges for customers beginning in June 2018 will be approximately $130,000 per MW; starting June 2019 annual charges will be nearly $120,000; and starting June 2020 they will be approximately $110,000 per MW.

Although some customers with on-site generation currently may use the PJM demand response program to mitigate their capacity risk, it would be more efficient if customers were able to directly access those markets themselves. Moreover, the demand response market does not fully compensate customers for the value they are providing. The calculation of the value that customers with on-site generation provide is simply the other side of the coin of the transmission and capacity charge calculation, since those charges are cost-based. That is, for each MW of on-site generation, they should receive an annual credit equal to the annual per MW transmission and capacity related charges, since that calculation should reflect the costs that are avoided as a result of that MW of on-site generation.

Since large C&I customers with on-site generation typically have systems in the range of 5 MW, the value they are providing is in excess of $500,000 per year. The current utility rates contain nothing to reflect this value. REACT respectfully requests that the Commission investigate revising those rates to accurately reflect the value that is being provided.

Finally, in order to further promote the development of effective electric markets for DER, the Commission also should consider tariffs that would empower customers to directly access the grid to sell their DER. Currently, the utilities' tariffs only allow such access to Qualifying Facilities.

Additional Steps To Encourage DER

Consistent with the General Assembly's guidance that the State should take steps to "encourage[] the adoption and deployment of cost-effective distributed energy resource technologies and devices," the Commission should conduct a comprehensive investigation with the goal of removing any and all regulatory burdens that unnecessarily inhibit the further deployment of DER. (P.A. 99-0906, Section 1.) In particular, the Commission should:

- Revise the interconnection process to require additional transparency. The process in Illinois should closely mirror the successful FERC / PJM process which includes a public queue and requires interconnection studies and agreements to be filed with the regulator. The Commission also should develop clear guidelines with respect to the type, scope and level of acceptable interconnection costs, and require utilities to provide full and complete supporting documents for their cost estimates.

- Investigate the circumstances under which customers should be entitled to self-build distribution system upgrades, consistent with the utility's requirements.

- Acknowledge that all DER is subject to either ICC or FERC oversight and regulation. The Commission should create a bright line definition to ensure that lower voltage facilities that qualify to become transmission under the FERC seven factors test do indeed become transmission. Jurisdiction over DER should be complete and seamless; there should be no suggestion that some form of DER "falls through the regulatory cracks."

- Recognize in its regulations that payments to the utilities for Commission-jurisdictional DER interconnection costs are not taxable income. Inappropriate tax treatment of these costs artificially inflates the upfront project costs and discourages otherwise cost-effective deployment of DER.

Conclusion

REACT appreciates the opportunity to present these initial Comments, and looks forward to working with the Commission and interested stakeholders in this process to develop equitable and accurate rates that reflect the unique value that C&I behind-the-meter DER provides to the grid as well as fair regulations that encourage cost-effective DER.

INFORMAL COMMENTS ON BEHALF OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION, THE ILLINOIS SOLAR ENERGY ASSOCIATION, AND THE COALITION FOR COMMUNITY SOLAR ACCESS (THE JOINT SOLAR PARTIES)

I. Introduction

The Solar Energy Industries Association ("SEIA"), Illinois Solar Energy Association ("ISEA"), and the Coalition for Community Solar Access ("CCSA") (collectively "Joint Solar Parties" or "JSP") appreciate the opportunity to provide input on the Illinois Commerce Commission informal Distributed Generation Valuation proceeding.

Established in 1974, SEIA is the national trade association of the United States solar energy industry and is a broad-based voice of the solar industry in Illinois. Through advocacy and education, SEIA and its 1,000 member companies are building a strong solar industry to power America. There are 34 SEIA member companies in operation in Illinois working in all market segments – residential, commercial, community solar, and utility-scale – representing millions of dollars of in state investment and a significant portion of Illinois' 4,000 solar jobs. SEIA member companies also provide solar panels and equipment, financing, and other services to a large portion of Illinois solar projects. Established in 1975 ISEA, which has approximately 600 business and individual members, educates and advocates for the advancement of solar development in Illinois. The Coalition for Community Solar Access is a national Coalition of businesses and non-profits working to expand customer choice and access to solar for all American households and businesses through community solar.

The Joint Solar Parties have board collective knowledge and experience through participating in Distributed Energy Resources (DER) valuation proceedings around the country. We look forward to working with the ICC and other stakeholders to develop long-term solutions that adequately value the benefits that DERs bring to Illinois residents and the grid in general.

A. Overarching Goals and Objectives

Establishing protocols for properly valuing the benefits of distributed energy resources ("DERs"), and devising ways to unlock those benefits, is not a simple task. Public Act 99-0906 created a multi-tiered process to provide full value to DERs. Some of those aspects, including the value of Renewable Energy Credits (RECs) and net metered supply, have been handled in other contexts (*e.g.* ICC Docket No. 17-0838 (LTRRPP approval); ICC Docket No. 17-0350 (ComEd community solar tariff).) In anticipation of approval of a tariff pursuant to Section 16-107.6(e) of the Public Utilities Act, this informal process addresses a specific subset of these overall values, specifically the value "to the grid." (*See* 220 ILCS 5/16-107.6(b), (e).)

This process is both similar to and distinct from other states. On one hand, efforts are underway in a number of states to determine the value that solar provides to the grid and consumers, but as yet they remain largely in the early stages. At issue are not only the methods by which DER benefits are calculated, but also the processes used to establish and refine discrete elements; the designs of tariffs and programs through which the values flow, how these aspects affect the marketplace for DERs, DER customers, non-DER customers, and utilities, and the overall state policy context. On the other hand, some of the jurisdictions considering value of solar are either vertically integrated or address most (if not all) values of solar through the utility. Neither experience can be simply superimposed on Illinois, although other jurisdictions have had to address the issues related to values to "the grid" that Illinois will have to address. This DER valuation process should be considered one piece of an overall puzzle to allow and encourage DER market development in Illinois.

Given the wealth of issues that must be considered, the Joint Solar Parties believe it is critical that Illinois first establish core objectives for its DER valuation framework as a guide for future decisions.

Illinois Supports Expanding Distributed Generation

In its Resolution initiating the 'NextGrid' Grid Modernization Study, the Commission recognized the pace of change being brought about by distributed degeneration and related technologies, the need for Illinois' electric industry and regulatory processes to evolve to meet the many challenges presented by this evolving industry, and the promise of even greater future consumer and societal benefits as the electric system moves towards the integration of distributed energy resources. The Resolution envisions the NextGrid report to lay out issues, opportunities and challenges, identify areas of consensus and disagreement, and provide a range of recommendations aimed at empowering customers, driving economic development, optimizing the electric utility industry, and creating a 21st Century regulatory model that supports innovation.

Just as the work Illinois has done to unlock competition in the electric industry has evolved and yielded benefits over the past two decades, this next wave of regulatory reform and market development will also evolve over the next two decades. The NextGrid report will help regulators and other policymakers map out the work needed to reach the ultimate goals.

This Value of DG proceeding, and the subsequent tariff, should be viewed in the context of Illinois' overall vision of evolving a 21st Century regulatory model, its desire to dramatically grow new solar installations – and the corresponding economic development – and its stated desire to maintain its leadership in energy policy and its goal of enabling customers to better manage their energy use and control its cost. The tariff to be in place upon reaching the 5% net metering cap should be viewed as an early step in this long evolution.

The Future Energy Jobs Act (FEJA) and Illinois' NextGrid proceeding both recognize that our electricity grid is evolving. Markets should be transparent and the market signals must be clear to all participants.

After FEJA, both the Illinois Power Agency Act and the Public Utilities Act make clear the directive and mandate to the Commission to support new development of solar resources, including distributed solar resources. Section 1-75(c)(1)(C) directs the Illinois Power Agency by 2030 to procure 2,000,000 RECs annually from distributed and community renewable generation powered by PV solar that was built after June 1, 2018. (*See* 20 ILCS 3855/1-75(c)(1)(C).) The new build wind and solar requirements—including the 2,000,000 annual RECs from distributed and community renewable generation powered by PV solar—explicitly take precedence over the top-line RPS requirements. (*See* 20 ILCS 3855/1-75(c)(1)(B).) In order to put the Illinois Power Agency in the best position to meet these goals, the value of PV solar DERs must be fairly compensated. Indeed, fully enabling this emerging market to grow and scale will be critical to realizing the many benefits sought by NextGrid.

We must ensure the grid framework incorporates the full value of consumer-centered resources and technologies and provide a pathway for DER-enabled grid solutions we can't yet imagine. These DER assets stay connected to the utility system and the two work together to produce a more reliable, resilient, low-carbon energy system. DERs should be viewed as an opportunity. We should welcome and encourage power created by the people, for the people and create structures that allow the market to develop.

DERs Provide a Wide Range of Services to the Grid

Value to the grid is a new area of interest for utilities and distributed energy resources alike, there are a host of services DERs like solar and solar+storage (a single system that combines solar and storage) can provide. These services do not need to be activated all at once, and the value of DER tariffs should contemplate how these assets are activated and valued over time. The system owner must be fairly compensated for the additional benefits offered to the grid. Grid services can include, but are not limited to:

- **Versatile demand response** participation that avoids transmission and distribution line losses.
- **Localized distribution support** programmed for specialized load shifting, variable by month/day/hour, to support targeted load shift or voltage support.
- **Increased renewables hosting capacity** to reduce risk of backfeed and enable higher renewables and electric vehicle penetration.
- **Real-time data sharing** on asset performance, customer loads, and local grid attributes monitored via revenue-grade metering.

To evaluate the identified compensation structure options, we encourage the ICC to first develop criteria and objectives to help guide the creation of DER valuation structure.

Foundational Goal and Principles

As discussed in further detail throughout the body of these comments, the chief goal should be supporting sustainable, long-term, and stable DER market development through the realization of the full benefits DERs can provide. We identify the following objectives and principles as essential to achieving this goal.

<u>1. Ensuring Financeability</u>: Neither the full benefits of DERs, the full 2,000,000 RECs annually required by Section 1-75(c)(1)(C) of the IPA Act nor the ultimate vision expressed in the Resolution initiating the NextGrid proceeding will be realized under conditions where deployment is frustrated by uncertainty over compensation for DER benefits. Of central importance in this respect is that DERs have a capital structure much more like traditional utility grid investments, like a substation or a distribution line, than fossil fuel generating plants. Specifically, DERs (and grid assets) tend to be characterized by large up-front capital costs and relatively smaller ongoing costs such as operations and maintenance.

Scaling DERs therefore requires financing, the availability of which in turn hinges on the establishment of long-term, stable economic signals to providers, and predictable compensation for customers.

While the exact definition of 'financeability' may vary depending on the customer and project type (residential rooftop solar system or a community solar developer), financing for all customers requires predictability and long-term stability.

Apart from revenue predictability, a central element of ensuring financeability is setting a long-term price signal up front, so the developer and their financing partner(s) have clear vision into the long-term revenue stream. This is comparable to the difference between having a long-term PPA compared with selling into the hourly market, or even short-term contracts in the bilateral market. The PPA approach is similar to setting the price of the value of DER at the time of planning and construction—again, just as distribution grid components are compensated—rather than having the potential upside coupled with unpredictability and risk of a constantly-changing revenue stream. Additionally, existing systems should be able to 'opt in' to any new technical requirements (and associated revenue streams) after the initial rebate is issued.

2. Creating Market Stability & Predictability: Illinois law places certain constraints (discussed further in subsequent sections) on the timeframe for the development and deployment of a methodology for determining the distribution value of DERs. In order to support a smooth transition to the beginning of a new value-based regime, the development of the methodology and character of value-based compensation needs to display a sense of urgency so that it can be deployed and implemented in line with statutory requirements, and DER providers and prospective customers can adequately prepare for it.

Additionally, consumer protection should be kept front-of-mind in considering market stability. If consumers can't understand complicated new rates and respond to them appropriately, their financial well-being is jeopardized. Because of these constraints, a smooth transition that consists of smaller, reasonable changes in a stepped process is appropriate.

Additionally, even during conversations of new methodologies to value DERs, a customer's right to offset and manage their own load should be protected.

3. Evolution Over Time: The Commission should recognize that objectives (1) and (2) necessitate that the framework embody an evolutionary character that supports both timely implementation, as needed, and gradual refinement as more and better information becomes available. As evidenced by similar efforts taking place in other states, developing a finely tuned, locally-differentiated valuation methodology is a time-consuming process – and one which has not been demonstrated in any state to date. It demands extensive collaboration between stakeholders and is often frustrated by a lack of data suitable for establishing reliable valuations. In addition to allowing for refinement, it allows for consideration of impacts based on customers. Developers and their customers need simple, easy to understand value of solar price signals, and they need time to adjust to market signals. Moreover, transitioning to a service or value-based regime requires a fundamental rethinking of the distribution planning process which itself is a long-term process.

As discussed previously, this DG tariff fits within the overall NextGrid proceeding - it is one mechanism that the Commission has to implement NextGrid. And it is a mechanism that will need to evolve over time (for new systems) with early forms having placeholders for data that we do not have yet – either because utilities do not currently collect it in a useable and shareable format or because such data is not yet knowable due to the yet-to-evolve distribution planning and utility business models.

Furthermore, when considering how the DG Value tariff – both the structure and value – will impact the further development of solar in the state, the Commission should apply the principle of gradualism in its decisions.

4. Transparent and Participatory Processes: Developing valuation methods is a highly technical exercise that demands extensive stakeholder collaboration and expert input. Working group formats, as have been used in other states, can be an effective way to develop proposed methods and accomplish related goals (e.g., defining data availability and needs). However, their effectiveness is compromised when they lack formal mandates or backing, or clear objectives, deliverables, timelines, and effective facilitation. We recommend that one or more working groups be established, consistent with the characteristics described above, for the purpose developing valuation proposals and that these working groups be overseen by a neutral facilitator who reports to the Commission. The working group proposals can then be presented for party comment in a more formal setting. It is critical that the groups be backed by a mandate that utilities be full participants obligated to work collaboratively with stakeholders and fully share information and data necessary for the group to accomplish its tasks.

5. Valuation Must Use a Long-Term Perspective: The valuation methodology itself must reflect a long-term perspective consistent with the operating lifetime of DERs. DERs that function as replacements for other long-term investments generate value throughout their lifetime. Evaluating their value based on a more limited time horizon is inconsistent with how a comparable traditional infrastructure investment would be valued.

The need for long-term values was recently recognized by the California Public Utilities Commission (CPUC), which is the most advanced in developing locational values. In Decision 17-09-026 the CPUC determined that distributed energy resources had distribution level benefits beyond the utilities' distribution planning horizon and that those long run benefits needed to be accounted for in determining the value of a distributed energy resource at any location on the distribution grid.[1] Illinois similarly should adopt a long-term approach to fully compensate the value in deferring or replacing distribution system upgrades or other values to the grid.

A. Responses to Requests for Comment

Our comments address both the questions posed in advance of the March 1st workshop and the supplemental questions posted on the Commission's DER workshops page on or around March 21st. We have chosen to address both sets of questions because both sets reflect important aspects for the development of a DER valuation framework. In this respect, we are aware that the Commission Staff's addition of the supplemental questions states a preference for comment on

[1] See CPUC D.17-09-026 at p. 46 and p. 49-50
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M196/K747/196747754.PDF

technical value calculations. However, the topic of technical value calculations cannot be divorced from the process that is used to reach such conclusions – consideration of technical value calculations is best suited to a formal stakeholder proceeding where stakeholders have access to necessary data upon which to base any assumptions and calculations. Therefore, these comments should be viewed as a framework for future discussions and identification of selected current knowledge gaps, rather than end conclusions about precise valuation. The latter simply is not feasible at this time given the availability of relevant data. Additionally, these comments should be viewed as the beginning of a conversation about how the Value of DG tariff should be structured and which values should be considered and the JSP reserve our right to identify and quantify additional value streams in the future, both in this informal comment process and future docketed proceedings.

II. Workshop Agenda Questions

A. What's the Illinois-specific context for distributed generation valuation and compensation that is the same as or different from other states?

<u>Illinois' Use of a Rebate is Unique but Manageable if Done Correctly</u>

States have typically performed evaluations of DER value so as to arrive at a levelized long-term rate denominated in $/kWh, often for comparison to an applicable retail rate. Illinois law by contrast states:

> [C]alculations for valuing distributed energy resource benefits **to the grid** based on best practices, and assessments of present and future technological capabilities of distributed energy resources. The value of such **rebates** shall reflect the value of the distributed generation to the distribution system at the location at which it is interconnected, taking into account the geographic, time-based, and performance-based benefits, as well as technological capabilities and *present and future grid needs*.[2] [Emphasis added]

The statute both identifies a narrow set of values—"value of the distributed generation to the distribution system at the location where it is interconnected"—and also a far broader set of values "benefits to the grid." These parallel (i.e. separate) requirements must both be analyzed.

The difference embodied by the statutory requirement that "value . . . to the distribution system" be reflected in a rebate does not necessarily require a wholly unique valuation methodology relative to those used elsewhere. In many ways, this uniquely sets up Illinois to capture the long-term approach proposed above with a rebate value that takes into account a 25-30 year horizon of benefits to the distribution system both at present and in the future.

We also observe that Illinois law establishes that smart inverter tariffs must provide for separate compensation for "additional uses" of the smart inverter. Thus, in order to be consistent with Illinois law, compensation includes:

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[2] 220 ILCS 5/16-107.6(e)

- *An Up-Front Payment:* Section 16-107.6(g) makes clear that both before and after the Commission sets a value of solar calculation, the customer (or in some cases the developer) must be provided a rebate within 60 days of an application.
- *Ongoing Payments*: Section 16-107.6(b) establishes that "The tariff shall also provide for additional uses of the smart inverter *that shall be separately compensated."* [Emphasis added] Because the "additional uses" include actions at the utility's sole option that take place over time, the ongoing revenue streams cannot be accurately predicted at the time of the rebate.

<u>Most States Have Not Set Firm Timelines for Implementing Distribution Value Compensation</u>

The investigations of distribution value that have taken place in other states have a more fluid character than is present in Illinois. Investigations of distribution planning and the development and validation of distribution value methods are not generally tied to any specific timeline, or DER penetration threshold. For instance, California's efforts towards developing granular locational benefits valuation methods commenced in August 2014.[3] While California has adopted several decisions associated with the initiative, approving demonstration projects, initial versions of valuation and planning tools, a framework for distribution investment deferral using DERs, and a grid modernization framework, it continues to revise its methods and has not established any firm timeline for the broad deployment of locational value compensation for DERs.[4] In its NEM 2.0 decision (D.16-01-044), the California PUC placed new net meteringcustomers on Time-of-Use tariffs but did not otherwise change the compensation structure from full retail rate net metering becaues they recognized that many of the benefits of net metered systems had not yet been fully realized.

Likewise, efforts in other states, such as New Hampshire, Maryland, Rhode Island, and Connecticut, remain in the relatively early stages of investigating protocols for establishing distribution value and overall "transformation" of the distribution system, without any firm timelines for completion or deployment.[5,6,7,8] Only one state, New York, has broadly deployed a DER framework reflecting a component for distribution value, and has done so only for community solar and large commercial customers on demand-based rate structures, and in an interim manner as the valuation methodology and tariff are more fully developed.[9] Mass market customers, defined as residential and small commercial customers (not on demand-based rates), were kept on the traditional NEM structure. Even so, New York's decision, compelled by a self-imposed timeline to take steps towards a value-based regime, recognized that much more data and

[3] California Public Utilities Commission ("CPUC"), Docket No. R.14-08-013. https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:R1408013

[4] *See* CPUC decisions in Docket No. R.14-08-013. D.17-02-007 (February 16, 2017), D. 17-09-026 (October 6, 2017), D.18-02-004 (February 15, 2018), and D.18-03-023 (March 26, 2018).

[5] New Hampshire Public Utilities Commission. Docket No. DE 15-576. https://puc.nh.gov/Regulatory/Docketbk/2016/16-576.html

[6] Maryland Public Service Commission. Public Conference 44 (PC 44). http://www.psc.state.md.us/search-results/?keyword=PC44&x.x=0&x.y=0&search=all&search=rulemaking

[7] Rhode Island Public Utilities Commission. Docket No. 4780. http://www.ripuc.org/eventsactions/docket/4780page.html

[8] Connecticut Public Utility Regulatory Authority. Docket No. 17-12-03. http://www.dpuc.state.ct.us/dockcurr.nsf/(Web+Main+View/All+Dockets)?OpenView&StartKey=17-12-03

[9] New York Public Service Commission ("NYPSC") Docket No. 15-E-0751. Order dated March 9, 2017.

work was necessary to refine the methodology to reflect the full value of these resources.[10] Furthermore, New York's tariff is using an interim 'Market Transition Credit' for community solar projects to account for the fact that the distribution and other values are insufficiently developed at this time as well as to allow for a smooth transition towards a value-based regime.

Illinois law by contrast establishes a "threshold date" based on the current 5% of peak load net metering penetration cap that triggers a move to a locational distribution value framework.[11,12] This potential "cliff" necessitates that Illinois proceed with both a sense of urgency in its own consideration of developing initial valuation methods in order to ensure that the system can be deployed by the time the 5% cap is hit – and an understanding that these methods will by their nature be incomplete.

The New York experience is instructive in this respect. Rather than assigning a zero distribution level value for DERs due to a lack of perfect data, it acknowledged that value does exist and adopted an interim system, including a 'Market Transition Credit' linked to the full retail rate. Illinois faces a similar choice in the future, and the Joint Solar Parties strongly recommend that it not let the perfect become the enemy of the good.

<u>The Statute Requires That Values Beyond Distribution Value and Smart Inverter Services Be Included</u>

As explained above, Section 16-107.6(b) and (e) do not simply refer to compensating DER for "distribution" value, but also value to "the grid." While "the grid" is not defined, the plain language meaning is far broader than simply the distribution system. The language of Section 16-107.6(e) in particular supports this view, where "the grid" and "distribution system" were used in adjacent sentences, suggesting that the terms were meant to address different values. The Joint Solar Parties fully support both identifying distribution-specific values and other values to "the grid."

Beyond the statutory language, there are several policy justifications for taking a broader view than simply the "distribution" value. Indeed, one reason why distributed energy resources are so cost effective is that they provide value that accrues at different levels of the electricity system. A solar PV system can help avoid a substation upgrade, but it also reduces energy demand and associated emissions. The substation that system helps avoid can't avoid greenhouse gas emissions just as a peaker plant can't relieve a local constraint on the distribution grid. DER advocates often refer to a comprehensive view of the DER value as considering the "full stack" of value.

The reasons for taking a broader view is multi-fold. First, the focus on distribution value renders any valuate incomplete unless other means of realizing system level values are present, such as the appropriate reflection of other value components in rates paid by customers and compensation paid to those customers for exports. Second, due to the higher degree of difficulty in developing

[10] NYPSC Matter No. 17-01276 (Value of DER Working Group). http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?Mattercaseno=17-01276

[11] 220 ILCS 5/16-107.6(a)

[12] The JSP note that during the March 1 workshop, several parties highlighted the differing approaches to the underlying methodology for calculating the NEM cap. Here, the JSP simply note the importance of this issue, the impact that it will have on how long the Commission has to come to a new tariff, and the need for resolution.

distribution level values, primarily due to insufficient data, some states have included distribution value only as a placeholder and not assigned it any specific value. For their purposes, this approach may be reasonable because those studies were designed as initial investigations, not for the specific purpose of establishing rates or compensation. As previously noted, Illinois' efforts take place in a different context because the value is to be used to determine rebates. Third, to our knowledge no state has attempted to fully capture the value of smart inverter services in there studies; again, typically leaving smart inverter services as a placeholder subject to future refinement. This further points to the need for Illinois to take an evolutionary approach to the tariff.

As previously discussed, Illinois law requires rebates to be designed to reflect distribution value as one of multiple values, and that separate compensation be provided for other services. Thus there is a separation between compensation for:

- Values to the grid that can be developed in advance (either through specific and currently available data or through proxy values); and
- Ongoing services that depend on *dispatch* of the smart inverter to address unpredictable need for services (e.g., voltage support, frequency regulation). Given that smart inverter functions, including but not limited to the volt-watt and frequency-watt modes, control the output of a DER (i.e., reducing availability to a customer), it is critical that the functions not be activated for control by a utility until mechanisms to provide commensurate compensation are in place.

B. What approaches from other states may fit or not fit in Illinois and why?

As discussed in our response to Question (A), Illinois does not have the luxury of indefinite time to develop an approach to assigning locational distribution value. The impending net metering cap creates a need for prompt action to develop at least a first-generation model that can be deployed by the threshold date.

Given both the statutory requirement for 5% and Illinois' longer term goals, the Joint Solar Parties recommend that the Commission follow a path that combines approaches from New York and California.

In the near term, we recommend the approach taken in New York whereby the Commission has taken an evolutionary approach to establishing location and time differentiated values, while fully acknowledging that while a step in the right direction, the valuation does not fully capture the benefits of DG. As a general approach to distribution value, the New York example is also instructive – it sets a system-wide distribution value and layers on top of that any location-specific benefits that can be identified.

In the longer term, we recommend the process employed in California through its Distribution Resource Planning proceeding as the most complete and comprehensive approach for several reasons. First, as in New York, California has recognized that its vision of transforming distribution planning and unlocking DER value is not a short-term initiative; it is a long-term evolution. Second, California's approach encompasses a series of essential components towards this end, addressing not only locational DER value, but also utility business models, distribution planning, grid modernization, and more general DER integration. Third, the processes it has employed, using open and transparent, formally-designated technical working groups with clearly defined objectives, timelines, and deliverables is consistent with developing the type of reliable, fact-based information needed to support regulatory determinations.[13]

C. What can be gleaned from original FEJA language or other key policies about rebates and valuation objectives and perspectives?

Several guiding principles for establishing valuation protocols and rebates within Illinois policy, as follows:

Long-Term Perspective for Valuation: See Foundational Goals and Principles at page 4 above.

Supporting Long-Term DER Growth: See Foundational Goals and Principles at page 4 above. In addition, Section 1(a)(1) of the FEJA contains several references to the overarching objectives of the law, among them, "the State should encourage the adoption and deployment of cost-effective distributed energy resource technologies and devices…encourage private investment…stimulate economic growth." This points to an intent to support sustained and consistent growth of DERs, as private investment and economic growth will not be achieved if the characteristics of the DER market are uncertain, unpredictable, or otherwise inconsistent. Long-term growth requires market stability, consistency, and predictability for providers and customers and retains a solid and predictable value proposition.

This objective is further supported by the design of the Adjustable Block program. Section 1-75(c)(1)(K) provides that the Adjustable Block program provide a stable platform in order to "enable the photovoltaic market to scale up and for renewable energy credit prices to adjust at a predictable rate over time." This likewise supports the premise that overall intent is to enable consistent long-term growth through the establishment of a predictable DER market.

Furthermore, see the importance of long-term DER growth to supporting Illinios' NextGrid vision, as described in the section 'Illinois Supports Expanding Distributed Generation' starting at page 2 above.

DER Value Must be All-Inclusive: The DER "value stack" consists of numerous components at different levels of the system, each if which is contributor to the whole. While Illinois law focuses on value to "the grid," including but not limited to the distribution system, in the context of rebates, assessing distribution system value should not subsume or push aside other grid values that do exist.

Inasmuch as a smart inverter is inextricably linked to the associated generation asset, the asset should be viewed holistically as a system. We believe that Section 16-107.6(b) and (e) require the Commission to consider a broader system perspective with respect to other beneficial uses to the extent that they are not adequately addressable through other means. Ultimately, the proper value of PV solar DERs must be analyzed from a holistic perspective and Commission should use every

[13] *See* for example, the materials associated with several defined working groups that support the Distribution Resource Planning process. https://drpwg.org/

means at its disposal to ensure that all benefits are properly considered and valued. Not doing so undermines the overarching intent of the FEJA to support cost-effective DER deployment.

D. What is the relationship to the valuations required by the Adjustable Block Program found in Sections 1-75(c)(1)(K) and (L) of the IPA Act?

The Adjustable Block Program is effectively a forward purchase of renewable energy credits ("RECs") at a price set at the time of purchase with a price signal related to demand. While the details of the Adjustable Block pricing model are substantially different than the value of DG calculations, the essential feature that both are intended to provide a known revenue stream based on a signal provided (and locked in) at the time of application.

That said, the Adjustable Block program is essentially monetization of one revenue stream, the REC. Put another way, the incentive provided by the program represents only RPS compliance value to the exclusion of other values. As previously described, the Adjustable Block Program endeavors support the scale up of solar photovoltaics, through the use of predictable and transparent pricing. The basic structure of the Adjustable Block pricing model illustrates this effort. The Adjustable Block Program, however, was not created within a conversation of how to fully value the environmental and societal benefits DERs bring to the grid. This limitation may need to be addressed in the DER valuation proceeding.

From the perspective of long-term predictability, while the concepts may be similar a distinction must be made between what is addressed in the Adjustable Block Program relative to what is required for distribution value determinations and rebates. The Adjustable Block program, as an instrument of the RPS requires that REC contracts have a term of at least 15 years.[14] As a definition of "long-term", 15 years must be viewed in the context of the RPS which does not contain incremental additional requirements beyond 2025. Moreover, RECs are instruments for which the value is driven by numerous factors, in particular changing policy.

While the Adjustable Block Program is a reflection of policy, it should not be taken to confine the meaning of "long-term" to 15 years when considering the long-term value of DERs to the distribution system. Fifteen years was hard-coded into Sections 1-75(c)(1)(K) and (L) of the IPA Act, but a statutory time horizon is conspicuously absent in Section 16-107.6(b) and (e) of the Public Utilities Act. Furthermore, the Joint Solar Parties note that in creating the Adjustable Block pricing model, where the IPA attempted to model the non-REC costs and revenues of PV solar DERs, the IPA assumed a useful life of 25 years for energy and other revenues. As DERs contribute distribution value throughout their respective lifetimes, the assessment of that value should not be artificially confined to a shorter period. A 25-30 year time horizon is a more reasonable time frame for which to assess distribution value.

E. What categories of data are or are not available that will influence value calculations?

Generally speaking, utilities in Illinois currently use embedded cost of service studies ("ECOSS") rather than MCOSSs in ratemaking proceedings. (*See, e.g.* ICC Docket No. 01-0423, Interim Order dated April 1, 2002 at 124.) The lack of reliable marginal cost data is a clear data gap at present:

[14] 20 ILCS 3855/1-75(c)(1)(L)

marginal costs, whether system-wide or localized, are the widely accepted means for calculating the value of avoided or deferred investments.[15] It is not entirely clear whether existing data sources could serve as a temporary substitute for marginal cost data. Ameren, ComEd, and MidAmerican do not currently submit long-term distribution planning information to outside entities for evaluation, so we do not know precisely what information they possess that could be useful. The long-term valuation of distribution assets underlying the formula rate approach used by Ameren and Commonwealth Edison may provide some insights. However, we emphasize that determining the usefulness of this data requires a much more thorough review, analysis and overall vetting. Also, while the utility collects SCADA data regarding reliability, there may be reasons to look at more granular information to determine projected reliability benefits. Furthermore, these data sources are typically based on a short run horizon rather than the long-run horizon needed for properly valuing distributed generation resources.

Apart from that, it is impossible to know what other gaps exist at this early stage of the investigation. Data needs and availability, now and in the future, have been the subject of months and years of working group meetings among industry experts. This type of process is essential, insofar as it is not only a question of identifying what data is necessary, the process must encompass the development of solutions that fit available data, methods of obtaining data that is not presently available, and how ongoing improvements in distribution architecture as well as regulatory refinements via NextGrid will support the assembly of additional data for future refinements. The availability of data and future refinements is exactly why taking an evolution approach to DER valuation is recommended.

F. What are process suggestions or considerations for arriving at DG rebates?

We recommend that the Commission consider the following hierarchy of issues for translating the statutory language into a practical tariff:

- **Consistency with Illinois Law:** The approach must be consistent with Illinois law. This requires both an up-front rebate and an ongoing payment for services.
- **Sustainable, Long-Term Market Development:** Within the confines of Illinois law, the Commission should use its discretion where available to provide reliable, long-term price signals for developers of different types of DERs. Those signals should be created, so the interests of the developers—and their customer(s)—align with the utility's distribution planning needs.
- **Implementable on Statutory Timeline:** While long-term viability is critically important, it is also important not to harm the market in crucial early years by having a failed or delayed signal. The Commission should make explicit to all parties that while market development is a primary policy concern, and it will take steps to ensure that approved formula pursuant to Section 16-107.6(e) is memorialized in utility tariff before the 5% cap is hit so it can become effective immediately upon the cap being triggered.

[15] *See* for example, IREC. A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation. http://www.irecusa.org/wp-content/uploads/2013/10/IREC_Rabago_Regulators-Guidebook-to-Assessing-Benefits-and-Costs-of-DSG.pdf and the Solar Energy Industries Association listing of solar cost-benefit studies. https://www.seia.org/initiatives/solar-cost-benefit-studies

- **Evolution:** While it is important for the early days of the program to be implemented and implementable when the 5% cap is triggered for each utility, the Commission should treat these tariffs as constantly evolving (for new systems) as utility distribution grids (and related services), distribution grid planning, utility business models, and distributed energy technologies evolve. This approach should also take into consideration differing abilities of end-users or customers of DERs to respond to these tariffs as well as how that ability may evolve over time as technology and markets evolve. This should apply to both to up-front payments as well as the "separately compensated" periodic payments.

With respect to the specific process, our overarching recommendation is that developing methods of determining compensation and rebate amounts proceed largely through working groups consisting of stakeholder experts, utility personnel, and a facilitator (e.g., Commission staff or an outside, independent group working on behalf of the Commission). This working group or groups must have a formal mandate and clearly defined objectives and timelines.

At a high level, our expectation is that the working group(s) would produce reports on a set timeline consisting of proposals for different aspects of the valuation regime that can be distributed for broader stakeholder comment. The national lab delivereable discussed at the March 1 workshop could be the starting point of discussion for these working group(s). The reports themselves would discuss the reasoning behind the proposal, potential alternatives, and level of stakeholder consensus on different aspects to the extent that some elements cannot be agreed upon. After comments are received, the Commission would, through a formal proceeding, make its decision on what, if any, aspects to adopt, and provide direction for any future work it believes is required.

Given the degree of urgency establishing a clear path to the development of at least a first-generation valuation methodology, we recommend that working groups be convened as soon as possible, with the docketed proceeding potentially starting before the 3% threshold is met. To ensure the process stays on track, interim milestones should be set with periodic progress updates given to the Commission. Among the highest priority topics that must be addressed are:

- Assigning the relative level of priority given to developing values to the suite of grid and distribution grid benefits that can be provided by DERs.
- Generating a common understanding of currently available data.
- Producing a work plan that is can result in the adoption of at least an interim rebate determination methodology within 18 months.
- Producing a contingency work plan designed for implementation in no greater than 6 months for use in the event it becomes necessary due to the approach of the net metering cap.

G. Which value elements are most important for Illinois?

This is a critical question that is not possible to fully answer at this time. Distribution deferral value and marginal reliability value are likely to be a large component of distribution service value. Upgrades to the distribution system as part of the interconnection process and their impact on deferred/avoided upgrades are another. We recommend that developing a value prioritization list reflective of both relatively magnitude and data availability be among the first tasks undertaken by technical working groups.

H. What elements should be considered in differentiating DG value by location?

Generally, we think that the technical aspects of this question are most suitable for detailed consideration in a working group format. However, there are a series of general principles that should be considered in the context of implementation, as follows:

- **Transparency**: Information on locational differentiation must be made available in a manner that is easily accessible, and can be processed by providers and customers. For instance, if a given value is specific to an area served by a specific substation, it must be possible to reliably identify customers served by that substation through using information available to both providers and customers. Furthermore, if a local area is targeted for a certain amount of DERs to meet a need, the status of enrollment must be updated in as close as real time as possible.
- **Simplicity**: Granularity must be balanced with a need to make the system manageable for providers and customers. In practice, this means that granularity should not be established to a resolution not supported by available tools, and differentiation should likely target a relatively small number of particularly high value locations.
- **Consistency**: The duration of location specific values (e.g., the time between updates) must be long enough to allow providers to adapt to target those areas.
- **Predictability**: Location-specific values must be fixed over the long-term for customers that enroll at a given value, in recognition that customers require this predictability and that as long-lived assets, DERs are providing long-term value consistent with identified current and future needs.

III. DG Valuation Questions

On or around March 21st a series of additional questions addressing technical DER valuation were posted on the Commission's DER Valuation website. At the outset we wish to state that these questions are an excellent starting point for establishing what needs to be answered as part of this process. While we appreciate the opportunity to respond and the ambition of promptly seeking answers to these questions, we are concerned that the timeline is too short for stakeholders to formulate complete responses, and in some cases it is not entirely clear to us what information is actually being requested. Our brief responses below should be considered preliminary, as we believe there are numerous nuances that require more work to adequately sort through.

Towards this end, we recommend that the work of California's Locational Net Benefits Analysis ("LNBA") working group be consulted. The LNBA working group has issued two reports to date on locational benefits analysis. The first report formed the basis for the CPUC's adoption of the initial parameters and capabilities of the LNBA tool.[16] The second report addresses refinements to the tool to add greater granularity to locational values for system-level benefits, locational transmission benefits, and distribution benefits. The reports themselves and related materials, which address consensus and non-consensus recommendations and stakeholder viewpoints, can

[16] CPUC D.17-09-026. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M196/K747/196747754.PDF

provide a solid foundation for Illinois to work from.[17] Beyond the valuation methodologies, they illustrate how certain aspects of the analysis were prioritized, the functionality of a tool showing LNBA results, the evolution of the analysis, and the process employed.

Process-wise, we have recommended that a working group format is the most effective way to develop information and valuation proposals. Additionally, we recommend that stakeholders be given an opportunity to submit reply comments to any comments received in response to the present set of questions, with at least a three week response window from the time the permission to reply is granted.

A. Should the calculated values be limited to the value of distributed energy systems to the distribution network? If not, what other identifiable benefits of distributed energy systems should be included in the values calculated pursuant to Section 16-107.6?

As discussed more fully in the section '<u>Illinois' Use of a Rebate is Unique But Manageable if Done Correctly'</u> at page 6 above, Illinois statute requires that the DG rebate include both benefits 'to the grid' and benefits to the 'distribution grid'.

In order to support the state's goals and meet its statutory requirements, it is critical to consider DER value at all levels of the system. This value may be reflected in compensation for DERs in different ways. For instance, one source of revenue is through net metering credits. However, this only captures a limited universe of value streams.

It is critical that the full capabilities of a DER system be fully reflected in the associated compensation it receives, whether through the DG tariff or another mechanism. Traditionally recognized value categories include:

1. Avoided capital costs for distribution and transmission upgrades
2. Avoided distribution operations and maintenance expenses
3. Avoided energy
4. Avoided generation capacity
5. Avoided ancillary services
6. Avoided transmission and distribution system losses
7. Avoided RPS integration costs
8. Avoided environmental impacts, including but not limited to emissions of greenhouse gases and criteria air pollutants.

B. What are the types of values that distributed energy systems provide to the distribution network?

The general categories of values that DERs can provide to the distribution system are typically categorized as:

[17] The full working group reports and materials are available at: https://drpwg.org/sample-page/drp/

- Avoided distribution capacity costs
- Distribution voltage/power quality support
- Reliability (non-capacity related) and resiliency

In addition to these broad categories, participants in California's LNBA working group have identified additional potential values including:

- Reduced distribution maintenance
- Extended equipment lifetimes
- Enablement of reduced sizing in equipment replacements
- Enhanced situational awareness & grid visibility

As discussed in previous sections, benefits to the distribution system are not the only benefits to be incorporated into this tariff.

C. How does each type of value that a distributed energy systems provide to the distribution network (identified in part (b)) vary geographically?

As a general matter, all of the categories likely display some level of geographic variation. We do not possess the information to describe how exactly each value varies geographically on the systems of Illinois' electric utilities, such as to what degree a given value may vary on individual circuits or at specific locations on a circuit. However, with respect to geographic variations we make two initial observations:

- Variability can be a matter of perspective and scale, insofar as small variations may exist down to a highly local level while by and large, the values remain similar within a much larger area.
- The fact that variability exists on the local level does not dictate that the use of system-wide estimates is inappropriate, in particular where a lack of granular data prevents more precise estimates from being made.
- Long-time horizons mean that even if there are not near-term identified locational needs, a project is likely to avoid investments over its life and that value may best be captured through a system wide average rather than an extrapolation of a locationally-specific value.

Defining parameters for evaluating local variability, including data needs, availability, and appropriate scales, should be discussed in the working group process we recommend.

D. How does each type of value that a distributed energy systems provide to the distribution network (identified in part (b)) [vary] across time?

It is not clear to us whether this question is intended to refer to variability from the perspective of: (1) how needs may arise consistently during specific periods (e.g., high loads during peak periods) or, (2) the time horizon associated with how needs are identified via planning processes. Both perspectives are important for determining how values are identified. The first is largely a question of the capabilities of a given generating facility to respond in a manner that reflects the temporal need for a given service (e.g., storage dispatch, control of a smart inverter).

The second is more fundamental with respect to determining long-term value. With respect to this type of variability, once a need is identified and planned for (e.g., targeted for investment), it ceases to be "variable" because decisions of how to meet that need must be made. Those decisions, whether they involve investments in traditional infrastructure or DERs, fix the value of an asset based on the available information at the time they are made. Therefore, that value exists for the duration of the life of the asset as it provides the associated service.

Unplanned needs also exist, either because they arise as a result of changing conditions in the short-term (e.g., unexpected load growth), or because they exist beyond the time horizon of typical planning. Either situation presents the potential for DERs to generate value, but that value may be difficult to identify. This issue merits further discussion in the working group process we recommend.

E. How does each type of value that a distributed energy systems provide to the distribution network (identified in part (b)) depend upon the distributed energy system technology?

At a basic level, a DER may be dispatchable or non-dispatchable. A dispatchable DER includes one equipped with energy storage, or to a lesser degree, one controlled by a smart inverter. Dispatchable DERs offer greater value at all levels because they can respond to specific conditions, but that does not mean that non-dispatchable DERs are not capable of providing value. A non-dispatchable DER can provide value when its characteristics of operation align with system needs. For instance, a distribution feeder that has consistent day-time peaks benefits from DERs such as solar that reduce load during those typical peak periods.

Energy storage enhances a DER both from the perspective of dispatchability and range of operation. The value of an energy storage DER may vary based on its maximum output and storage capacity. Smart inverters enhance the capabilities of a DER in a more limited way because they can only modify the output within the range that the DER would normally operate, though communication capabilities can also contribute to increased grid visibility irrespective of whether the output of a DER is modified. We recommend that the Commission review the previously referenced Californian LNBA working group materials and the California Smart Inverter Working Group (SIWG) reports on smart inverter functions for a more detailed assessment of smart inverter capabilities.[18]

F. What information is necessary to calculate each type of value and is such information available?

Generalized marginal cost data is a critical for determining value at a system-wide or regional level, but we do not know whether, and at what resolution and time horizon, such information is currently available. Consequently, it is not possible for us to completely identify the necessary data and its availability for all potential distribution values at this early point in the process. Data needs and availability require further discussion as the process moves forward.

[18] California Smart Inverter Working Group. http://www.energy.ca.gov/electricity_analysis/rule21/

From the perspective of specific needs identified in the distribution planning process, the ultimate benchmark is the specific cost of a project. However, we lack visibility into the assumptions underlying identified needs, as well as the nature, magnitude, and timing of those needs. A more transparent distribution planning process, with opportunities for non-utility stakeholders to view and understand planning procedures, is necessary.

G. How can each type of value that a distributed energy system provides to the grid (i.e., the systems actual performance) be evaluated?

At a high level the measurement of DER performance is a function of output or response as aligned with a need. While the simple answer to this question is that appropriate metering should be employed, it is difficult to specify what type of measurement is necessary (e.g., interval, communication) without first defining the nature of a grid service or need. As a general rule, the level of granularity of performance measurement should be balanced against the cost of achieving that level of granularity in the context of an individual grid service. Also, as discussed previously in our comments, the Commission should take an evolutionary approach to these tariffs and valuation approaches while also incorporating policy goals such as market development and financability of DER projects.

H. If you identified the value of distributed energy systems benefits other than benefits to the distribution network, please address questions (b) - (g) with respect to such other identifiable benefits.

Due to the short time frame for submitting these comments we have not been able to assemble a response to this question other than to highlight that Illinois law requires that this tariff address benefits not only to the distribution system but also to the grid more generally. We strongly recommend that any recommendations made on this topic not be made until stakeholders have had additional opportunities to address it via written comments and working group proceedings.

I. Considering available information, how should distributed generation energy resource benefits be calculated?

In our estimation, at this time available information is minimal. The first step in moving this initiative forward should be the establishment of guiding principles and a well-defined process for developing the necessary information and ultimately a methodology proposal in a transparent manner. In light of this we make the following high-level recommendations:

- Benefits should be calculated using a time horizon consistent with the useful life of DERs.
- The scope of benefits calculations should consider the full suite of DER benefits in order to develop a complete picture and allow the evaluation of whether DER customers are being compensated accordingly through different mechanisms.
- The methodology should be arrived at and vetted through a transparent working group process, with any proposals subject to stakeholder comment before adoption.
- The determination of values should employ a phased approach that allows first-generation methods to be developed in the near term, while allowing for refinement of those methods over time.

IV. Appendices

For the information of Commission Staff, PNNL, and other stakeholders, we have attached the following documents for reference:

SEIA's 5-Part Grid Modernization Whitepaper Series:

Part 1: How California & New York are Building Grids that Encourage the Growth of Distributed Energy Resources

Part 2: Improving Distribution System Planning to Incorporate Distributed Energy Resources

Part 3: Hosting Capacity: Using Increased Transparency of Grid Constraints to Accelerate Interconnection Processes

Part 4: Getting More Granular: How Value of Location and Time May Change Compensation for Distributed Energy Resources

Part 5 (Forthcoming): Distributed Energy Resources as Distribution Grid Infrastructure: Opportunities Beyond Wire

Sustaining Solar Beyond Net Metering: How Customer Owned Solar Compensation Can Evolve in Support of Decarbonizing California

We appreciate the opportunity to provide comments in this informal stakeholder proceeding. and look forward to continuing to work with the Commission Staff and other stakeholders to develop a Value of DG tariff that works for all of Illinois' goals in both the short term and the long term.

Sincerely,

Sean Gallagher	Lesley McCain	Brandon Smithwood
VP, State Affairs	Executive Director	Policy Director
Solar Energy Industries Association	Illinois Solar Energy Association	Coalition for Community Solar Access

SUSTAINING SOLAR BEYOND NET METERING

How Customer Owned Solar Compensation Can Evolve in Support of Decarbonizing California

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GRIDWORKS

SUSTAINING SOLAR BEYOND NET METERING

How Customer Owned Solar Compensation Can Evolve in Support of Decarbonizing California

JANUARY 2018

INTRODUCTION

California has committed to rapid decarbonization of its power sector. The state is pursuing that objective through a wide range of policy solutions, one of which is net metering, an incentive encouraging customer adoption of renewable distributed generation, especially solar.[1] To date net metering has supported the adoption of solar by over 725,000 California customers, totaling nearly 6 GW of installed capacity.[2] These adoptions have contributed to reductions in greenhouse gas emissions from the power sector and local job creation. Net metering has been a success by many of California's key measures.

Looking forward, California's path to decarbonization assumes increased reliance on renewable energy, including estimates of up to 16 GW of behind the meter solar by 2030.[3] Achieving these targets would require accelerated customer adoption of solar. But as analyses of California's electric system have demonstrated, continued growth in generation during day-time solar peak periods creates two challenges: excess generation at the system-level and grid constraints at the distribution-level. Excess generation at the system-level has been demonstrated by increasing negative prices and resource curtailment, including of renewable generation.[4] Distribution-level grid impacts have been demonstrated through analysis of distribution system hosting capacity showing limited capacity to absorb mid-day solar production in areas of high-solar penetration.[5]

At their core, these challenges are the manifestations of

1 Use of the term "solar" throughout this paper implies behind the meter, customer owned solar generation.

2 http://www.californiadgstats.ca.gov/, October 23, 2017.

3 California Public Utilities Commission, see Administrative Law Judge's Ruling Seeking Comment on Proposed Reference System Plan and Related Commission Policy Actions, Attachment A: Proposed Reference System Plan. September 18, 2017. (http://cpuc.ca.gov/irp/proposedrsp/.)

4 "Q1 2017 Report on Market Issues and Performance." California ISO. July 10, 2017; "California wholesale electric prices are higher at the beginning and end of the day." EIA, 2017.

5 California Investor Owned Utility Reports on Integration Capacity Analysis for Distribution Resource Planning. December, 2016.

CONTENTS

misaligned power supply and demand. Going forward, rather than spread like seeds in the wind, solar energy needs to be planted at locations advantageous to the grid and needs to produce simultaneous with demand, or stored until there is demand. Solar alone will not suffice; it needs to be locationally targeted and co-located with storage. [6]

Meanwhile, California policy-makers have continued to push for differentiation of incentives for solar by location, ensuring grid costs are fairly recovered, and enabling customer choice. A clear need for balancing these objectives with the State's decarbonization imperative exists.

This paper reexamines net metering, asking how to build on its success to further California's decarbonization, account for location value, fairly recover grid costs, and enable customer choice. Evaluating alternative policies and applying consistent criteria reflective of California's principles this analysis identifies advantages and disadvantages to net metering and variations thereof. Based on this analysis we conclude California can sustain solar beyond net metering. We recommend California policy-makers move expeditiously to transition the state's solar compensation framework toward a net billing structure with locationally differentiated prices paid for exports. As detailed further in this paper, the transition may be eased in several ways and informed by data and insight gained through evaluation of current net metering policies, helping to sustain growth in customer adoption and achieve forecasted levels of solar.

DEFINING NET METERING AND VARIATIONS

KEY CONCEPTS UNDERPINNING NET METERING

The following section advances a standardized taxonomy and framework for net metering and its variations.

California Public Utilities Commission (CPUC) Decision (D.) 16-01-044 provides the following explanation of how net metering (NEM) works in California:

"Under NEM, customer-generators offset their charges for any consumption of electricity provided directly by their renewable energy facilities and receive a financial credit for power generated by their on-site systems that is fed back into the power grid for use by other utility customers over the course of a billing cycle. The credits are valued at the "same price per kilowatt hour" (kWh) that customers would otherwise be charged for electricity consumed. Net credits created in one billing period carry forward to offset customer-generators' subsequent electricity bills. At the end of every year that a customer-generator has been on the NEM tariff, the credits and charges accrued over the previous 12-month billing period are "trued-up." A customer producing power in excess of its on-site load over the 12-month period may be eligible for "net surplus compensation" under certain conditions."[7]

6 Decision 17-01-006, p. 4. California Public Utilities Commission; California PATHWAYS: GHG Scenario Results, Slide 14. April, 2015.

7 D.16-01-044, Page 13. CPUC.

Within this explanation are both physical (e.g., consumption) and financial (e.g., credit) concepts.

FIGURE 1

ILLUSTRATING PHYSICAL NET METERING CONCEPTS

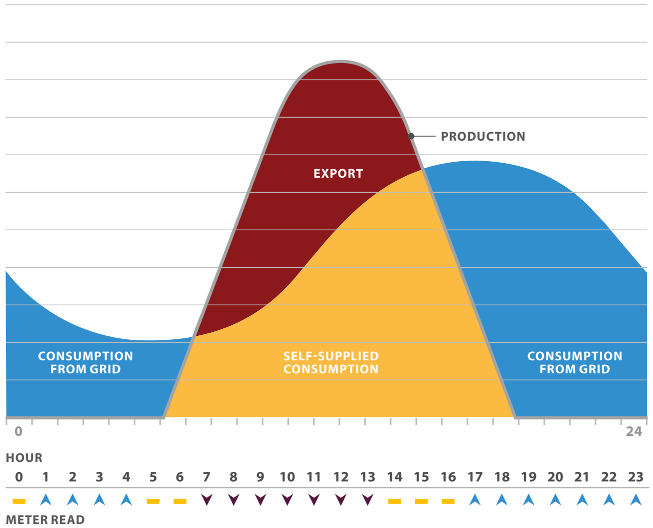


FIGURE 2

ILLUSTRATING FINANCIAL NET METERING CONCEPTS

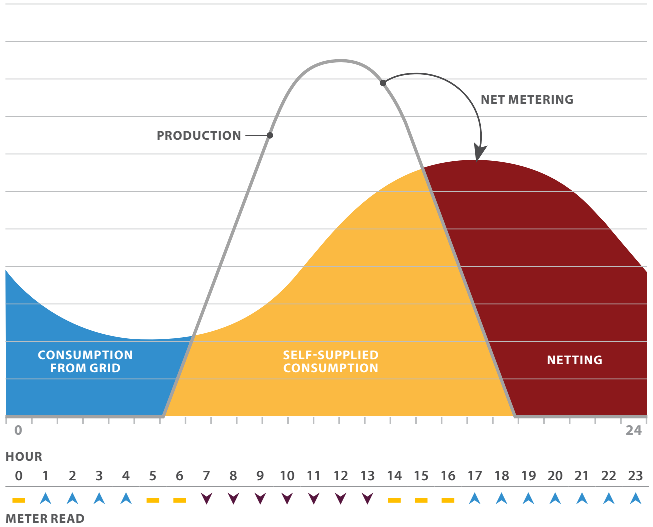


Figure 1 illustrates the physical net metering concepts, consumption and production of a customer generator over a single day. During different times of the day, production and consumption may or may not overlap, delineating the concepts of consumption from the grid, exports to the grid when on-site production exceeds consumption, and self-supplied consumption (self-supply). Self-supply, as illustrated here by the figure's yellow area, manifests as reduced consumption from the grid. These dynamics are manifest in the values recorded by the customer's meter, with values rising when consumption from the grid increases, flat when production and consumption are equal, and falling when exports increase.

Net metering overlays certain financial concepts on these physical ones to compensate customer generation. Most prominent is the concept of netting, as illustrated in Figure 2. Netting is offsetting a financial charge for consumption with a financial credit for production. As illustrated above, that offset can be physical and simultaneous as with self-supply (yellow area). Alternatively, netting can be non-simultaneous whereby credits for exports (maroon area) are carried forward to offset subsequent charges which would otherwise result from consumption from the grid (blue area). Key to understanding net metering is this delinking of the physical and financial: netting enables a customer to financially self-supply while consuming from the grid — while the meter read increases, the consumption charge does not.

Netting can be allowed at different intervals ranging from instantaneous to annual. Accounting for netting relies on reading a meter, so in practice the most granular netting interval for determining simultaneous self-supply is the most granular meter interval – how often the meter records a customer's consumption. In California, this is currently hourly for residential customers and 15-minute for commercial. The netting interval may have a substantial impact on the value of a solar investment for the adopting customer. Traditionally longer netting intervals are more advantageous for the adopting customer as seasonal variation in production and consumption allow for maximum netting. Customers with shorter netting-intervals, such as commercial customers, receive less benefit from netting.

CORE STRUCTURES | NET METERING, NET BILLING AND BUY ALL, SELL ALL

This analysis refers to alternatives to net metering as different core structures. The critical difference between core structures is what portion of production may offset charges for consumption, effectively compensating the customer for production at the rate she would otherwise be charged for consumption.

As summarized, a net metering compensation structure allows charges for consumption to be offset enabling compensation of all production at the consumption charge (netting). Two alternatives to net metering alter this approach to netting. The first alternative core structure is **net billing**, which awards credit to exports at a specified price which is different than the consumption charge. A net billing construct preserves self-supply, compensating the customer for the self-supplied portion of her production at the consumption charge. Credits awarded to exports are at a price other than the grid consumption charge, which may count against subsequent charges or be monetized. The second alternative core structure is buy all, **sell all (BASA)**, which relies on a dual-meter system to meter all production and all consumption separately. All production receives compensation at a price other than the consumption charge. Under a BASA framework, self-supply does not offset the customer's charges for consumption.

This formulation of core structures creates an important distinction between a compensation structure and the underlying rate design. In practice the two are intertwined, but the focus of this evaluation is how the overlaying compensation structure may be adapted. The limited exceptions to this approach are noted below.

Compensation of customer generation may be accomplished through adapting one of these three concepts to meet the goals of the jurisdiction. The following section describes the most accessible adaptations that can be made, constituting a tool kit available to policy makers.

THE TOOL KIT | CONSUMPTION CHARGES, EXPORT PRICES, ANCHORS AND ADDERS

Consumption charges, export prices, anchors and adders are tools that can be used to adapt one of the core structures to accomplish objectives.

The "consumption charge" is a charge to a customer for power consumed within a designated period. These charges in California today are largely volumetric for residential and small commercial customers. Furthermore, residential charges are tiered, such that the charges for consumption increase as consumption increases. A primary tool available to the policy maker is amending the consumption charge required of a customer generator. For example, in D.16-01-044 the CPUC required new customer generators to enroll in time of use (TOU) rates and pay certain non-bypassable charges on power exported to the grid in each metered interval (see dark blue section of Figure 1).

"Export prices," as used in this paper, is a term deliberately distinct from retail rate or consumption charges that instead refers to the compensation level paid to the customer for exports. BASA treats all production as an export. Net billing pays a price to exports (only), while compensating self-supply at the consumption charge. Under these constructs policy makers can adapt export prices to suit objectives. Export prices could be based on many factors, including where the resource is located, when the resource is delivering energy to the grid, and the market conditions that exist when the export occurs.

Beyond consumption charges and export prices, anchors and adders can be applied to achieve different objectives. The term "anchor" as used in this paper refers to a change to the customer compensation framework which reduces the customer's economic return to align their interest with other objectives, such as encouraging generation at times and locations of greatest value to the grid. An "adder" is the opposite, contributing to the customer's economic return in pursuit of additional advantage.

Anchors may include a fixed charge, minimum bill, standby rate, tolling fee for distribution of exported energy, demand charge, interconnection charge, prohibition on exports, or shorter netting intervals. Adders may include grid service payments, locational adders, environmental value, renewable energy credits, market transition credits, time of delivery adders, peak event-based adders or longer netting intervals. Complete definitions and references supporting these anchors and adders are provided in Appendix A.[8]

In sum, policy makers have a wide range of options between three underlying core structures, and the application of customer charges, export prices, anchors and adders. Appendix B illustrates how certain states and California stakeholders have applied these tools. Looking forward to California's future, the following section identifies a range of plausible options for consideration.

POTENTIAL COMPENSATION STRUCTURES FOR CALIFORNIA

In D.16-01-044 the CPUC asked staff and stakeholders to "explore compensation structures for customer-sited DG other than NEM, including analysis and design of potential optional or pilot tariffs, with a view to considering at least an export compensation rate that takes into account locational and time-differentiated values of customer-sited DG."[9]
In the spirit of this call to action, the following potential compensation structures for California were identified through stakeholder engagement and research on how other states are compensating customer generation. These options do not represent an exhaustive list of possible compensation frameworks, rather a reasonable cross-section reflecting ongoing trends in California's energy policy landscape. This section introduces those options; a later section evaluates them.

Several new concepts are included within these options. They are introduced in the context of the following explanations of each option.

TABLE 1

	OPTION NAME	SELF-SUPPLY	EXPORT PRICE	ADDER/ANCHOR
1	NEM 2.0	Y	Retail Rate	Selected Non-bypassable charges; Time of Use Rate[10]
2	Net Billing	Y	Locational Value	Transferrable Credit; Transition Credit; Opt-in Grid Services
3	Net Billing + Grid Services	Y	Market Price	Transferrable Credit; Managed Demand Charge
4	Buy All, Sell All	N	Locational Value	Transferrable Credit; Transition Credit
5	BASA + Grid Services	N	Market Price	Transferrable Credit

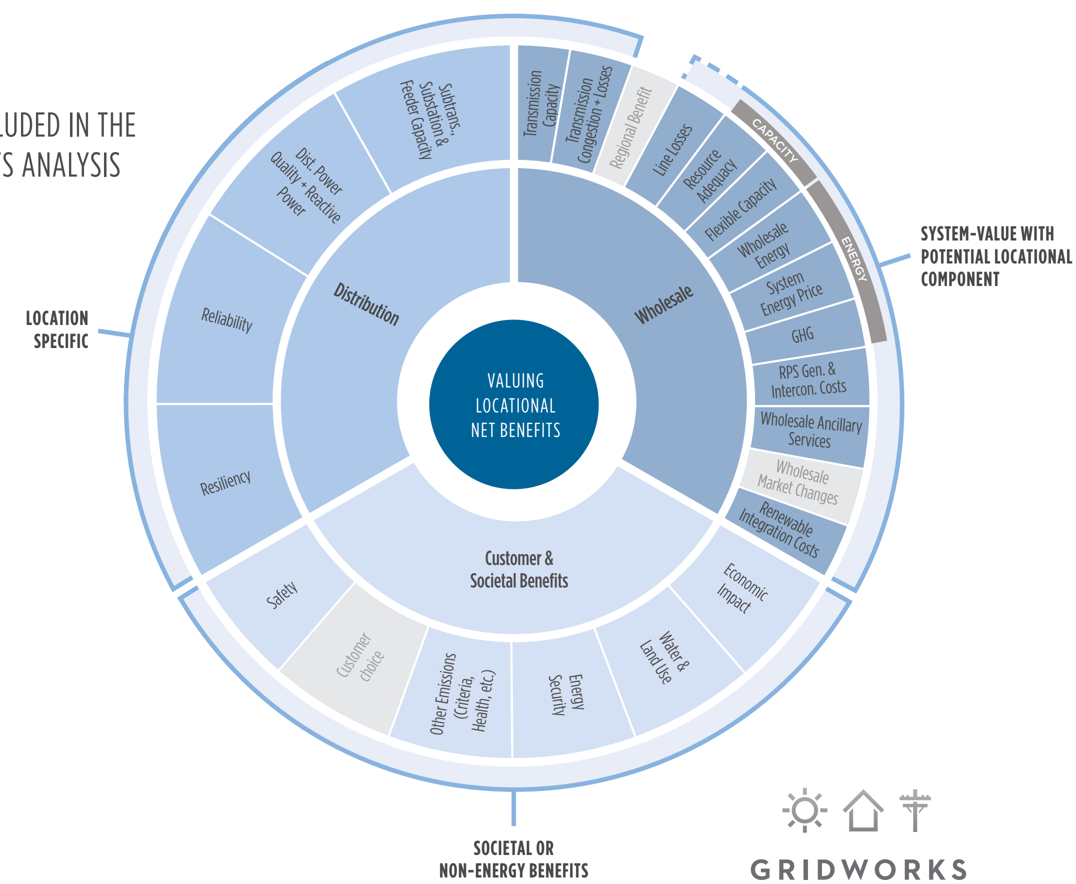
8 Appendix A and B are posted at www.gridworks.org
9 D.16-01-044, p. 103. CPUC.

10 To allow for comparison, the following assumptions are held constant throughout these options: current CPUC policy on minimum bill charges, non-bypassable charges, TOU rates, netting and true up intervals remain unchanged unless explicitly noted; no unidentified anchors or adders incremental to those identified here are applied.

FIGURE 3

VALUE COMPONENTS INCLUDED IN THE LOCATIONAL NET BENEFITS ANALYSIS

Analyzed
Not analyzed



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OPTION 1 | NEM 2.0

This option reflects the status quo. The only exception to current practice we contemplate is the possibility of further evolution of TOU rates to allow those rates to more specifically reflect grid conditions, including a) greater peak-to-off-peak rate differentials, b) greater locational rate specificity, and c) further shifts in TOU periods on daily or seasonal basis.

OPTION 2 | NET BILLING

This option reflects a net billing core structure with exports compensated at the resource's Locational Value, an export price informed by the **Locational Net Benefits Analysis (LNBA)**.[11] The LNBA is a methodology being developed under the supervision of the CPUC which differentiates the value of customer generation by location, as illustrated in Figure 3.

Depending on how the administratively set locational values are determined, this export price could differ between customers. To enable a predictable return for the investing customer, it is assumed that the export price paid to an enrolling customer would be fixed for a practical duration and variable following that duration, updated periodically, based on refreshed LNBAs. It is assumed the valuation is updated annually to allow newly enrolling customers to be compensated at refreshed pricing.

Two additional features of this option may be considered to support customer adoption. First, would be the inclusion of a Market Transition Credit.

MARKET TRANSITION CREDIT | Awarding additional temporary compensation to a customer generator during a defined period (e.g., 5 years, indexed to total customer adoption, up to percent of system peak) that ramps down over time but recognizes the importance of continued clean energy development.

There are many ways such a credit could be structured. Here we envision a "step- down" Market Transition Credit, whereby an adder to the LNBA-based export price tapers down to zero out over time. The scale and pace of the step-down could be benchmarked to installed capacity, like early California Solar Initiative rebate designs.

TRANSFERRABLE CREDIT | Allowing credit earned by a customer generator for exports to the grid to be transferred to any other customer at the discretion of the customer generator.

11 For additional background on the LNBA, see for example, Southern California Edison Compnay's Demonstration Project B Final Report at https://drpwg.org.

Because the net billing framework suggested here compensates exports at a price reflecting their Locational Value, credits earned for these exports could be transferred to any other customer. The impact of transferrable credits would depend on whether the generator must be "sized-to-load," as is the case under NEM 2.0. We envision that requirement being lifted.

Finally, we contemplate the exports may also be eligible for participation in grid services on an opt-in basis.

GRID SERVICES | Market-based compensation for DER providing energy, capacity, voltage support, frequency regulation and resiliency pursuant to an identified grid need. Compensation may be at wholesale or distribution level.[12]

Compensation to customers opting into grid services would be an alternative to administratively determined export prices, such that the customer chooses one or the other, but is not eligible for both.

OPTION 3 | NET BILLING + GRID SERVICES

This option reflects a net billing core structure with exports compensated at market prices based on their participation in grid services markets. Whereas in Option 2 the customer would be defaulted onto the administratively determined LNBA-informed export price with the option to opt-in to grid services markets, Option 3 would default the customer's exports into grid services markets. It is assumed that aggregators will serve as the customer's agent in participating in such markets, but individual customer participation is not precluded.

MARKET PRICE | Prices paid for grid services may be market-based resulting from competitive solicitations, participation in organized wholesale markets or other transaction platforms. Distinct from other contemplated pricing mechanisms which result from administrative value determinations (e.g., locational value, retail rate).

An additional feature of this option would be **a managed demand charge**.

12 Wholesale Grid Services may include: energy, regulation up, regulation down, spinning reserve, and non-spinning reserve. Detailed service definitions at http://www.caiso.com/participate/Pages/MarketProducts/Default.aspx. In addition DER aggregations may be eligible to provide system, local or flexible resource adequacy capacity (RA). Designation of a DER/DERA for RA entails must-offer obligations (MOO) under the ISO tariff to participate in the markets for these wholesale grid services. Distribution Grid Services may include: energy (up/down), capacity (up/down), and voltage/volt ampere reactive (VAR, up/down). Distribution service definitions are detailed in CPUC D. 16-12-036.

MANAGED DEMAND CHARGE | A rate design feature in which a customer receives a charge based on their maximum electric capacity usage during a defined interval in which capacity to serve customers is relatively scarce. Customers can reduce or avoid the charge through reduction of maximum usage through generation, changes in consumption, or use of storage technology to shift load.

This feature is highlighted because it may provide a meaningful opportunity for a utility to recover costs for grid services unless the need for those services is reduced by a customer's change in consumption or adoption of a storage technology. Volumetric charges may be reduced for customers receiving a demand charge.

OPTION 4 | BUY ALL, SELL ALL

This option reflects a buy all, sell all core structure with all production compensated at its Locational Value. An additional feature of this Option would be the inclusion of a Market Transition Credit.

As summarized, customer consumption is metered separately from production, enabling customer participation in other programs such as demand response to be evaluated and rewarded distinctly.

OPTION 5 | BUY ALL, SELL ALL + GRID SERVICES

This option reflects a buy all, sell all core structure with all production compensated at market based export prices based on their participation in grid services markets. Whereas in Option 4 the customer would be defaulted onto the administratively determined Locational Value export price, Option 5 would default the customer's production into grid services markets. It is assumed that aggregators will serve as the customer's agent in participating in such markets, but individual customer participation is not precluded.

In the next section, we turn to criteria which may be used to gauge the relative strengths of these options and an evaluation of their merits.

EVALUATING IDENTIFIED OPTIONS

Returning to the identified opportunity: net metering has proven potential to incentivize customer adoption of solar. But does net metering support the alignment of supply and demand and thereby help resolve key challenges facing California? Can those challenges be addressed while increasing affordability for all customers and preserving customer choice?

PRINCIPLES

To evaluate the identified compensation structure options, criteria consistent with California's principles must be identified. This evaluation begins with the stated principles of the CPUC in its DER Action Plan[13] and supplements them based on stakeholder input, resulting in the following foundational principles:

Adapted from the CPUC's DER Action Plan

- DER able and incentivized to serve grid needs (Vision Element 2.A)
- Technologically neutral, competitive sourcing (Vision Element 2.C)
- DER valued fully, accurately, and impartially (Vision Element 2.D)
- Sourcing reflects locational value (Action Element 2.3)

Incremental to DER Action Plan

- Grid valued fully, accurately, and impartially; recognized as essential
- Customer choice enabled, practical and informed
- DER should contribute to GHG reductions
- Valuation and incentives determined transparently
- Grid and energy services unbundled
- New technology leveraged to serve customers
- Grid peak-driven infrastructure investment minimized
- Increase affordability of service for all customers
- Ratepayer indifference
- California's solar market grows sustainably

These principles represent a broad range of values and priorities held by policy makers, utilities, market participants, consumer advocates, and environmental interests.

CRITERIA

To operationalize these principles and enable a practical evaluation of the options, the following criteria were derived: Locational Value, Grid Cost Recovery, Customer Choice and Decarbonization. These criteria have been defined as follows for the purposes of this evaluation.

Locational Value

This criterion asks whether the option compensates a customer generator for the locational value of its production as informed by the LNBA. Underpinning this criterion is the CPUC's 2017 endorsement of the LNBA, which states, "the presumption is that the next regime of NEM incentives would be tailored to the relative costs and benefits of DER

13 "DER Action Plan." May 2017. CPUC.

deployment at given locations on the grid."[14]

Principles embedded in this criterion include: *DER valued fully, accurately, and impartially; Sourcing reflects locational value; Valuation and incentives determined transparently; Increase affordability of service to all customers; Peak-driven infrastructure investment minimized*

Grid Cost Recovery

This criterion asks how well the option recovers utility grid costs consistent with cost-causation principles and cost allocation. Because no new fixed or grid charges are assumed for the options under consideration in this evaluation the practical impact of this criterion is to advantage options which limit netting. Underpinning this criterion is the CPUC's conclusion from D.16-01-044, "the principal potential disadvantage of continuing the current full retail rate NEM tariff is economic. The [Investor Owned Utilities] lose revenue from NEM customers, particularly residential NEM customers, because those customers pay less to cover distribution costs through their volumetric rates. This revenue is recovered through increases in rates paid by all customers."[15] Therefore options satisfying this criterion better enable the utility to recover distribution costs which are incurred on an adopting customer's behalf through collecting consumption charges for consumption from the grid.

Principles embedded in this criterion include: *Grid valued fully, accurately, and impartially; Increase affordability of service to all customers; Ratepayer indifference*

Customer Choice

This criterion asks how well the option enables the customer to make an informed choice in adopting DER and whether the option allows customer self-supply. Options satisfying this criterion reflect relative simplicity, clarity, and predictability over the life of an asset from an investing customer's point of view, while enabling self-supply. Embodied in the criterion is recognition that customer generation needs to be financeable, which may imply fixed pricing for a period.

Principles embedded in this criterion include: *DER valued fully, accurately, and impartially; Customer choice enabled, practical and informed; Valuation and incentives determined transparently*

Decarbonization

This criterion asks how well an option contributes to high-renewable scenarios critical to achieving decarbonization targets, especially through encouraging co-location of solar with energy storage. Effective options increase grid flexibility, complementing variable renewable resources by responding to changes in renewable output, providing load shift, ramp, voltage, and/or frequency support. Successful decarbonization policy includes incentives for adopting and leveraging emerging inverter and storage capabilities.

Principles embedded in this criterion include: *DER able to serve grid need; DER contribute to GHG reductions; Leverage new technology to serve customers and the grid; Peak-driven infrastructure investment minimized*

Three principles of the evaluation that were not embedded in the criteria are "technologically neutral, competitive sourcing (Vision Element 2.C)," "unbundling grid and energy services," and "California's solar market grows sustainably." The first was deemphasized because competitive sourcing through distribution and competitive wholesale markets remains an uncertain dimension of California's energy markets. At this time the relative uncertainty of how these markets will work for customer generators, the size of the markets, and whether they will serve to support solar adoption lead the authors to focus on more near-term, predictable principles. The second, unbundling grid and energy services, was deemphasized because it was assumed achievable through any of the options analyzed. The third, growing California's solar market sustainably, is treated as an overarching objective and addressed in the following section, "conclusions and recommendations."

The following section evaluates the identified potential compensation structure options using these criteria.

OPTION EVALUATION RESULTS

The purpose of evaluating the compensation structure options using these criteria is to assess which structures may enable customer generators to make further contributions to the identified principles and criteria. Table 2 shows the relative advantages of each option.

TABLE 2

EVALUATING CUSTOMER GENERATION COMPENSATION OPTIONS

	OPTION	LOCATIONAL VALUE	GRID COST RECOVERY	CUSTOMER CHOICE	DECARBONIZE
1	NEM 2.0	● dark red	● orange	● blue	● orange
2	Net Billing	● yellow	● yellow	● yellow	● yellow
3	NB + Grid Services	● orange	● yellow	● orange	● light green
4	BASA	● blue	● blue	● orange	● dark red
5	BASA Grid Services	● orange	● blue	● dark red	● blue

SCALE BETTER ● blue ● light green ● yellow ● orange ● dark red WORSE

To explain the evaluation results we consider the relative strengths of each option sequentially by criterion.

The strengths of each option relative to the Locational Value criterion hinge on whether the core structure compensates a customer generator at a locationally differentiated value. NEM 2.0 and BASA are opposite in this regard, compensating

14 D.17-08-026, p.44. CPUC.
15 D.16-01-044, p. 81. CPUC.

none and all of production at the Locational Value respectively. Net Billing allows for compensation of exports (only) at the Locational Value. The two Grid Services options rely on market based pricing which may be driven by relative costs and benefits, but unrelated to the LNBA valuation — the export price may be above or below the LNBA-informed price.

The strengths of each option relative to the Grid Cost Recovery criterion depend on whether the utility's distribution costs are recoverable through the adopting customer's volumetric rates. The options ascend in their ability to satisfy this criterion based on how much of the customer's consumption results in a charge: more charges, more cost recovery.

The strengths of each option relative to the Customer Choice criterion reflect the relative simplicity of the transaction from a participating customer point of view and whether the option allows customer self-supply. Here Net Metering has historically proven effective, underpinning the adoption of solar by over 725,000 customers in California; however, the predictability of the customer's return on investment is only as predictable as the underlying rate design, which is increasingly dynamic in California. At the more extreme edge of customer choice lie options defaulting customers into grid services markets, introducing new complexity relative to the alternatives and lowering the ease of engagement by customers. BASA is arguably the simplest transaction structure: customer gets paid a fixed export price for all production for a predictable period, as with a feed-in tariff; however, the structure prohibits customer self-supply, a significant limitation of customer choice. Net Billing mixes two options which are simple when separate, but potentially more complicated when put together.

Finally, the strengths of each option relative to the Decarbonization criterion depend on how well it enables the customer generation to support high-renewable scenarios. Relative to its predecessors, NEM 2.0 begins a transition to incentivizing grid integration through requiring customers to enroll in time of use rates, giving an adopting customer a nudge to orient and size their installation toward production profiles of relative advantage to the grid.

Net Billing goes further to support decarbonization. With Net Billing, the value of self-supply increases relative to exports, pushing the customer toward greater alignment and adoption of storage. Finally, options which default customers into grid services markets provide a distinct advantage: the sourcing of these resources follows an identified grid need. Relative to the "scatter shot" approach to DER deployment underpinning the other options, these advantages are significant from a decarbonization point of view. BASA does little to support decarbonization: neither self-supply nor grid services are brought to bear to support alignment of solar supply and demand. This short-coming could be mitigated by time-differentiated export prices, an option not explored in depth by this analysis.

Overall, the evaluation demonstrates net metering, other core structures, and the tool kit can be honed in pursuit of defined objectives. While Net Billing achieves average results across criteria, the others excel and fall short in various ways. Therefore, the relative weighting would have a significant impact on whether any option stands out.

CONCLUSIONS AND RECOMMENDATIONS

KEY QUESTIONS EMERGING FROM EVALUATION

This evaluation brings the following key questions into focus.

How should the success of NEM 2.0 be assessed?

NEM 2.0 implementation began in 2016 and 2017. While the impacts of this approach are not yet well understood, interconnection data show customer applications are slowing, as featured below in Table 3.[16]

TABLE 3

	Q4 2015	Q4 2016	Delta	Q1 2016	Q1 2017	Delta	Q2 2016	Q2 2017	Delta
Non-Residential	810	906	12%	858	975	14%	1,360	386	-72%
Residential	41,527	33,630	-19%	39,634	26,484	-33%	36,875	16,517	-55%

To date the residential sector has slowed most significantly. Because submission of an interconnection application significantly lags development for non-residential customers, data for this segment will likely show a drop in forthcoming quarters.

There are numerous factors impacting solar adoption in California; concluding this trend is solely attributable to NEM 2.0 oversimplifies the analysis. We suggest the following questions be monitored in 2018 to inform future decisions concerning the effect of NEM 2.0 and contemporary factors. Insights gained from the current structure may be leveraged to support California's next steps.

- **GHG Reductions:** How are existing customer generators contributing to decarbonizing California's power supply? Will new resources have the same impact, diminishing, or increasing?
- **Market Conditions:** Are customers continuing to enroll in net metering? Is the market steady, growing, or contracting? What are growth expectations going forward?
- **Impact of TOU requirement:** Has requiring enrollment in TOU rates for residential net metering customers affected

16 Derived from www.californiadgstats.com. August, 2017.

enrollment in net metering? Has it affected the sizing and orientation of systems? Has it affected the adoption of storage technologies by residential customers?

- **Cost/Benefit:** Are the costs and benefits of NEM 2.0 improved relative to NEM 1.0?

An evaluation of these metrics and questions may serve as a useful foundation for future decision making regarding the merits of NEM 2.0.

Is eliminating a customer's self-supply practical and advantageous?

The BASA options evaluated here would require regulatory limits on self-supply. For the relative advantages of those options to be gained, this limit would need to be physically practical, which may not be assumed. Data on customer owned generators directly serving load behind the meter out of parallel with the grid are limited, but anecdotal evidence suggest it may be impractical to limit the self-supply of motivated customers. The likelihood of customers "cutting the cord" if self-supply is precluded, even for a portion of their load, may warrant further evaluation.

In addition, self-supply has been a primary value-add for adopting customers. A compensation structure that eliminates this value stream must either replace it or, all other things being equal (e.g., customer generator system costs remain consistent), expect declining growth in customer adoption. The net billing options identified here preserve self-supply, effectively pitting retail rates against declining technology cost curves, especially that of storage. This competition may be a productive incentive to support storage adoption while enabling customer generators to make needed contributions to grid flexibility and affordability.

What are the practical challenges of using the LNBA as proposed?

The Net Billing and BASA options rely on the LNBA: the former as a source to inform pricing of exports; the latter for all production. As referenced here, the CPUC has indicated a consistent commitment to locationally differentiated incentives for customer generation, citing the potential for such targeting to reduce the need for investment in transmission and distribution grid infrastructure and local generation resources, while easing grid operations. That body has also acknowledged challenges facing the LNBA methodology in fulfilling this role and ordered further improvements.[17]

Implementation of the ordered improvements will continue iteratively over time; perspectives on its effectiveness will differ; and uncertainty about its fitness for use in valuation will continue — of all conclusions in this analysis, this is perhaps most assured. These conclusions are doubly certain if the methodology is to serve a price-setting function. This is the hazard of a compensation framework which relies on administratively determined prices; one which is equally applicable to the administratively determined retail rate as it is for the LNBA. The buyer may be paying too much, or too little. Unless and until market pricing alternatives identified in the grid services options can serve as viable alternatives, there may be uncertainty about valuation.

Three further challenges to reliance on the LNBA deserve consideration: How will customers accept differentiated incentives? How will utilities process them? And how will vendors adapt marketing of DER under them? Customers may be confused or put off by receiving a different incentive than their in-laws a circuit over; utilities billing systems may require significant investment to track a level of granularity which has never been applied to retail ratemaking; and vendors may be challenged to effectively market or finance their services with specificity? There are three potential ways to address these challenges. First, technological solutions which empower the customer and utility to adapt to more price signals. Second, careful consideration of what the appropriate level of granularity might be. From the service territory, to distribution planning area, to groups of circuits, to circuits, to feeders, to individual customers: there is wide range of granularity enabled by the LNBA methodology. Third, offering all customers a base price for exports regardless of location with adders for locations of particularly value. Arriving at a practical level of granularity may require transition from broad to narrow and experimentation. Technologies which allow both customers and utilities to adapt may be tested, preferably with a sense of urgency.

Are grid services markets viable?

Net Billing and BASA structures would allow for exports or all production to enter grid services markets. Grid services markets include:

- **Wholesale Grid Services:** Under current CAISO tariffs, DER may bid market energy, regulation up, regulation down, spinning reserve and non-spinning reserve.[18] However, active participation by DER providers has been limited. The CAISO has recently renewed an effort — its Energy Storage and Distributed Energy Resources stakeholder initiative — to address challenges associated with DER participation in wholesale markets.[19] The CPUC has provided comparable commitments.[20]

- **Distribution Grid Services:** Through the CPUC's Distribution Resource Planning and Integration of Distributed Energy Resources proceedings, plus individual initiatives of Southern California Edison, numerous distribution grid services demonstration projects are underway. These demonstrations constitute the onset of California distribution services market, in which third-party aggregated DER provide capacity, voltage support, and resiliency services to the distribution system.[21]

17 D. 17-09-026

18 Detailed service definitions at http://www.caiso.com/participate/Pages/MarketProducts/Default.aspx

19 Energy Storage and Distributed Energy Resources Stakeholder Initiative, CAISO.

20 D.17-10-017; R.15-03-011. CPUC.

21 D.16-12-036. CPUC.

The integration of DER into wholesale and distribution markets has been a priority for California, but their viability remains uncertain. Through the referenced CAISO and CPUC initiatives the viability of grid services markets will become clearer. 2018 will be a pivotal year in this regard.

RECOMMENDATIONS

This evaluation attempts to evenly balance criteria and concludes that Option 2, Net Billing with exports compensated at the LNBA-informed export price for solar would be a substantial improvement to current policy, allowing for locationally differentiated compensation, improved grid cost recovery, and deeper decarbonization though storage enabled alignment of solar supply and demand.

This structure would lead to three potential outcomes:

- where the LNBA-based price paid on exports provides an adequate return, customers will adopt solar (with or without storage) in areas advantageous to the grid, easing grid planning and operations while lowering grid costs;
- where the LNBA-based price paid on exports does not provide an adequate return, customers are incentivized to maximize self-supply, most practically achieved through solar plus storage;
- where neither the LNBA nor storage are advantageous to the customer, they will maintain the choice to adopt while making increased contributions to grid cost recovery.

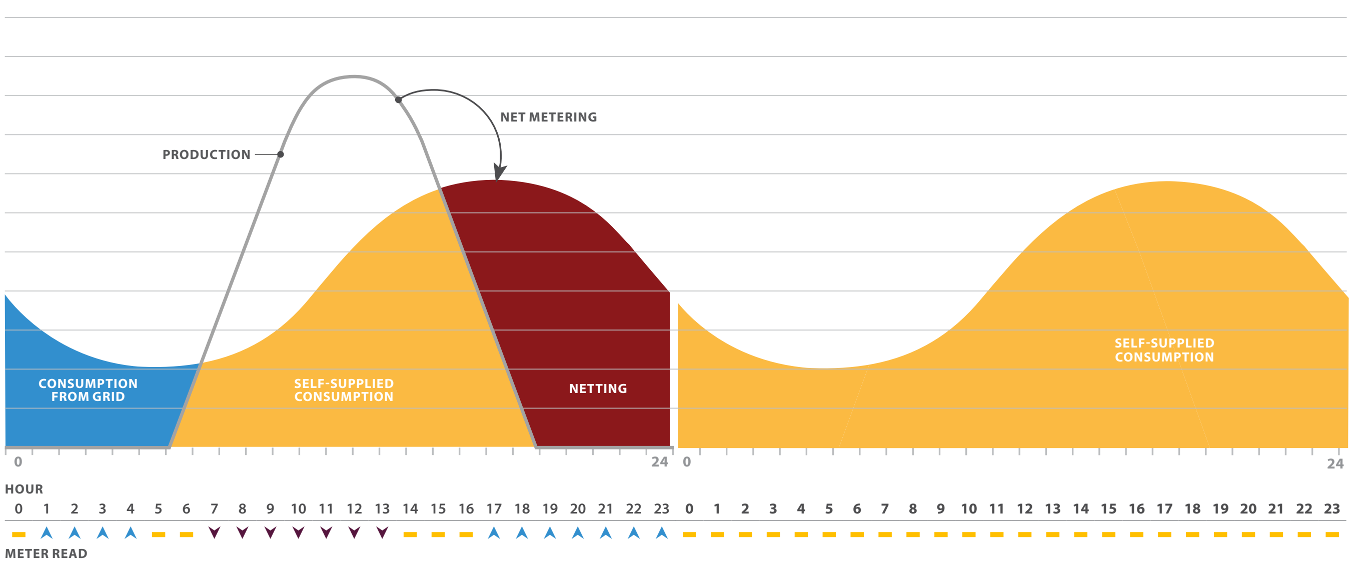
These advantages are more acute where and when mature grid services markets can replace the LNBA as a tool for pricing exports. As more experience with grid services is gained, these advantages may become increasingly practical.

To ease the transition from NEM 2.0 to Net Billing, two measures are recommended. First, enable Transferable Credits, allowing credit earned by a customer for exports to be transferred to other customers at the discretion of the customer generator. This will introduce liquidity into the market, especially if "size-to-load" requirements are lifted, allowing customers who are not in high-value locations to invest in those locations and receive corresponding reductions in their energy costs. Second, adopt temporary Market Transition Credits, smoothing the change from the current compensation levels to locationally differentiated levels. There are many ways this could be structured. One would be to "step- down" the Market Transition Credit in stages as the industry hits certain installed capacity benchmarks (similar to early California Solar Initiative designs). This step-down approach would have the added advantage of allowing for storage to scale up and reduce costs while signaling to industry that there will be a market for behind the meter storage.

Timely adoption of a Net Billing structure may also pave the way for grid friendly transportation electrification. Net metering would allow non-simultaneous netting of vehicle electrification load, an accounting tool which would undermine a principal benefit of vehicle electrification from a societal perspective (i.e., increased throughput leads to decreased rates). To the extent net metering continues into the next decade when electric vehicle adoption is forecasted to surge, a huge class of customers may come to expect low or zero cost service from the grid. On the other hand, a Net Billing structure would encourage electric vehicle customers to charge while the sun shines, or store their solar-generated energy to charge their vehicles at other times.

FIGURE 4

FROM NET METERING TO NET BILLING, SOLAR TO SOLAR PLUS STORAGE



A final advantage of Net Billing deserves consideration: Net Metering's reliance on the retail rate limits the flexibility of California policymakers – the price paid to solar is intertwined with retail ratemaking, a clunky policy making process with implications and complications extending far beyond customer generation. This approach has supported customer adoption to date because retail rates were going up and solar costs were coming down. It is not difficult to imagine these trends being reversed, with federal trade or tax policy turning against solar. Net Billing on the other hand compensates exports at a price determined by California policy-makers, allowing for the adoption of anchors and adders with relative ease compared to Net Metering. In this sense, Net Billing allows California alone to determine whether solar is sustained.

Based on this evaluation we recommend California policy-makers move expeditiously to transition the state's solar compensation framework toward a Net Billing structure. As provided, the transition may be eased in several ways and informed by data and insight gained through evaluation of NEM 2.0, helping to sustain growth in customer adoption and achieve the levels of forecasted solar adoption.

APPENDIX A

DEFINING ANCHORS AND ADDERS

Anchors

- *Minimum Bill*
  A minimum bill or minimum charge is the minimum amount that the utility can charge customers for service. This charge only applies to customers whose monthly usage falls below the amount required to support distribution and billing related costs. Also referred to as *minimum charge*[22,23,24]

- *Standby Rate*
  Standby rates are designed to cover the cost of standby electric service when a customer generator is not operating as intended. Currently California NEM eligible customer generators are exempt. Also referred to as *standby fees* or *standby charges*.[25,26,27,28]

- *Non-Bypassable Charge*
  A volumetric charge applied on all customers' bills (even if they purchase electricity from another supplier). For California NEM customers, this can apply to netted out consumption from the grid (1.0) or to total consumption from the grid during each metered interval (2.0).[29,30,31]

- *Demand Charge*
  Charge for electric service based on the consumer's maximum electric capacity usage and calculated based on the billing demand charges under the applicable rate schedule. Currently, demand charges only apply to commercial and industrial customers in California.[32,33]

- *Interconnection Charges*
  A charge levied by network operators on other service providers to recover the costs of the interconnection facilities (including the hardware and software for routing, signaling, and other basic service functions) provided by the network operators.[34,35]

- *Required Time of Use Rate*
  Requirement that a customer generator enrolls in a time of use rate as a condition of net metering.

- *Prohibition on Exports*
  Prohibiting the exports of power from a customer generator to the grid. This may be limited to particular intervals.[36,37]

22 CPUC: "A minimum bill or minimum charge is the minimum amount that the utility can charge customers for service. This charge only applies to customers whose monthly usage falls below the amount required to support distribution and billing related costs... Some utilities calculate minimum bill as a daily charge, which will add up over the course of the month to roughly $5 or $10." http://www.cpuc.ca.gov/General.aspx?id=12187

23 SCE: "The minimum charge (also referred to as the Balance of Minimum Charge or the 'Bal of minimum charge' as it may appear on your bill) is a delivery charge that helps support the maintenance and operation of providing electricity. This charge is calculated on a daily basis and only applies when your total Delivery Charges for the month fall below approximately $5 for those enrolled on California Alternate Rates for Energy (CARE), Family Electric Rate Assistance (FERA), multifamily and medical baseline rate plans or approximately $10 for all other residential users." https://www.sce.com/wps/wcm/connect/8245d565-abae-4419-9d33-40ab30d8ae14/SCE_FrequentlyAskedQuestions_AA.pdf?MOD=AJPERES&attachment=false&id=1447702669699

24 PGE: "The charges for the Minimum Bill include components for the generation of electricity and the delivery of energy. The generation portion of the bill is used to pay for the electricity itself, while the delivery portion is used to pay for the transportation of the electricity over PG&E's grid. On March 1, 2016, the Minimum Bill, which previously was applied to the combined total of delivery and generation charges, will now only be applied to the delivery charge." https://www.pge.com/en_US/residential/rate-plans/how-rates-work/rate-changes/minimum-bill-charges/minimum-bill-charges.page

25 SCE: "Standby is a Southern California Edison (SCE) electric rate for accounts with generators that interconnect to and operate in parallel with SCE's electric system. On this rate, we provide back-up electric service when your generator(s) is not operating as intended." https://www.sce.com/wps/wcm/connect/ff018366-cb7a-4441-a7af-e9582ebbf0cd/Standby+FAQ+Sheet+r3_WCAG_K.pdf?MOD=AJPERES&attachment=false&id=1468951849013

26 PGE: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_S%20(Sch).pdf

27 NY PSC: Cases 15-E-0751 & 15-E-0082 http://www3.dps.ny.gov/W/PSCWeb.nsf/All/8A-5F3592472A270C8525808800517BDD?OpenDocument

28 SDGE: "Solar Customers who are taking service under the Utility's Net Energy Metering tariff are exempt from standby charges. In addition, Solar Customers which are less than or equal to one megawatt to serve load and who do not sell power or make more than incidental export of power into the Utility's power grid are also exempt from standby charges. Non solar customers taking service under one of SDG&E's Net Energy Metering schedules may be exempt from standby charges pursuant to PU Code Section 2827." http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_S.pdf

29 PGE: "Nonbypassable charges involve costs that were included in bundled service bills and are now separately listed. Customer generation departing load customers may receive bills from PG&E for these charges even when they no longer receive electric service from PG&E. Nonbypassable charges that may apply include the Public Purpose Programs (PPP) and the Nuclear Decommissioning (ND) Charge." https://www.pge.com/en_US/business/services/alternatives-to-pge/departing-load-options/departing-load-options.page

30 CPUC: D. 16-01-044, page 88 "Under [NEM 1.0], NEM customers pay the nonbypassable charges embedded in their volumetric rates. They do so, however, only on the netted-out quantity of energy consumed from the grid, after subtracting any excess energy they supply to the grid. NEM successor tariff customers must pay nonbypassable charges on each kWh of electricity they consume from the grid in each metered interval" http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf

31 CPUC: Resolution E-4795 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K911/163911492.PDF

32 CPUC: "A non-coincident demand ("NCD") charge (in $/kW) is assessed on the customer's maximum demand in any 15-minute interval during the billing cycle. A peak-related (or coincident) demand charge ("CD charge") is assessed on the customer's maximum demand in any 15-minute interval during the peak TOU period." http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2017/SB%20695_Master%20Draft_final_5-12-17.pdf

33 PGE: "To help keep the supply of electricity reliable in California, some time-of-use rate plans, like A10 Time-of-Use, include a Demand Charge to encourage businesses to spread their electricity use throughout the day. This Demand Charge is calculated by using the 15-minute interval during each billing month when your business uses its maximum amount of electricity. As a benefit to this type of rate plan, regular electricity usage charges are approximately 30% lower than for a comparable rate plan without a Demand Charge--giving you the opportunity to save on your bill if you can lower your highest usage 15-minute interval." https://www.pge.com/en_US/business/rate-plans/rate-plans/time-of-use/time-of-use.page

34 OECD: https://stats.oecd.org/glossary/detail.asp?ID=4965

35 CPUC: "Customer-generators with facilities under 1 MW must pay a pre-approved one-time interconnection fee based on each IOU's historic interconnection costs." http://www.cpuc.ca.gov/General.aspx?id=3800

36 Hawaii PUC: page 118 http://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A15J13B15422F90464

37 HECO: https://www.hawaiianelectric.com/clean-energy-hawaii/producing-clean-energy/customer-self-supply-and-grid-supply-programs

Adders

- *Capacity Payments*
  Awarding a customer generator a payment or credit based on load-modifying or supply services that distributed energy resources provide via the dispatch of power output for generators or reduction in load that is capable of reliably and consistently reducing net loading on desired distribution infrastructure.[38,39]

- *Locational Adders*
  Awarding a customer generator a payment or credit reflecting the resource's value in certain locations.[40]

- *Environmental Value*
  Awarding the customer generator a payment or credit for benefits based on reductions in the social cost of carbon and/or other environmental metrics.[41]

- *Renewable Energy Credit*
  Awarding the renewable portfolio standard compliance credit to the customer generator rather than the off-taking utility.[42]

- *Market Transition Credit*
  Awarding additional compensation to a customer generator during a defined period of time that recognizes the importance of continued clean energy development, the needs of the market, and the existence of values not yet identified.[43]

- *Price Enrichment Based on Time of Delivery*
  Awarding exports based on the time of delivery, reflecting relative value at different points in time to the distribution system.[44]

- *Grid Services*
  Awarding a customer generator payments for additional services provided to the grid (e.g., voltage support, distribution capacity, and/or reliability/resiliency) as apart of or incremental to self-supply credits.[45]

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38 CPUC: D. 16-12-036, page 8 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M171/K555/171555623.PDF

39 NY PSC: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/8A-5F3592472A270C8525808800517BDD?OpenDocument

40 NY PSC: Cases 15-E-0751 & 15-E-0082 http://www3.dps.ny.gov/W/PSCWeb.nsf/All/8A-5F3592472A270C8525808800517BDD?OpenDocument

41 NY PSC: Cases 15-E-0751 & 15-E-0082 http://www3.dps.ny.gov/W/PSCWeb.nsf/All/8A-5F3592472A270C8525808800517BDD?OpenDocument

42 CPUC: "Renewable Energy Credits (RECs) are among several factors that may affect the economics of solar and other renewable DG facilities, and as such may play an important role in driving the deployment of renewable DG in California and achieving the goals of California Renewables Portfolio (RPS). A REC confers to its holder a claim on the renewable attributes of one unit of energy generated from a renewable resource. A REC consists of the renewable and environmental attributes associated with the production of electricity from a renewable source. RECs are "created" by a renewable generator simultaneous to the production of electricity and can subsequently be sold separately from the underlying energy." http://www.cpuc.ca.gov/General.aspx?id=5913

43 NY PSC: Cases 15-E-0751 & 15-E-0082 Recognizing the importance of continued clean energy development, the needs of the market, and the existence of values not yet identified http://www3.dps.ny.gov/W/PSCWeb.nsf/All/8A5F3592472A270C8525808800517BDD?OpenDocument

44 NY PSC: Cases 15-E-0751 & 15-E-0082 http://www3.dps.ny.gov/W/PSCWeb.nsf/All/8A-5F3592472A270C8525808800517BDD?OpenDocument

45 IDER: http://drpwg.org/wp-content/uploads/2016/07/CSFWG-Sub-Team-1.-Summary-Conclusions-and-Recommendations.pdf

APPENDIX B

SELECTED CUSTOMER GENERATOR COMPENSATION STRUCTURES, PROPOSED AND ADOPTED

	NET METERING	NET BILLING @ EXPORT PRICE	BUY ALL, SELL ALL @ EXPORT PRICE	ANCHORS	ADDERS	NOTES
1	Hawaii Customer Self Supply			Export prohibited + Minimum bill		Driven by DG grid impact; Market slowly adapting
2	CALSEIA			NBC (partial)		
3	SEIA/Vote Solar			Interconnection Charge		
4	Sierra Club @ TOU			TOU		
5	CPUC NEM 2.0 @ TOU			Interconnection + NBC		Up to 7.5% of peak capacity
6	ORA			Installed Capacity Fee (variation on interconnection charge)		
7	NRDC			Demand Charge		
8	Nevada			Excess generation paid share of retail rate declining from 95% to 75% over time		Final policy pending
9	New Hampshire			Excess generation paid share of retail rate (100% T and G; 25% D) + NBCs on gross consumption + monthly true up		No statewide cap; Production meters required
10		Gridworks Option 2 @ loctional value and 3 @ market price		Interconnection + NBC + managed demand charge	Transferrable Credits; temporary Market Transition Credit	
11		New York @ Locational Marginal Price			Capacity Values (wholesale, distribution, targeted distribution) + Environmental Value + Market Transition Credit	Locational differentiation through LMP and distribution capacity
12		PG&E @ Generation Rate		TOU + Demand + NBC + Monthly True-up		
13		Hawaii CGS @ avoided cost (fixed)		Minimum Bill + instantaneous netting + monthly true up		
14		Hawaii Smart Export @ TOD		Minimum Bill + Off Peak Export Uncompensated + Instantaneous netting		Exports at average annual marginal cost of generation
15		SCE @ avoided cost		Grid Charge (Variation on a minimum bill)	REC	
16		SDG&E (Unbundled Rate) @ LMP		System Access Fee (variation on a minimum bill) + PPP + Grid Use Charge + TOU		
17		Arizona @ declining proxy rate		Consumption at specific solar customer charge + Grid Charge + Demand Charge		
18			Maine @ declining discounted retail rate			Rate = 90% of T&D; 100% of G in year one with T&D stepping down 10% each year
19			TURN @ gen + Adder			
20			SDG&E (Sun Credit) @ gen	Stand-by + Interconnection + Monthly True-up		
21			Gridworks Option 4 @ Loctational Value and 5 @ Market Price	Interconnection + NBC + managed demand charge	Transferrable Credits + temporary Market Transition Credit	

Indicates adopted policy

Indicates stakeholder proposal in CPUC R.14-07-002

Indicates options considered in Gridworks' paper, "Sustaining Solar Beyond Net Metering."

APRIL 2017

NEW OPPORTUNITIES FOR SOLAR THROUGH GRID MODERNIZATION

How California & New York are Building Grids that Encourage the Growth of Distributed Energy Resources

AUTHORS:
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Brandon Smithwood
Rick Umoff

SEIA Solar Energy Industries Association®

EXECUTIVE SUMMARY

Lawmakers and utility regulators in California and New York have been extensively engaged in efforts to modernize the electric distribution grid. This paper draws on the experience of Solar Energy Industries Association (SEIA) staff in each jurisdiction and explains how these efforts are creating new opportunities for solar power.[1] The paper describes the policy and political landscape in each state and summarizes the ways in which regulators are currently addressing grid modernization. We identify common elements of these efforts, which include: 1) updating utility system planning; 2) identifying alternatives to traditional utility investments; 3) establishing robust cost benefit frameworks; 4) modifying compensation frameworks to drive investments in distributed energy resources (DER), and 5) making utility investments in technologies that bring new functionality to the grid itself. Future papers will drill down into the details of these issues and discuss the pace of change, whether grid modernization efforts are bearing fruit, and obstacles to implementation.

INTRODUCTION TO GRID MODERNIZATION

For decades, electric distribution utilities have been upgrading their systems with new capabilities and better equipment to make their systems safer, more reliable and less costly to operate. But with more customers than ever producing their own clean power with solar and other DER, energy regulators, electric utilities and solar firms are now faced with new operational conditions as well as new opportunities.

ABOUT THIS WHITEPAPER SERIES

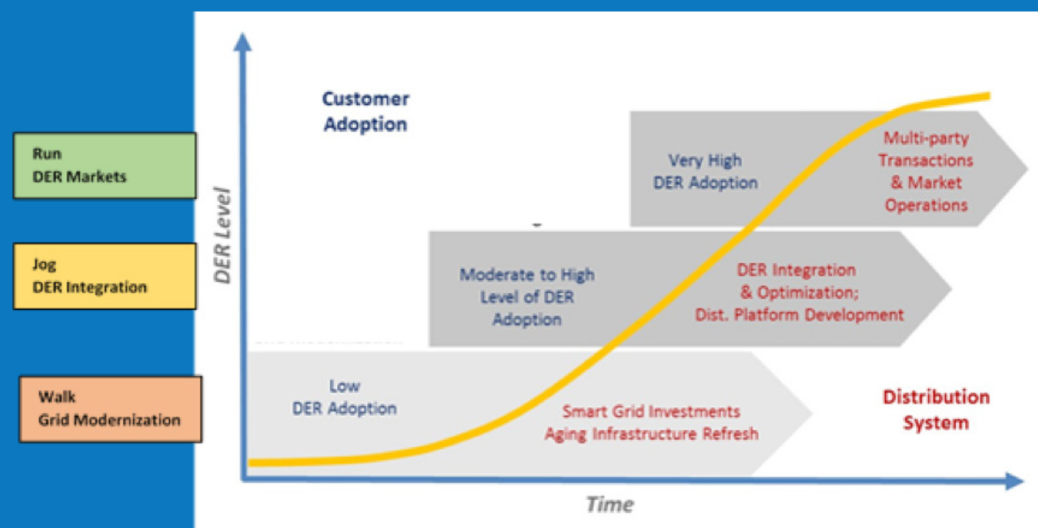
This series of SEIA policy briefs takes an in-depth look at state-level efforts to modernize the electric utility grid. Built during the last century, the United States electric grid was primarily designed to transport electricity from central station power plants to end-use customers. But with rapid growth of distributed energy resources such as solar, customers are increasingly taking charge of their own energy. Today's electric grid must allow distributed energy technologies to flourish and provide reliable, low-cost power for consumers. Distributed energy resources, like solar, can also provide power where it is needed most and help avoid investments that a utility would otherwise need to make.

This series explores the elements of electric grid modernization, compares the ways in which two leading states are tackling these issues, and discusses how these efforts are creating new opportunities for solar power. Grid modernization efforts in states present significant risks and opportunities for solar. These efforts will determine how much new solar and other distributed energy resources can interconnect to the grid, identify areas where solar can provide grid services in lieu of utility investments, and in some states, will shape the future of net energy metering.

[1] SEIA's state affairs team is actively involved in proceedings in these two states, and has filed comments individually and as part of coalitions on key aspects of grid modernization dockets, and regularly engages with regulators on these and other issues.

The grid must be enhanced to encourage the widespread use of clean distributed energy resources, such as solar power. Grid upgrades must also be executed in a way that allows ratepayers to save money versus business-as-usual utility spending on distribution infrastructure. New value and compensation frameworks must also be created to facilitate the deployment of DER in strategic locations that can yield benefits to ratepayers.

Thus, energy regulators across the country, have started a host of dockets to consider changes to utility practices. California and New York have made considerable progress. But even with progress being made on the coasts, regulators and utilities are still in the earliest stages of modernizing the grid. As colleagues at More than Smart have described the process of creating a more modern grid, even leading states are still in the walking phase of More than Smart's walk, jog, run framework. Shown in the figure, even leading states haven't hit the ground running. We describe state efforts in California and New York below.



Source: Newport Consulting: Walk, Jog, Run Framework Toward Grid Modernization.

GRID MODERNIZATION IN CALIFORNIA

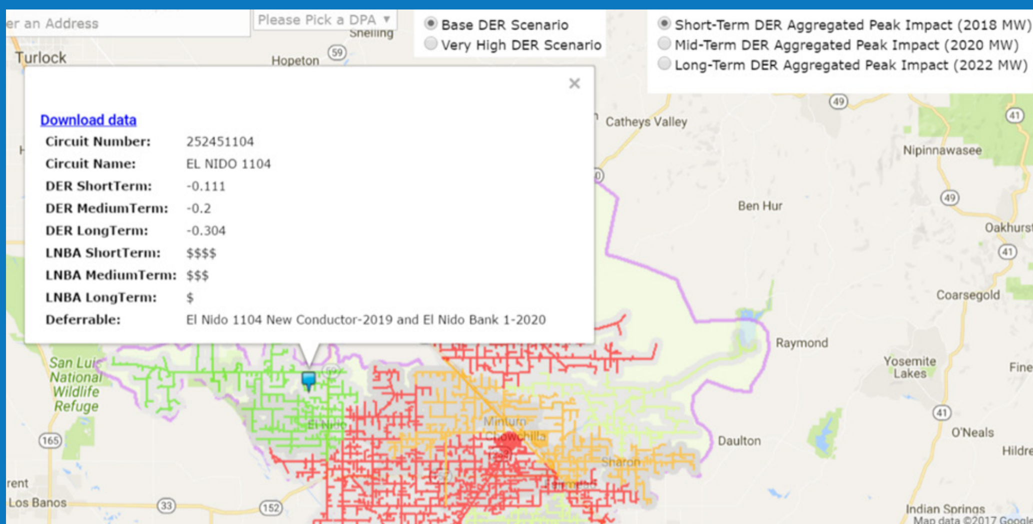
Passed in 2013, Assembly Bill 327 launched a series of regulatory proceedings that will profoundly shape California's solar market, the largest in the country. The bill instructed the California Public Utilities Commission (CPUC) to undertake comprehensive residential rate reform for the first time since the energy crisis at the turn of the millennium, and move customers, on at least a default basis, to time-of-use rates by the end of the decade. This ambitious bill also tasked the CPUC with consideration of a NEM-successor tariff and review of utility Distribution Resource Plans.

[2] For most states DER penetrations are low enough that dramatic changes to grid capabilities and tariffs are unwarranted

[3] Resnick Sustainability Institute at the California Institute of Technology, "More than Smart; A Framework to Make the Grid More Open, Efficient and Resilient" (August 2014). Available at: http://morethansmart.org/wp-content/uploads/2015/06/More-Than-Smart-Report-by-GTLG-and-Caltech-08.11.14.pdf

In 2016, the CPUC retained full retail net metering provided that net metering customers: 1) pay non-bypassable charges on a gross- rather than net-basis; 2) pay a one-time interconnection fee; and 3) take service on a time-of-use rate.[4] The CPUC also signaled that it would revisit the net metering tariff beginning in 2019 after significant changes to rates came to a conclusion. Come 2019, the decision stated, the Commission would also have insights and tools from proceedings looking at revamping distribution system planning, operations, and investment.

The move to more location-specific valuation, and possibly location-specific compensation, is occurring in California's Integrated Distributed Energy Resources (IDER) Proceeding[5] and Distributed Resources Planning (DRP) Proceeding.[6] The DRP proceeding is developing a locational net benefit analysis (LNBA).



Locational Net Benefit Value "Heat Map" from PG&E's LNBA pilot

The LNBA is an evolution of the cost-effectiveness framework that the CPUC has used to evaluate distributed energy resources. Regulators have identified certain avoided costs that are "system level" values and do not vary by location across a utility service territory. They are also looking to improve and harmonize these system values through a process that is underway in the IDER proceeding. Transmission and distribution avoided costs, local capacity needs, and energy losses, which historically have been evaluated on a system-wide average basis will now vary at a much more geographically granular level: at the distribution planning area, substation level, or even circuit by circuit. Utilities are also evaluating other specific values such as voltage, power quality and reliability and resiliency and may add further values, such as asset life extension, data collection and situational awareness.

[4] California Public Utilities Commission, D.16-01-044, "Decision Adopting Successor to Net Energy Metering Tariff" (January 2016)

[5] California Public Utilities Commission, R.14-08-013 "Order Instituting Rulemaking on Distribution Resources Planning" (August 2014)

[6] California Public Utilities Commission, R.14-10-003 "Order Instituting Rulemaking on Integrated Distributed Energy Resources" (October 2014)

The locational net benefit analysis represents a significant step forward in providing transparency about utility distribution system needs that have the potential to be met by distributed energy resources in lieu of traditional utility equipment. However, questions remain over how values are calculated, particularly for services such as voltage management, which are not well valued by evaluating the ability of a DER to modify load. There are also questions about whether an avoided cost methodology is itself appropriate and how utility system needs should be identified when needs change within a utility's annual planning cycle.

GRID MODERNIZATION IN NEW YORK

New York's overall policy objectives set in the State Energy Plan are to obtain 50% of the state's electricity from renewables by 2030 and reduce greenhouse gas emissions by 40% from 1990 levels by the year 2030.[7] To realize these goals, New York launched the Reforming the Energy Vision (REV) effort at the New York Public Service Commission (PSC). REV is a multifaceted initiative that aims to reduce ratepayer surcharges, create new markets for energy and technology companies, update aging utility infrastructure at a lower cost than business as usual, create a grid that's less prone to outages, and reduce greenhouse gas pollution.[8]

As part of REV, the PSC also updated its benefit cost framework. The PSC selected the state's investor owned utilities as transactive grid operators and required them to prepare Distributed System Platform Implementation Plans (DSIPs) for transitioning to their new role. The PSC also required utilities to prepare a supplemental plan prepared jointly by all the utilities that proposed shared tools, processes and protocols to help operate a modern grid. The PSC directed the utilities to include adequate and reasonable assumptions about the uptake of DER in their load forecasts; provide third parties sufficient information to evaluate the best locations for solar systems; and describe a process for integrating cost effective DER at a system-wide scale. The initial DSIPs filed at the PSC included extensive analysis of utility grid operations.

The PSC has also pursued alternatives to utility investments through individual rate cases. In early 2014, the PSC required Consolidated Edison to make investments in distributed energy resources to avoid a $1 billion substation upgrade in Brooklyn/Queens.[9] Called the Brooklyn/Queens Demand Management (BQDM) effort, the PSC then directed the state's other investor owned utilities in their DSIP filings to identify similar areas where demand could be met with alternative investments.

> *"A better understanding of the distribution grid will help solar projects, particularly by creating more certainty around the distribution system's ability to interconnect new systems at different locations."*

[7] New York State Energy Planning Board, "2015 New York State Energy Plan" (June 2015). Available at: https://energyplan.ny.gov/

[8] New York PSC, Case 14-M-0101, "Order Adopting Regulatory Policy Framework and Implementation Plan" (February 2016).

[9] New York State Public Service Commission, Case 14-E-0302 "Order Establishing Brooklyn/Queens Demand Management Program" (December 2014). Available at: http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-E-0302&submit=Search+for+Case%2FMatter+Number

At approximately the same time the PSC also launched an effort to develop an interim and long-term tariff for solar systems, and other DER providers, that would send more accurate price signals than the ones sent through retail rate net energy metering. Called the Value of Distributed Energy Resources (VDER) proceeding, this case attempts to unbundle the various components of value contained in electric rates, including energy value, capacity value, environmental and locational value[10]. Although regulators recognized that they did not have the analysis to provide precise valuation, they established proxy values and a transition credit mechanism to estimate these values for the first phase of the tariff. A second phase of the proceeding will attempt to provide more accurate valuations.

THE COMMON ELEMENTS OF GRID MODERNIZATION

Although public utility commission discussions about modernizing the electric grid are unfolding in different ways, the elements of grid modernization include the following five main concepts: 1) updating utility system planning; 2) identifying alternatives to traditional utility investments; 3) establishing robust cost benefit frameworks, 4) modifying compensation frameworks to drive investments in DER, and 5) making utility investments in technologies that bring new functionality to the grid itself. We unpack these elements below.

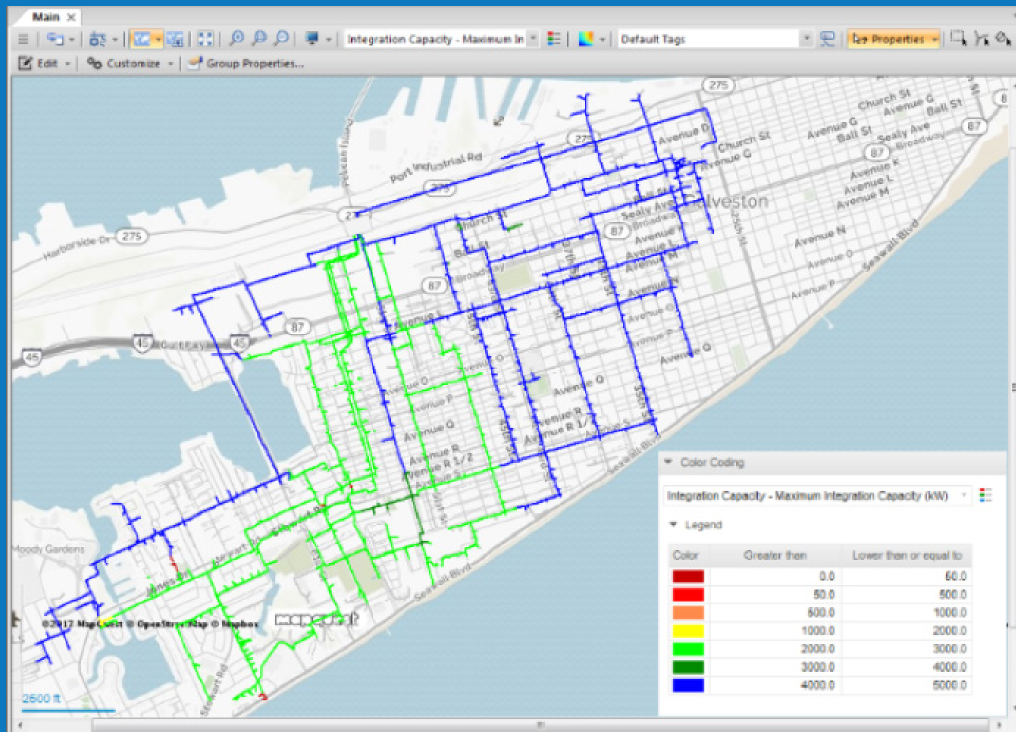
Updated Utility System Planning and Transparency

Arguably the foundation to all grid modernization efforts involves a fundamental shift in the way electric utilities plan to meet electric system needs. This planning should view all DER as an asset to the grid instead of a problem to be avoided, as it is sometimes perceived today.

A better understanding of the distribution grid will help solar projects, particularly by creating more certainty around the distribution system's ability to interconnect new systems at different locations. Currently developers of larger projects face uncertain prospects regarding interconnection costs and timing for their projects: will the developer need to pay for distribution system upgrades? How long will the interconnection process take? Better planning ultimately involves the utilities releasing more detailed analyses of system needs such as line-by-line analysis of the ability of the existing grid to incorporate solar systems, often referred to as hosting capacity analysis. This information should be made available more frequently, not simply as part of three-or-five -year capital improvement plans. Accurate and timely hosting capacity analyses should take a considerable amount of uncertainty and delay out of the interconnection process.

Better planning can also ensure that unnecessary utility investments are avoided and opportunities for DERs to provide "non-wires alternatives" are identified. Solar firms can help provide solutions to grid problems, once they know what the problems are and what the actual constraints of the grid look like. To enable these opportunities, utilities should make more information about utility system operations available to solar companies on a regular basis.

[10] New York State Public Service Commission, Case 15-E-0751 "Notice Soliciting Comments and Proposals on an Interim Successor to Net Energy Metering and of a Preliminary Conference" (December 2015). Available at: http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-E-0751&submit=Search+for+Case%2FMatter+Number

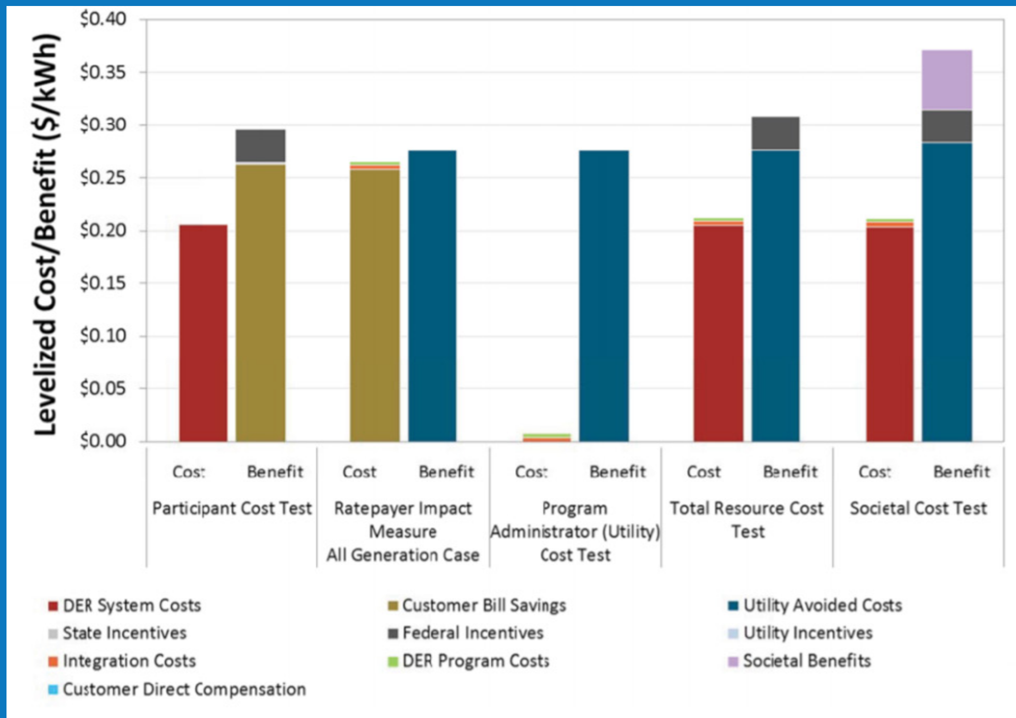


Example of hosting capacity analysis from software provider Eaton CYME

Establishing a Robust Benefit Cost Framework

Grid modernization efforts should also include establishment of a robust and transparent benefit cost framework to inform utility planning and ensure full and fair valuation of distributed energy resources vis-à-vis conventional utility investments. A benefit cost framework should take into consideration values including, but not limited to bulk system values, distribution system values, reliability and resiliency, and societal values. Additionally, the framework should consider costs associated with grid modernization efforts, including potential costs resulting from integrating DERs into the grid. The benefit cost framework can be used to place a value on DERs for the benefits they deliver, which may inform tariff development or solicitations of DERs on a portfolio basis.

> ***Once utility planners have published better ongoing data about system needs, utilities, regulators and solar firms can then identify strategic locations on the grid itself where traditional capital investments can be offset by DER alternatives.***



Cost Benefit Analysis from SEIA and Vote Solar's California Net Metering Proposal

Identifying Alternatives to Traditional Utility Investments

Pilot projects in New York, California, and elsewhere have sought DERs in lieu of more traditional grid upgrades. California used DERs to meet needs created by the unexpected closure of the San Onofre Nuclear Generating Station[11] and is repeating this process to meet needs in Santa Barbara[12]. New York is conducting a similar effort to avoid a distribution substation in Queens.[13]

Improved utility distribution planning can facilitate using NWAs at scale. Once utility planners have published better ongoing data about system needs, utilities, regulators and solar firms can identify strategic locations on the grid itself where traditional capital investments can be offset by DER alternatives. NWAs are a new opportunity for DERs that can save ratepayers money by avoiding costly upgrades to the distribution system by promoting demand side management solutions instead.

Modifying Value/Compensation Frameworks

Another element of grid modernization involves developing compensation frameworks or rate design reforms to encourage DER providers to build projects in strategic locations. This includes making valuation more locationally dependent, developing solicitations, rates, and tariffs to meet needs in areas of the distribution system with identified needs, and potentially modifying underlying tariffs. In areas with high levels of solar deployment modification of tariffs could include net metering.

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[11] https://www.greentechmedia.com/articles/read/California-PUC-Looking-to-Replace-Closed-Nuclear-and-Outlawed-Gas-With-More

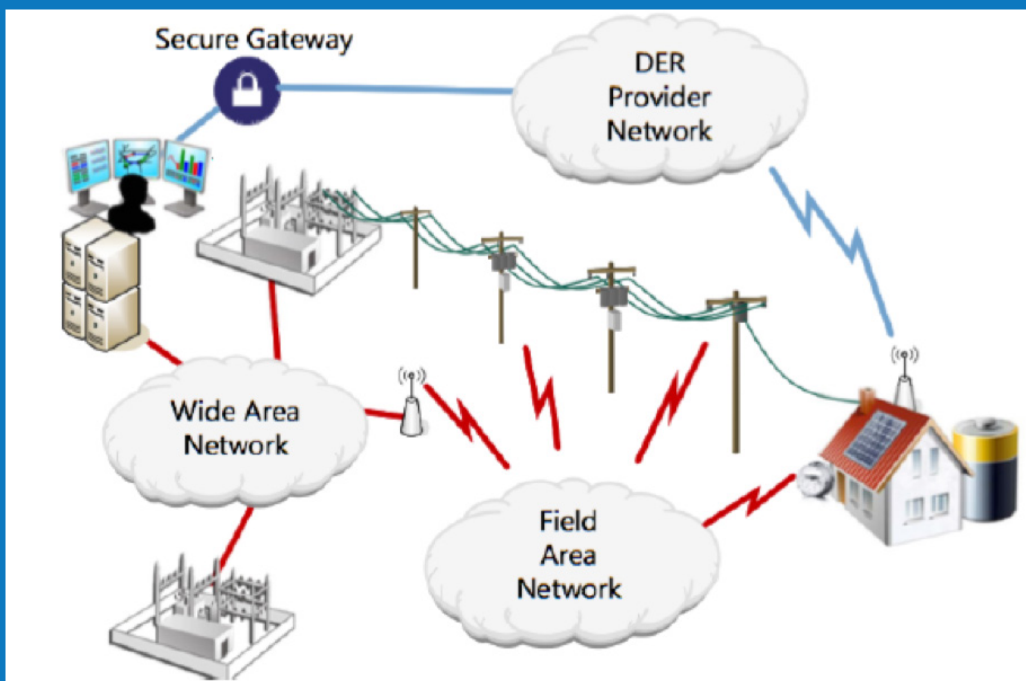
[12] Jeff St. John, SoCal Edison Seeks 55MW of Distributed Energy Resources to Keep Santa Barbara's Lights On, Greentech Media March 7, 2017 https://www.greentechmedia.com/articles/read/socal-edison-needs-to-keep-the-lights-on-with-distributed-energy

[13] http://www.utilitydive.com/news/coned-brooklyn-queens-non-wire-alternative-project-installs-first-microgrid/432380/

Updating the Functionality of the Grid Itself

The last element involves making improvements to the functionality of the grid itself. These investments in infrastructure may include monitoring technologies to help more easily identify areas of system constraints, they may provide more real-time data about system needs, technologies that allow DER to even out power flows, and metering infrastructure to provide more accurate and timely information about customer electricity usage as well as billing. Utilities across the country vary widely on the extent to which they use these tools.

In this area of grid modernization there is another balance between utility and DER investment. Utilities may need investments, like distributed energy resource management systems (DERMs). But there are also potential opportunities for DERs, particularly with the capabilities of smart inverters which can provide much more data than utility equipment and have the capability to help manage power quality on the distribution system.



Visualization of a DER communications and control network, Southern California Edison

CONCLUSION

Leading states are tackling grid modernization through different means, but the elements of the discussions are strikingly similar. Furthermore, grid modernization discussions have moved beyond thought exercises by academics and think tanks. In California and New York, public utility commissions have required the execution of significant pilot programs and have begun requiring utilities to provide new analysis and redesign rates to accomplish their objectives.

But are utilities providing enough useful information on system planning in these dockets? How are new rate designs contributing to efforts to add more distributed energy resources into a more transactive grid? Will these efforts keep their current momentum or bog down based on lack of financial motivation on the part of utilities to participate? We will dive into these questions in future papers.

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Celebrating its 43rd anniversary in 2017, the Solar Energy Industries Association is the national trade association of the U.S. solar energy industry, which now employs more than 260,000 Americans. Through advocacy and education, SEIA® is building a strong solar industry to power America. SEIA works with its 1,000 member companies to build jobs and diversity, champion the use of cost-competitive solar in America, remove market barriers and educate the public on the benefits of solar energy.

SEIA Solar Energy Industries Association®

JULY 2017

IMPROVING DISTRIBUTION SYSTEM PLANNING TO INCORPORATE DISTRIBUTED ENERGY RESOURCES

The Second in SEIA's *Improving Opportunities for Solar Through Grid Modernization* Whitepaper Series

AUTHORS:
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Brandon Smithwood
Rick Umoff

Solar Energy Industries Association®

EXECUTIVE SUMMARY

Built during the last century, the United States electric grid was primarily designed to transport electricity from large central station power plants to end-use customers. But with rapid growth of distributed energy resources, such as solar, resulting from falling costs and technological advances, customers are increasingly taking charge of their own energy. These resources offer the promise of a more innovative, economic, and cleaner electric grid.

This is a future in which distributed energy resources (DERs), such as solar power, will play an important role providing power and grid services where they are needed most. To reach this goal, however, distribution grid planning must evolve from a largely closed process (a "black box") to one which allows transparency into system needs, plans for distributed energy resources growth, and ensures that the capabilities of distributed energy resources are fully utilized.

This paper is the second in SEIA's series on grid modernization and focuses on distribution planning and operations, which is foundational to various facets of grid modernization. We start by reviewing the utility distribution system planning process today and identify key processes and concepts. Next, we discuss how two leading states are attempting to modernize distribution planning to both plan for distributed energy resources as well as leverage their capabilities.

ABOUT THIS WHITEPAPER SERIES

This series of SEIA policy briefs takes an in-depth look at state-level efforts to modernize the electric utility grid. Built during the last century, the United States electric grid was primarily designed to transport electricity from central station power plants to end-use customers. But with rapid growth of distributed energy resources such as solar, customers are increasingly taking charge of their own energy. Today's electric grid must allow distributed energy technologies to flourish and provide reliable, low-cost power for consumers. Distributed energy resources, like solar, can also provide power where it is needed most and help avoid investments that a utility would otherwise need to make.

This series explores the elements of electric grid modernization, compares the ways in which two leading states are tackling these issues, and discusses how these efforts are creating new opportunities for solar power. Grid modernization efforts in states present significant risks and opportunities for solar. These efforts will determine how much new solar and other distributed energy resources can interconnect to the grid, identify areas where solar can provide grid services in lieu of utility investments, and in some states, will shape the future of net energy metering.

OPENING THE BLACK BOX: UNDERSTANDING THE CURRENT PRACTICE OF DISTRIBUTION PLANNING & OPERATIONS

Distribution system planning is the process utilities undertake to evaluate their system needs based on forecasting demand, anticipating load shapes, and considering the tools available to them to meet system needs. The process includes two overlapping cycles: a multi-year review and funding cycle in utility general rate cases before a public utilities commission, and an annual planning process undertaken by utility distribution engineers. The former is an arcane regulatory process with some outside input from intervening parties, and the latter has been the sole purview of the utility.

Utilities upgrade their distribution grids based on forecast loads and replacement of aging equipment. Utilities annually review their distribution systems against load forecasts to identify areas where distribution system functioning may be challenged by new loads. They also use an ongoing asset management process to ensure that equipment, such as wooden poles, capacitor banks, and transformers, are replaced as they reach the end of their useful lives.

As part of the planning process, utilities evaluate whether an issue can be addressed by reconfiguring their distribution system. This reconfiguration involves shifting load through switches in the distribution system, moving load served by a substation and feeder to another feeder potentially served by another substation. If reconfiguration is insufficient to address the forecast need, the utility will plan investments in new infrastructure, such as substation upgrades, replacement of capacitor banks, or reconductoring of a feeder. Over the course of an annual planning cycle some investment needs will fall away while others will emerge as new system conditions arise.

With the advent of distributed energy resources, the basic tenets of this process remain intact. However, customers are not simply passive loads. Rather they increasingly have distributed energy resources. Where customers adopt these resources and how they are operated could mean substantially different utility needs in specific locations of the distribution grid over time. As distributed energy resources become more widespread distribution planning must move from simply planning, in a deterministic manner, based on forecast loads, to planning that is based on scenarios of distributed energy resource adoption and includes processes for guiding distributed energy resources to provide alternatives ("non-wire alternatives") to traditional utility investments.

DATA IS CRITICAL TO MODERNIZING DISTRIBUTION SYSTEM PLANNING

Enabling the distribution grid to readily incorporate distributed energy resources, and leverage their capabilities, begins with data. Efforts to change distribution planning and operations are, at their core, exercises in looking at the constraints on the distribution system. Will a new distributed solar system drive voltage beyond accepted limits? Will a new shopping center and housing development require a substation upgrade? The equipment that comprises the distribution system, along with the distribution grid's configuration, define what the distribution grid is capable of handling in terms of load and generation and where it might need to be upgraded.

The various analyses that states are pursuing in grid modernization proceedings are dictated by these grid constraints: 1) hosting capacity is a reflection of distribution grid constraints to accommodate new generation or load;[1] 2) locational value of distributed energy resources is based on the value of avoiding distribution grid upgrades needed for reliability;[2] and 3) non-wires alternatives are pursued in lieu of the identified upgrades underpinning locational values.

Given the importance of understanding the underlying grid needs that drive hosting capacity analyses and locational values, transparency is critical. If the cost-effectiveness of distributed energy resources, and/or their compensation, is going to be dictated by the cost of the needs they are offsetting, there is a reasonable expectation that those costs be publicly available.

Greater data transparency, and non-utility solutions for meeting grid needs, also provide a new opportunity to address an old problem of ensuring that utility expenditures are just and reasonable. To understand distribution system operations today, regulators, ratepayer advocates, and solar companies work through arcane quasi-legal processes to pull what data they can from the utilities using discovery requests, poring over utility filings, and carefully analyzing utility rate case testimony and exhibits. Further, utilities often provide these data in cumbersome formats such as locked spreadsheets or PDF files. While policymakers and interested stakeholders must use this information to determine whether utility investments in the electric grid are "prudent and reasonable," they must also rely on this information when considering methods of modernizing our grid.

To achieve the needed level of data access, regulators must begin considering and implementing new data rules that allow for reasonable access to data about distribution system capabilities and needs. These data include the needs the system has (e.g., capacity, voltage issues, reliability, resiliency, etc.), the scale of that need (e.g., MW, kVAR) and the underlying causes of those needs.[3]

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[1] The next paper in this series will examine developing better hosting capacity analysis.

[2] Other elements of DER locational value include the cumulatively avoided cost of energy and capacity, as well as cumulatively avoided transmission upgrade and maintenance costs.

[3] An excellent resource for understanding what types of data are needed is "Unlocking Grid Data: Enabling Data Access and Transparency to Drive Innovation in the Electric Grid," a white paper jointly authored by TechNet, SunSpec Alliance, and DBL Partners.

These data should be provided in a machine-readable format so that non-utility parties can use modern data analytics to evaluate utility needs and utility investment proposals, and identify areas where ratepayer savings can be realized by bringing distributed energy solutions to bear instead of more costly utility investments.

While reasonable protections must be made for customer privacy and security, protections have been defined to address concerns. Utilities should be specific about any unaddressed privacy or security concerns they believe exist. But such concerns should not be used as a rationale when the underlying concern is a reduction in utility capital expenditure that may result from better insights into utility distribution investment needs and potential third-party alternatives.

IMPROVEMENTS IN DISTRIBUTION PLANNING UNDERPINS NEW METHODS OF VALUATION AND TOOLS FOR INTERCONNCTION

Improved distribution planning yields data that underpins core products of grid modernization proceedings: Locational valuation, hosting capacity analyses, and non-wires alternative opportunities. Outlined below are ways that improved distribution planning provides the inputs to these grid modernization products.

1. Determining Locational Values

Historically, cost benefit analyses used for distributed energy resource programs, such as net-metering, have determined values for avoiding transmission and distribution that are averaged across a utility system. In reality, the value of distributed energy resources varies by location and what needs are driving utility investments. In some places, there may be a need for an expensive upgrade; in other locations, no forecast investments will be needed. Ensuring that all investments that could potentially be deferred or avoided by distributed energy resources are captured and valued requires transparency about distribution system needs, their drivers, and the costs of the utility investments needed to meet those needs. Short of these values it will not be clear to stakeholders whether these locational values are accurate and, therefore, if cost-effectiveness evaluations are fair.

> ***To achieve the needed level of data access, regulators must begin considering and implementing new data rules that allow for reasonable access to data about distribution system capabilities and needs***

2. Identifying Non-Wires Alternatives

Just as the type of utility distribution need, and the cost of the utility investment required to address that need, drive locational value, so too do those needs create the opportunity for non-wires alternatives (i.e., distributed energy resource alternatives to utility investments). Transparency on data about needs on the distribution system can ensure that distributed energy resource providers are afforded the opportunity to identify all opportunities where they may be able to provide more cost-effective solutions than a utility investment.

3. Making Interconnection Faster & Less Costly

Through power flow modeling, utilities use data about the equipment on- and configuration of- their distribution system to determine where upgrades are needed for their distribution systems due to load. The same underlying distribution grid data and power flow modeling can be used to identify how much additional distributed generation (or load, such as electric vehicle fast charging) can be interconnected to the utilities' distribution system. Transparency of these limitations both through hosting capacity maps, and the data underlying these maps, can help reduce interconnection costs and uncertainty for distributed energy resource developers.

Distribution Operations: The next frontier beyond improved planning

In addition to an evolving paradigm and process for grid planning there is discussion of new operational models. As new telecommunications technologies are developed and deployed by utilities, the ability of a utility to remotely monitor conditions and control equipment on the distribution system has increased. Telecommunications equipment ("SCADA") has allowed utilities to remotely monitor and control major equipment like substations and switches. Smart meters have provided far more insight into conditions at individual customer locations. With the advent of distributed energy resources there is a question of whether further telemetry and controls are needed to monitor distribution grid conditions that may be altered by distributed energy resources.

Utilities are proposing new equipment and software to monitor their distribution systems at a more granular level and potentially to control distributed energy resources directly or through aggregators. But the natural tendency of utility planners and operators to desire control over equipment on the grid should be resisted in favor of providing opportunities for customer devices and third party IT infrastructure, using the internet, to demonstrate their full capabilities to provide the necessary services at lower costs. Using existing third party equipment will deliver more value to customers than allowing utilities to make potentially expensive new investments and passing on those costs to ratepayers.

Going beyond new technology changes, operations of the distribution grid should change the role the utility plays as a distribution system operator. Utility operations could transition from a distribution system operator (DSO) where grid conditions are managed through utility operation of traditional infrastructure to an independent distribution system operator (IDSO) where a financially disinterested entity can orchestrate the operation of resources, both utility and third-party owned, to meet distribution system needs. For example, in New York the utilities have been directed to establish a distribution system platform provider (DSP) for their service territory. The DSP will be operated by the utility and generate revenue through the establishment of to-be-determined platform service fees, but remain functionally separated by a firewall from the utility's traditional role as a distribution company.

As distributed energy resources meet customer needs, local distribution needs, and wholesale market needs there will also need to be a capability for the DSO or IDSO to better communicate with the bulk transmission system operator to understand how transmission-level dispatches of DERs will impact locations on the distribution grid and the transmission system.

LEADING STATE EFFORTS TO REFORM UTILITY DISTRIBUTION PLANNING

1. California

In response to Assembly Bill 327, California's major utilities have filed distribution resources plans (DRPs). The methodologies of these plans have been under further development in the Distribution Resources Planning (DRP) proceeding and Integrated Distributed Energy Resources (IDER) proceeding.

The DRP proceeding has evaluated geographically-granular forecasts of distributed energy resources down to the feeder-level. These forecasts will inform a revised distribution planning process, potentially including a Grid Needs Assessment[4] which will outline all needs, both for traditional distribution grid upgrades as well as any grid modernization to accommodate DER.

This Grid Needs Assessment will provide the inputs to a deferral framework, which will identify projects that are deferrable or entirely avoidable through the deployment of distributed energy resources. This assessment, in turn, will determine locational net benefits in the locational net benefit analysis.

> ***Distribution planning must become more dynamic, and the methods applied must adapt to and account for the changing environment.***
> ***-NY PSC***

[4] CPUC Energy Division Staff "Staff Whitepaper on Grid Modernization" (April 2017) http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M186/K580/186580403.PDF.

Data access has been an area of disagreement between the utilities and distributed energy resource providers. The Commission has established rules for customer privacy, which include aggregation of customer data to ensure their individual usage is not publicly disclosed. The utilities have argued, however, that though much of this data may not result in privacy or security concerns it is “market sensitive,” meaning that if they disclosed the costs of various needs on the distribution system any non-wires alternative solicitation would result in distributed energy resource companies bidding to the utilities’ cost. This is an illogical outcome, but the argument has heretofore meant that only indicative values are available for the locational value of distributed energy resources.

Distribution system operations are being discussed in several forums. Southern California Edison’s current recent general rate case[5] is exploring new tools for operating the distribution system, with one of their rationales being operation at high penetrations of distributed energy resources. Interconnection rules have established communications standards and pathways for the utilities to communicate with distributed energy resources directly.[6] Ongoing conversations between the California Independent System Operator (CAISO) and the state’s utilities are seeking to determine how distribution utilities and the ISO can better coordinate as distributed energy resources participate in the ISO’s markets.[7]

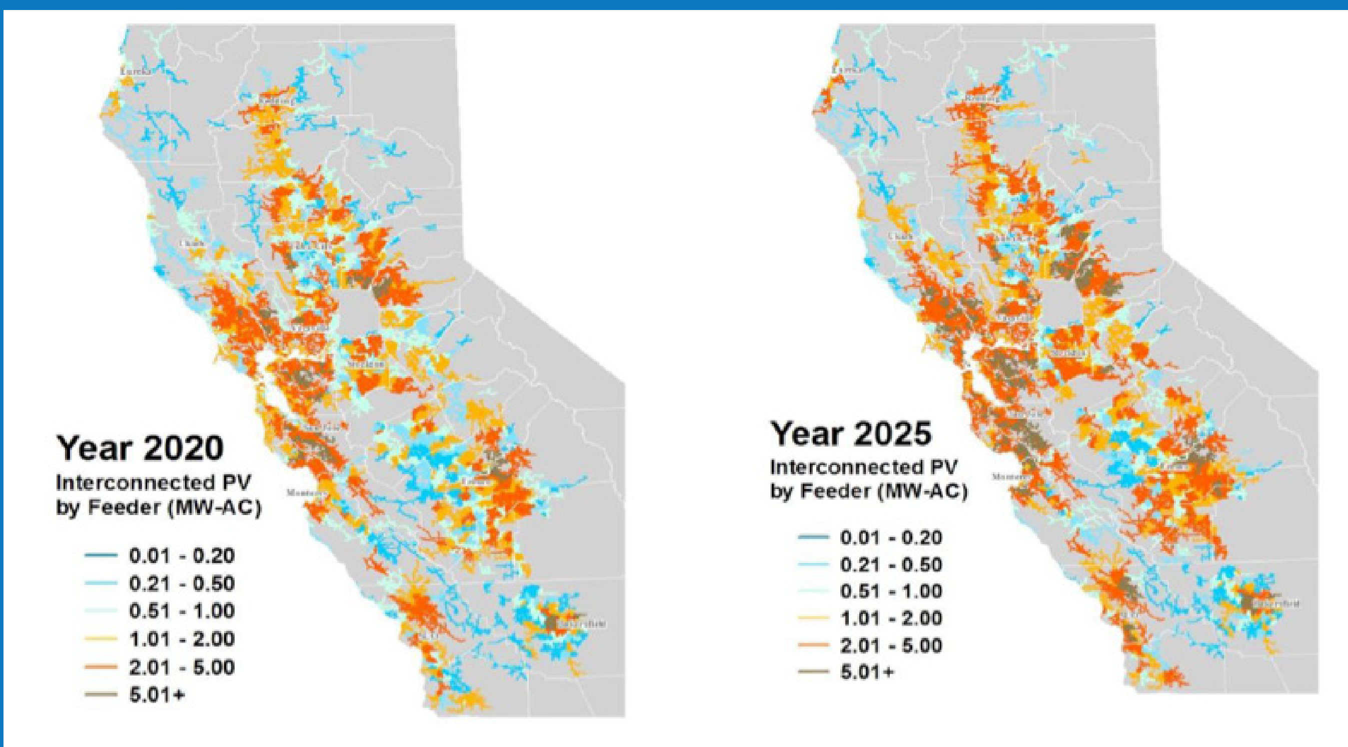

Figure 1: Pacific Gas & Electric Distributed PV Generation Forecast

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[5] “Test Year 2018 General Rate Case Application of Southern California Edison” California Public Utilities Commission docket A.16-09-001.

[6] Each utility has filed advice letters which will, beginning in March 2018 or 9 months following the establishment of relevant SunSpec standards, will require smart inverters to be capable of three different communications channels.

[7] For a discussion of these issues see More Than Smart, “Coordination of Transmission and Distribution Operations in a High Distributed Energy Resource Electric Grid” (June 2017) http://morethansmart.org/wp-content/uploads/2017/06/MTS_CoordinationTransmissionReport.pdf

2. New York

The New York Public Service Commission (PSC) also directed the utilities to file plans to better identify and integrate distributed energy as a major means of meeting distribution utility infrastructure and operational needs.[8] The PSC stated, "Distribution planning must become more dynamic, and the methods applied must adapt to and account for the changing environment."[9] The PSC identified two key areas of advanced planning: integrated system planning and hosting capacity analysis.

CONCLUSION

Utility distribution planning has begun to move from a focus on meeting passive loads to anticipating distributed energy resources, both in terms of how many DERs can be expected on the system and where these resources are likely to be located. To benefit ratepayers and unlock the full value of a modernized grid, updated distribution planning must leverage DERs, such as solar, to meet distribution needs where they may have traditionally used utility installed, owned, and operated equipment. Some states are leading the way toward reforming distribution planning, but much more work must be done. A key for regulators will be to guard against over-investment by utilities under the rationale of enabling distributed energy resources in the marketplace. Distribution planning done correctly will create opportunities for solar firms and other distributed energy resources, better value for customers, and help state's meet their energy and economic development goals.

[8] See Market Design and Platform Technology Report at 50

[9] See DSIP Guidance at 9

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SEPTEMBER 2017

HOSTING CAPACITY: USING INCREASED TRANSPARENCY OF GRID CONSTRAINTS TO ACCELERATE INTERCONNECTION PROCESSES

The third in SEIA's *Improving Opportunities for Solar Through Grid Modernization* Whitepaper Series

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EXECUTIVE SUMMARY

Built during the last century, the United States electric grid was primarily designed to transport electricity from large central station power plants to end-use customers. But with rapid growth of distributed energy resources, such as solar, resulting from falling costs and technological advances, customers are increasingly taking charge of their own energy. These resources offer the promise of a more innovative, economic, and cleaner electric grid.

In recognition of the growing role, value, and opportunity of distributed energy resources, a number of states across the country are looking at how distribution system planning, operations, and investment must change. This paper series examines the potential changes being considered and the opportunities for solar and other distributed energy resources.

This paper is the third in SEIA's series on grid modernization and focuses on improving interconnection with hosting capacity analyses. As with the rest of the papers in this series, the experiences of two leading states, California and New York, are examined.

ABOUT THIS WHITEPAPER SERIES

This series of SEIA policy briefs takes an in-depth look at state-level efforts to modernize the electric utility grid. Built during the last century, the United States electric grid was primarily designed to transport electricity from central station power plants to end-use customers. But with rapid growth of distributed energy resources such as solar, customers are increasingly taking charge of their own energy. Today's electric grid must allow distributed energy technologies to flourish and provide reliable, low-cost power for consumers. Distributed energy resources, like solar, can also provide power where it is needed most and help avoid investments that a utility would otherwise need to make.

This series explores the elements of electric grid modernization, compares the ways in which two leading states are tackling these issues, and discusses how these efforts are creating new opportunities for solar power. Grid modernization efforts in states present significant risks and opportunities for solar. These efforts will determine how much new solar and other distributed energy resources can interconnect to the grid, identify areas where solar can provide grid services in lieu of utility investments, and in some states, will shape the future of net energy metering.

WHAT IS HOSTING CAPACITY?

One concept that has garnered considerable attention is the idea of developing better assessments of DER "hosting capacity" as part of the planning process. Hosting capacity is the amount of DERs that the electric distribution system can reliably accommodate without significant grid upgrades.[1] In conducting a thorough hosting capacity analysis, utilities consider voltage/power quality constraints, thermal constraints, protection limits, safety, and overall reliability to arrive at a capacity (kW, MW) of new generation or load which can be accommodated at a specific location on a distribution circuit.

Hosting capacity depends heavily on location. It is unique to specific feeders and is time varying. Given that customer needs are always changing, a hosting capacity analysis conducted today may yield different results than an analysis prepared five years from now. In general, carefully crafted hosting capacity analysis can give DER developers insight into where on the grid DERs can interconnect and potentially, on a forecast basis, where utility upgrades may be needed in anticipation of DER growth.

RULES OF THUMB NO LONGER WORK FOR INTERCONNECTION

Historically, general "rules of thumb" have been used to provide a preliminary estimation of available capacity for interconnecting new distributed generation. These conservative approximations often act as a significant and unnecessary barrier to many projects. These rules of thumb include generation as a percentage of peak load on a circuit or a percentage of minimum daily load. For example, since the late 1990s California's interconnection procedures for small generators (Rule 21) has established a threshold for supplemental interconnection review of 15% of peak demand. If the total installed distributed generation capacity on a line segment exceeds 15% of the line section peak annual load, further analysis must be undertaken before the project is approved. This standard has become common around the United States.

As an alternative rule of thumb, a percentage of minimum daytime load has often been used as a threshold, since the minimum load during the time when solar is producing is most relevant to whether the generation will cause challenges for the distribution system by producing energy flows back towards the substation.

Both installed capacity as a percentage of peak load or minimum daily load are inaccurate. Indeed, research from the Sandia National Labs have found no correlation between peak load and hosting capacity.[2] Instead, accurate hosting capacity analysis requires that the characteristics of an individual line segment in a distribution system are assessed to ensure that a potential solar generator or other distributed energy resources, such as combined heat and power generator or electric vehicle charging, do not result in violations of power quality/voltage, safety, protection, thermal or safety/reliability limits.

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[1] New York State Public Service Commission, "Order on Distributed System Implementation Plan Filings" at 10, March 9, 2017, available at: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={F67F8860-0BD8-4D0F-80E7-A8F10563BBA2}

[2] Matthew Reno and Robert Broderick, "Statistical Analysis of Feeder and Locational PV Hosting Capacity for 216 Feeders", Sandia National Laboratories http://energy.sandia.gov/wp-content/uploads/dlm_uploads/2016/06/SAND2015-9712C_PES_GM-HostingCapacities.pdf

HOSTING CAPACITY ANALYSIS: REDUCING UNCERTAINTY AND INCREASING SPEED BY GETTING BEYOND RULES OF THUMB

The process of interconnecting a solar system requires assurances that the operation of the system will not impair the safe, reliable functioning of the distribution and transmission system. For larger DERs, this requires engineering studies which take significant time and can add substantial, and potentially unnecessary, expenses for project developers to upgrade the distribution system to accommodate the connecting DER.

Currently, when generators fail certain tests in the interconnection process they must undergo an interconnection study process. These tests often include the previously mentioned rule of thumb limits as an initial screen. In the subsequent interconnection study process, power flow modeling is performed by utility engineers to ensure that the generator will not violate any of the limits to power quality, safety, etc. In many cases the generator may fail the initial "rule of thumb" screens but ultimately learn that the distribution grid can easily accommodate their generator. However, even when this happens substantial costs are borne by the developer and customer in foregone bill savings and costs associated with project development delays. In some cases, large distribution grid upgrades can be identified which make the project uneconomical. News of these costs come after the solar company has invested substantial cost in acquiring the customer and designing the project.

A hosting capacity analysis uses the engineer's tools proactively to determine an amount of capacity that can be interconnected on any individual line segment. By using these power modeling tools to generate hosting capacity we can replace rules-of-thumb, like minimum daily load, and improve the interconnection process. Indeed, as we have shown, work is underway in several states to generate maps which have up-to-date amounts (in megawatts) of available integration hosting capacity.

Case Study: Rule-of-Thumb Hosting Limits Shut Down Hawaii

In 2013, Hawaii Electric Company (HECO) placed a moratorium on new solar interconnections on line segments where solar capacity exceeded 120% of minimum daily load. Following testing by the National Renewable Energy Laboratory, in collaboration with SolarCity and HECO, the limit was raised to 250% of minimum daily load with new systems required to install smart inverters. The market was able to reopen but only after a severe interruption based on an overly conservative rule-of-thumb interconnection test.

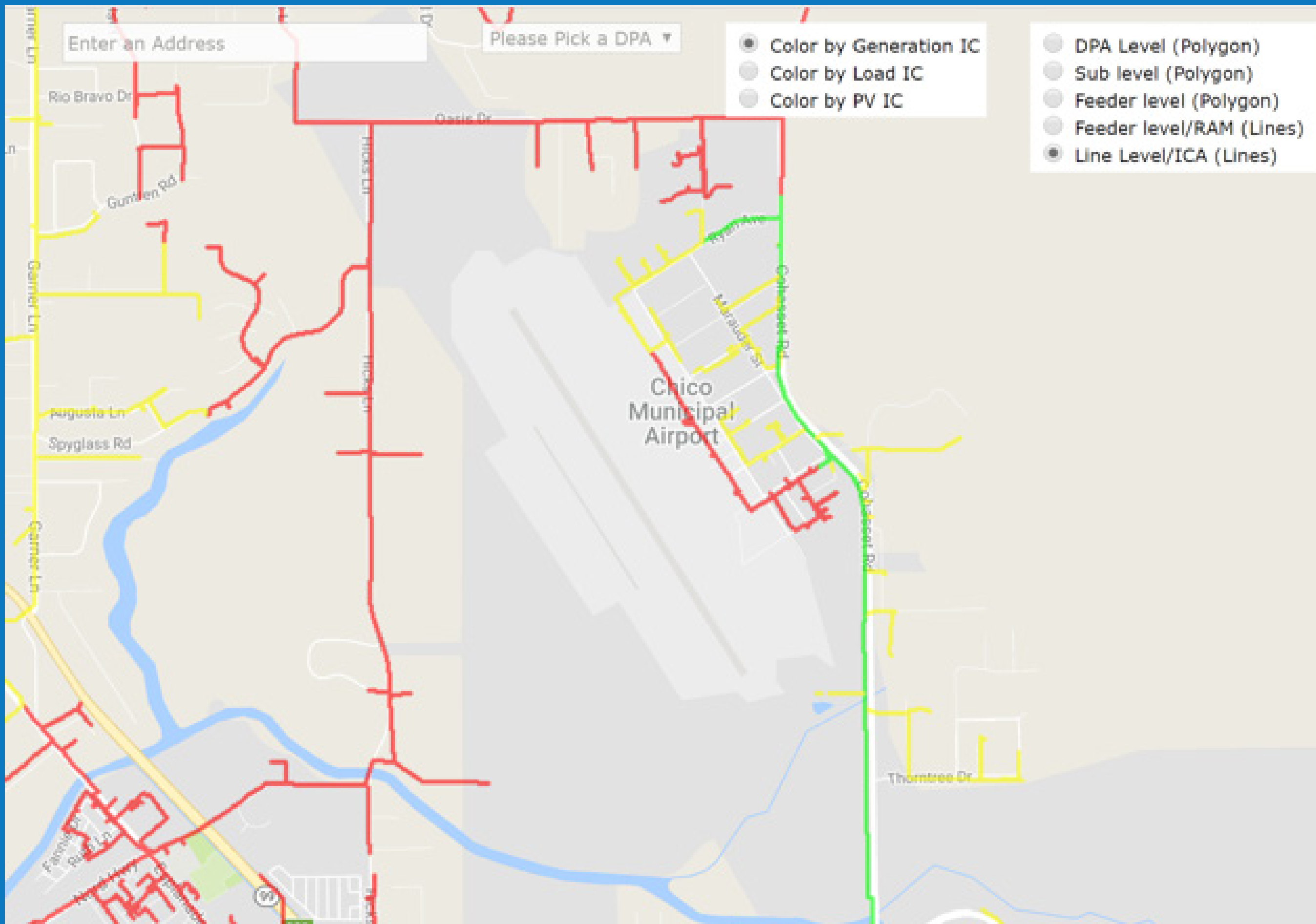

Figure 1: Snapshot of Pacific Gas & Electric Hosting Capacity Map[3]

NEW OPPORTUNITIES CREATED BY HOSTING CAPACITY

Hosting capacity analysis creates new opportunities for greater cost certainty and speed in interconnection. Hosting capacity analysis could also help developers plan their sales to avoid trying to interconnect in areas where hosting capacity is limited. However, hosting capacity also creates opportunities for identifying creative solutions for integrating a DER system that may not otherwise fit within available hosting capacity. Currently accommodating a distributed solar system while avoiding distribution system upgrades may be possible through a back-and-forth discussion between the developer and utility engineers modeling the distribution grid, but that is a drawn out process that leads to project delays. By providing a granular understanding of hosting capacity analysis - which hours are challenging and what conditions, such as voltage, are limitations - project developers can provide solutions to address that limitation without utility upgrades.

[3] Pacific Gas & Electric hosting capacity map, available at https://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/PVRFO/DemoAMap/DemoA.html

A. Leveraging the Capabilities of Smart Inverters

Historically, inverters have had the humble role of converting direct current from solar systems into alternating current which could be distributed within a building or exported back to the distribution grid. However, the evolution of smart inverter technology and standards are increasing their capability. Starting in September 2017, all new solar systems applying for interconnection in California will need to have inverters enabled to provide some relatively basic grid support functions that inverters can do autonomously, including the ability to “ride-through” voltage and frequency disturbances rather than tripping off as current inverters do.[4] These rules will soon become standard features of interconnection in more states around the country as the IEEE 1547 interconnection standard is updated.

The updated IEEE standard is expected, by the end of the year, to require providing reactive power when voltage conditions go outside of an acceptable range. This new requirement in the standard should expand hosting capacity in all locations where inverter-based distributed energy resources are installed. Figure 2 below from the Electric Power Research Institute shows how Volt/VAR control can enhance hosting capacity.

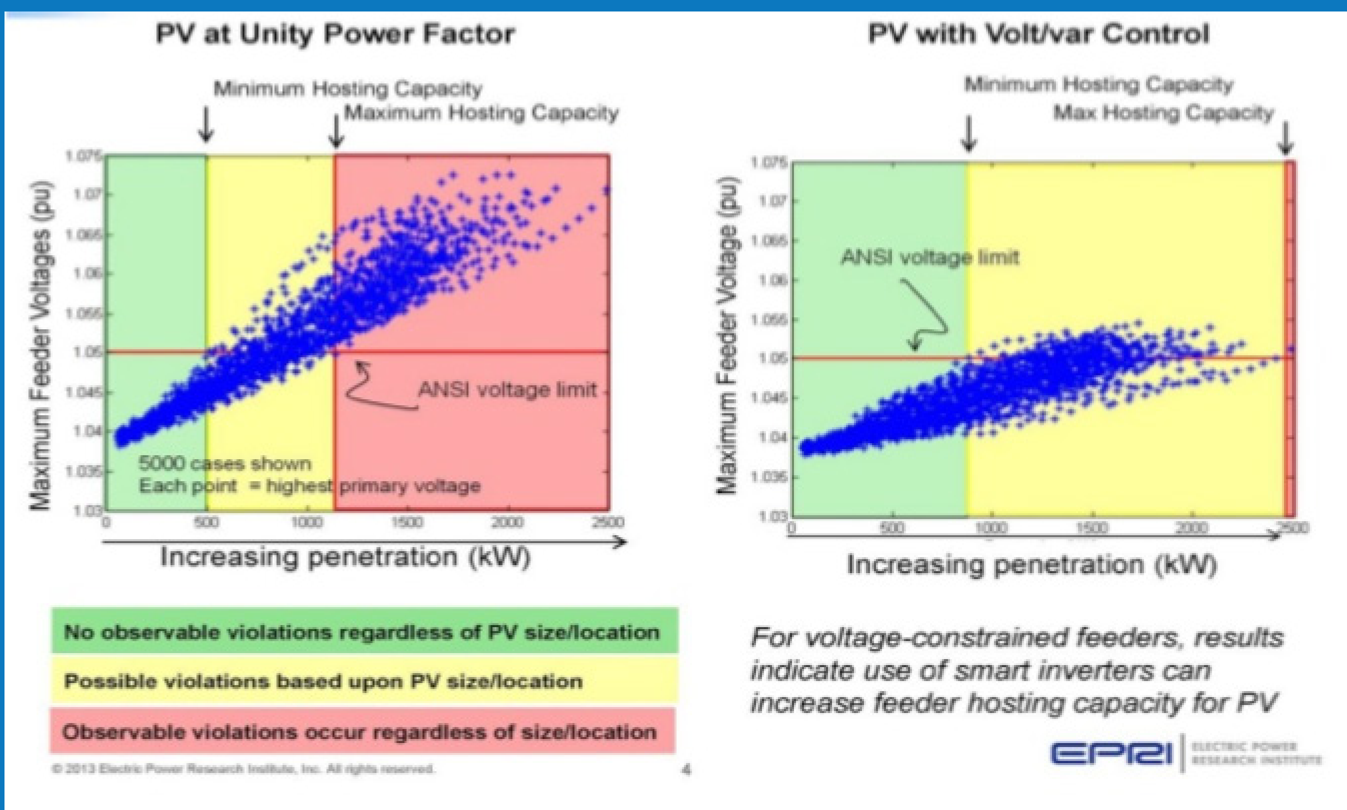

Figure 2: Improving Hosting Capacity Through Inverters (Volt/VAR control)[5]

[4] Hawaii has adopted similar rules. Rule 14H

[5] Electric Power Research Institute as presented in May 6th, 2016 Presentation by Rachel Peterson, Advisor to California Public Utilities Commissioner Michael Florio, available at: https://www.slideshare.net/sandiaecis/wl-1cpuc-for-epri-sandia-modeling-workshop-6-may-2014

B. Enhancing Hosting Capacity Through Storage and System Configuration

In the past, interconnection studies would make limiting assumptions about system operations. For example, maximum potential solar production from a system might be compared to minimum daily load which occurs during spring or fall months when solar production is reduced. Knowing that minimum limitation, such as voltage on low-load days in shoulder months, could allow for a developer to modify their project to avoid distribution upgrades. For example, inverter settings could be set to limit real power output during these shoulder months or battery storage could be added to a solar system to avoid exports at these problematic hours. In California, the utilities have created "agnostic" hosting capacity curves which can allow for a myriad of project generation or load curves, better reflecting different DER configurations (e.g., solar plus storage) and providing for creative solutions to interconnecting projects where there are hosting capacity limitations.

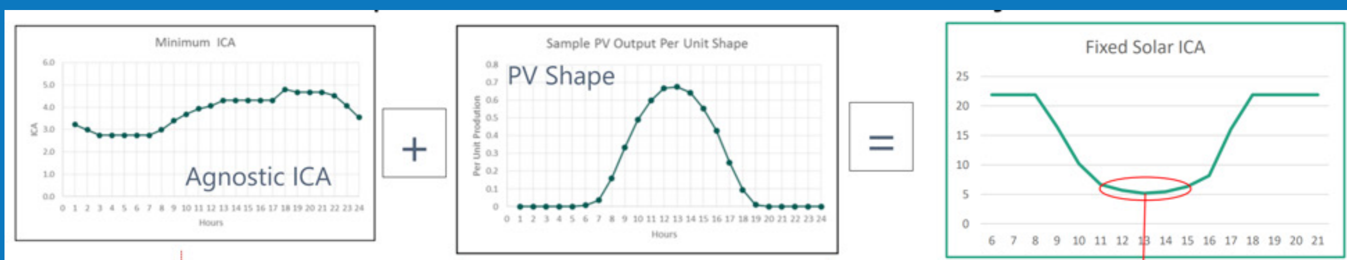

Figure 3: Identifying Hosting Capacity[6]

THE INTEGRATION CAPACITY ANALYSIS: HOSTING CAPACITY IN CALIFORNIA

California's IOUs are recognized for having some of the fastest interconnection processes in the country, largely as a result of automating interconnection application processes. However, larger projects can be delayed based on interconnection screens. California's interconnection process, Rule 21, includes rule-of-thumb limits in its Fastrak interconnection process. Often projects will fail these screens and have to undergo an interconnection study. In order to limit uncertainty for the developers, a 2016 Commission decision (D.16-06-052) created a requirement for upgrades which might be identified and bounded the costs which developers would ultimately need to pay if costs exceeded those limits.

Simultaneous to the Commission's efforts to bound the costs of unexpected results from interconnection studies, the Commission and utilities have been working on hosting capacity analyses (known as "Integration Capacity Analyses" or "ICA"). California's three largest utilities completed ICA pilots at the end of 2016 and are currently working with a working group to refine their methodology.

[6] Figure from Joint Utility presentation at Distribution Resources Planning Working Group meeting July 7, 2017, available at: http://drpwg.org/wp-content/uploads/2016/07/07.07.17-ICA-LNBA-WG-presentation-deck.pdf

The Commission is expected to adopt the ICA this year and has opened a proceeding to revise the interconnection process.[7] The ICA should allow for the replacement of several screens in the fast track interconnection process and hopefully allow for creative project design opportunities to avoid distribution upgrades where there may be a lack of hosting capacity.

NEW YORK: A FOUR STAGE PROCESS TO DEVELOP HOSTING CAPACITY MAPS

In New York, the Public Service Commission (PSC) approved a four-stage process for improving hosting capacity analysis. While there is still significant work to be done to implement this process, the four phases are as follows:

- Stage 1: Use of Red Zone maps to identify the layout of overhead circuits and indicated whether the interconnection of certain sized DG would have a higher or lower cost;
- Stage 2: Calculate hosting capacities using the Distribution Resource Integration and Value Estimation (DRIVE) tool developed by the Electric Power Research Institute (EPRI). This tool is based on circuit models and therefore requires circuit analyses.
- Stage 3: Development of "heat" maps that represent capacity ranges using color schemes consistent across utilities. The hosting capacity ranges will be based on the circuit characteristics and will provide information about currently interconnected DERs, as well as DERs in the interconnection queue. The data will be updated regularly by the utilities.
- Stage 4: Hosting capacity data to be further refined at more granular levels, such as incorporating host capacity data on the sub-feeder level and the locational value that interconnection of DERs would have on a particular feeder and/or substation.

Finally, the utilities have proposed ways in which hosting capacity can be increased by resolving voltage, thermal, and protection violations that limit additional DERs from interconnecting. Solutions include grid-side measures, operational measures, and customer-sided solutions. While questions remain about the New York utilities' ability to meet the timeframes required by the PSC for completing these analyses, the Commission's recognition that new processes must be put in place for determining an accurate hosting capacity is a small step in the right direction.

CONCLUSION

As distributed energy resources proliferate, ensuring that interconnection delays and costs do not stymie their deployment is critical. Improved utility distribution system planning tools and processes allow for an accurate assessment of how much new distributed energy resource capacity can be interconnected at any point in the distribution grid. As leading states are close to implementing hosting capacity analyses system wide we should begin to see the benefits in those states and have lessons for other states to follow.

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[7] California Public Utilities Commission, Order Instituting Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21, Rulemaking 17-07-007 https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO

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JANUARY 2018

GETTING MORE GRANULAR:
HOW VALUE OF LOCATION AND TIME MAY CHANGE COMPENSATION FOR DISTRIBUTED ENERGY RESOURCES

The fourth in SEIA's *Improving Opportunities for Solar Through Grid Modernization* Whitepaper Series

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EXECUTIVE SUMMARY

Built during the last century, the United States electric grid was primarily designed to transport electricity from large central station power plants to end-use customers. But with rapid growth of distributed energy resources (DER) resulting from falling costs and technological advances, customers are increasingly taking charge of their own energy. These resources offer the promise of a more innovative, economic, and cleaner electric grid.

DER, such as solar power, will play an important role providing power and grid services where they are needed most. To reach this goal, however, distribution grid planning must evolve to allow more transparency into system needs, enable more robust data exchange between utilities and DER providers, and include DER as a standard component of utility load forecasts.

This paper, the fourth in SEIA's series on grid modernization, focuses on the ways in which the location of a DER can provide various grid benefits and may lead to changes in DER compensation. As with the rest of the papers in this series, the experiences of two leading states, California and New York, are examined. These two states are in the process of conducting extensive work examining new locational values and location-based tariffs and can serve as models for other states that are considering similar policies.

ABOUT THIS WHITEPAPER SERIES

This series of SEIA policy briefs takes an in-depth look at state-level efforts to modernize the electric utility grid. Built during the last century, the United States electric grid was primarily designed to transport electricity from central station power plants to end-use customers. But with rapid growth of distributed energy resources such as solar, customers are increasingly taking charge of their own energy. Today's electric grid must allow distributed energy technologies to flourish and provide reliable, low-cost power for consumers. Distributed energy resources, like solar, can also provide power where it is needed most and help avoid investments that a utility would otherwise need to make.

This series explores the elements of electric grid modernization, compares the ways in which two leading states are tackling these issues, and discusses how these efforts are creating new opportunities for solar power. Grid modernization efforts in states present significant risks and opportunities for solar. These efforts will determine how much new solar and other distributed energy resources can interconnect to the grid, identify areas where solar can provide grid services in lieu of utility investments, and in some states, will shape the future of net energy metering.

VALUING DISTRIBUTED ENERGY RESOURCES: MORE GRANULARITY ON TIME AND LOCATION

Electricity supply and demand must be balanced on an almost instantaneous basis at all times and in all locations of the power grid. To accomplish this, utilities must plan their systems around the hours when demand is forecasted to be highest and ensure that they have enough capacity to meet this demand. To meet reliability requirements, utilities must also maintain an additional amount of capacity beyond this peak load as a reserve margin. Each part of the utility system, whether the total capacity of the power plants, the amount and size of transmission lines, or the equipment on a distribution circuit, must be designed to provide reliable service during the most challenging times that equipment is expected to face. DER such as solar PV can help avoid or delay investment in the grid infrastructure required to meet these needs by reducing load at the exact time when utility systems are most challenged. These resources can also be actively targeted to meet a distribution system need, through a solicitation, tariff or other mechanism.

Defining Locational Value

As part of their annual distribution planning process, utilities look closely at expected needs on the distribution grid in the following ten years. During this process, utility distribution engineers consider localized load forecasts based on demographic trends, such as population growth and household size, as well as planned construction, such as new housing communities and shopping centers. Based on current conditions and its forecast, the utility will determine if and where there are emerging or anticipated deficiencies for capacity or power quality. For example, expected home construction in an area may lead to projected load growth that requires replacing wiring on a distribution circuit, adding capacity to a substation, or some other upgrade. These projections are based both on the location of deficiencies as well as the specific time of day driving those needs. For example, certain circuits may need additional capacity to meet planned loads on hot summer afternoons, while other circuits may have high winter morning heating loads that must be addressed.

Once the utility understands its local capacity needs, the cost of the project – and thus the value of avoiding the project – can be determined. The cost of the project or projects needed to address an identified shortcoming should be based on the incremental cost of adding a unit of capacity to that area, for example $/kW-year. This is called the "marginal cost of capacity" as it reflects the cost to add new capacity, not the cost of the capacity already on the grid. The locational value of a DER system can be determined based on the contribution the resource makes to meeting that need, whether through energy, capacity, or reactive power produced during the hours when there is a need in that location. For example, if a set of circuits that peak in late August hours are driving the need for a multi-million-dollar substation, the locational value for a DER in this area would be equal to the marginal cost of adding that new substation capacity and any other needs on the distribution grid driven by those peak hours.

Getting Time-Value Right: Time of Use Rates

Locational value is based both on where distribution grid upgrades are needed as well as the hours that are causing the need in that location. However, other factors that drive the need for new power plants or transmission expansion projects also vary across times. Properly designed time-of-use rates can be a way to align the behavior of all utility customers – both with and without solar – to the needs of the grid. TOU rates may also be designed to support new technologies such as energy storage. For example, SEIA has proposed a suite of solar-plus-storage TOU rates in a recent Pacific Gas & Electric rate case.[1]

Defining Locational "Hot Spots"

Figure 1: New York Local System Relief Value Map

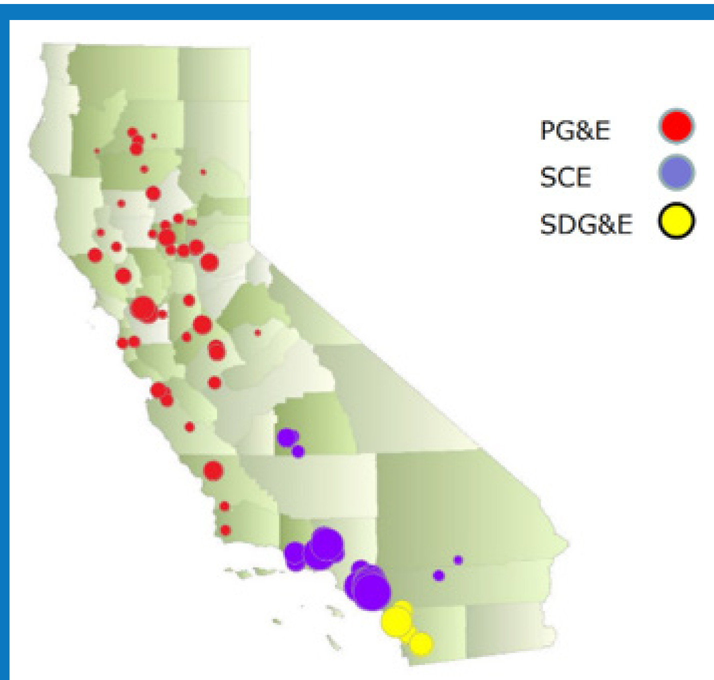

Figure 2: California Distribution Cost "Hot Spots"[2]

USING LOCATIONAL VALUE

Locational analysis can be a useful tool in unlocking the additional value that solar can provide to distribution system. Gaining a better understanding of locational value can help guide the placement of DER – including solar – to high value locations, provide the basis for compensation through location-specific utility solicitations or tariffs, and improve the accuracy of DER cost effectiveness evaluations. However, as useful as locational value is in some contexts, it should not necessarily replace other policies such as net metering, especially in emerging markets. Net metering has a demonstrated record of creating strong markets for renewables, and a location-based-variable tariff has yet to be demonstrated anywhere in the US. Only when emerging markets have reached a certain level of maturity should regulators begin the process of considering more location-based compensation frameworks.

[1] Jeff St. John, "California Solar Industry and Utilities Unveil Dueling Solar-Storage Tariffs", Greentech Media (March 17, 2017). Available at: https://www.greentechmedia.com/articles/read/california-solar-industry-utilities-unveil-dueling-solar-storage-tariffs

[2] Snuller Price, Energy and Environmental Economics (E3) Presentation to the New York REV Value Stack Working Group (September 20, 2017). Available at : http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/8a5f3592472a270c8525808800517bdd/$FILE/E3%20VDER%20Workshop%20California%20LNBA.pdf

Guiding DER to High Value Locations

Locational value can be used to guide resources to high value locations. Utilities can create, and should publish maps[3] showing the specific locations of any needs on the distribution system, the specific grid constraints to avoid the need (e.g., high loads during hot late summer afternoons), and the value of the avoidance in terms of dollars per amount of capacity. If a developer knows in advance that there will be a utility solicitation for the identified needs, it can begin seeking customers or project sites in anticipation of the opportunity to bid in its projects.

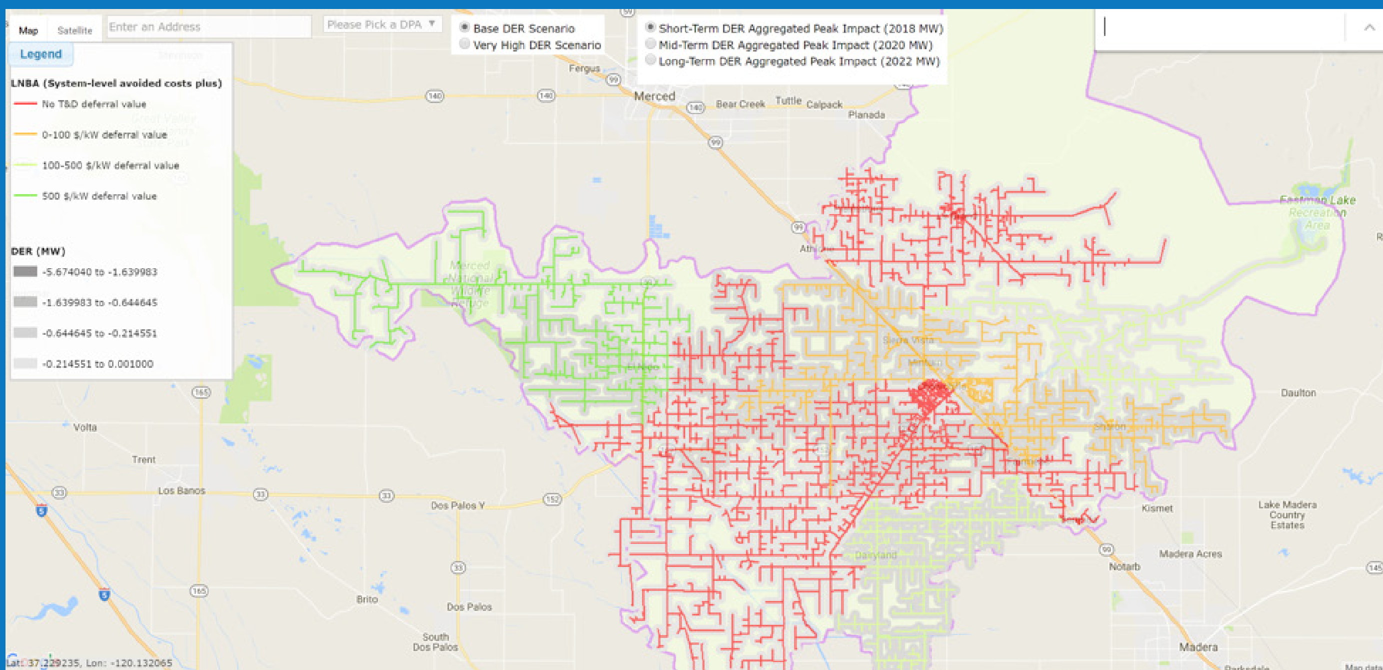

Figure 3: Locational Value Map for a Distribution Planning Area in Pacific Gas & Electric's Service Territory[4]

Providing the Basis for Compensation

In addition to competitive utility solicitations, there are alternative means of providing targeted tariffs, programs or incentives to drive DER to locations to meet identified needs. If identified needs are too small or have too short of a lead time to be met through a competitive solicitation, the utility could have a tariff- or program-based mechanism that can step in on short notice. For example, voltage issues are often very isolated and managed with small utility investments. However, smart inverters are increasingly being deployed widely and can be used to provide voltage management services in the locations where a utility has challenges managing voltage within an acceptable range. In addition, tariffs enable customers of all stripes to adopt solar and other DER, which delivers the generalized grid benefits we discuss, but also ensures that a state's clean energy market grows equitably in a manner that distributes the social, environmental, and economic benefits to all ratepayers. This is an emerging topic and it is expected that California's Integrated Distributed Energy Resources proceeding will explore non-solicitation based sourcing mechanisms.

[3] For example, see Pacific Gas & Electric's demonstration Locational Net Benefit Analysis map. Available at: https://www.pge.com/b2b/energy-supply/wholesaleelectricsuppliersolicitation/PVRFO/DemoBMap/DemoB.html

[4] Screenshot from Pacific Gas & Electric's demonstration Locational Net Benefit Analysis map.

Improving Cost-Effectiveness Evaluations

California's Locational Net Benefit Analysis is a modification of the state's Distributed Energy Resources Avoided Cost (DERAC) calculator. The DERAC is a spreadsheet tool incorporating utility costs that can be avoided by DER and is used to evaluate the cost-effectiveness of all demand-side programs in California, including net metering. The locational net benefit analysis has sought to take state-wide[5] averaged avoided costs for transmission and distribution and unbundle these values into specific sub-categories. The Commission has ordered the utilities to modify the DERAC tool to create a spreadsheet which incorporates locational values for approximately 500 distribution planning areas. While this may, in theory, provide a more precise view of the cost effectiveness of different DER programs, one must be cautious not to overestimate the precision of long-term locational forecasts that underpin these types of tools.

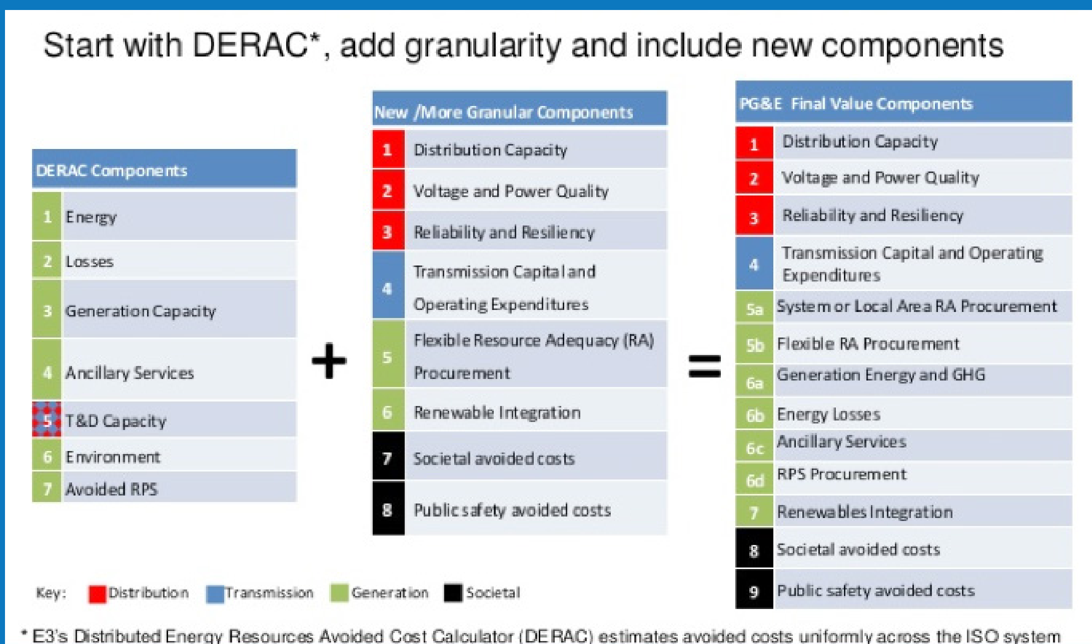

Figure 4: Improving Locational Granularity of Cost-Effectiveness Frameworks[6]

Likewise in New York, to help inform the ongoing Reforming the Energy Vision (REV) effort, the Public Service Commission (PSC) published a Benefit Cost Analysis (BCA) Framework Order[7] (Order) that sets out the standard elements that enable a fair comparison of benefits and costs for a range of utility investment decisions, as well as the development of future tariffs. While not directly taking on the task of identifying locational value for utility planning areas, the Order establishes the categories of value upon which successor tariffs to net metering are based. Further refinement of the detailed methodologies for calculating values was delegated to the utilities through the publication of specific BCA Handbooks.

[5] The term "statewide" is used generally here. In practice, the DERAC tool accounts for the area of the Independent System Operator which accounts for over 80% of the state's load.

[6] Pacific Gas & Electric's Distribution Resources Plan (July 2015). Available at: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5141

[7] New York State Public Service Commission, Order Establishing The Benefit Cost Analysis Framework, Case 14-M-0101 (January 2016). Available at: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={F8C835E1-EDB5-47FF-BD78-73EB5B3B177A}

Modifying or Developing Tariffs

New York and California are examining tariffs where value varies over time and location. As part of its REV initiative, New York is now requiring that large commercial and industrial customers, and community solar customers, use the Value of Distributed Energy Resources tariff. California's "Net Metering 2.0" tariff requires all net metering customers to take service on a time-of-use rate. Both moves are motivated by regulators' intent for DER compensation to better reflect the locational and temporal value that distributed energy resources provide.

New York's Value of Distributed Energy Resources (VDER) Tariff

In March 2017 and in subsequent Orders, the New York PSC approved a new compensation framework to replace net metering with value-based compensation for larger solar projects, including community solar projects.[8] While maintaining net metering for residential customers through 2020, the VDER Orders establish compensation for electricity delivered to the grid on an hourly basis. They base compensation on categories of value making up a "value stack." The components include: the actual value of the energy and capacity, the value of avoided environmental externalities, the value of avoided distribution system costs, the value of avoided distribution costs in specific locations, and a transition value that allows for a gradual shift away from retail rate net metering. But instead of using detailed utility analyses to determine locational value, which in many instances does not yet exist, the PSC approved the use of proxies to stand in for demand reduction and locational values until better methods can be developed. Successor VDER tariffs are expected to refine the way locational values are calculated and there is considerable debate by stakeholders over the proper methods.

California NEM 2.0 and a view towards NEM 3.0

Unlike New York's "top down" approach of using proxies to inform new tariffs for DER, California has taken a "bottom up" approach to grid modernization. It has begun with new processes and methods for leveraging distribution system data for hosting capacity maps, modifying the distribution planning process, and determining locational value. The California Public Utilities Commission's NEM 2.0 decision acknowledges this, stating that while the Commission recognizes that the full value of distributed PV is hard to quantify, the state's grid modernization proceedings should continue to seek to better understand those values. The Commission determined the best course of action is to revisit net metering in 2019 after these proceedings have concluded.[9] Currently the utilities and stakeholders are in the process of developing Locational Net Benefit Analyses for consideration by the Commission. Locational values are expected to be available in maps across the state with full locational values in mid-2019.

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[8] New York Public Service Commission, Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, And Related Matters (Case 15-E-0751), (March 2017). Available at: https://www.nyserda.ny.gov/-/media/NYSun/files/VDER-Implementation-Order.pdf

[9] California Public Utilities Commission, Decision D1601044 - Decision Adopting Successor to Net Energy Metering Tariff (January 28, 2016) pp.58-60. Available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf

PRINCIPLES FOR DEVELOPMENT AND USE OF LOCATIONAL VALUES IN COMPENSATION MECHANISMS

Locational valuation and compensation are emerging areas of utility regulation and DER compensation. Net metering, by contrast, is simple, easy for customers to understand, and is a proven, cost-effective way to achieve solar customer savings and provide benefits to all utility customers. SEIA and Vote Solar, together with numerous associations, environmental groups and clean energy advocates, has established net metering and rate design principles which guide SEIA's view on the creation of locational values.[10] SEIA is committed to developing accurate locational values that reflect the needs of the distribution system, identifying potential new revenue opportunities for DER projects from solicitations or new tariffs and programs, and working constructively in states that are considering modifications to net metering to incorporate locational value.

Based on our experience in these two jurisdictions, and building on our rate design and NEM principles, SEIA developed the following four principles for consideration with respect to the development and use of locational value for compensation.

1. Include the "full stack" of values of when designing compensation

Locational values have multiple components. First, there is the value in offsetting planned or potential investments in the distribution and subtransmission grid with less expensive DER options. Second, when properly authorized and wired, DER can help utilities and customers respond to localized system outages by providing power during times of interrupted service. Third, reduced electricity consumption also produces localized environmental and public health benefits and these benefits can be calculated and incorporated. Finally, there are values that DERs can provide for maintaining power quality, reducing line losses, and providing data to the utility for situational awareness.

Each of these locational values should be considered and rigorously analyzed when evaluating or developing compensation tariffs to capture the entire range of benefits that these resources provide. These values are additional to benefits that are system-wide (i.e., accrue evenly across the utility system), such as reduced need for powerplants, reduced greenhouse gases, and reduced high-voltage transmission. Both locational and system wide values should be considered together when using these values to evaluate DER programs or tariffs.

2. Ensure that locational values are long-term, stable, and financeable

As is done with utility investments, the locational value of DER should be structured to provide a consistent revenue stream over the life of the asset to ensure ease of financing. Utilities enjoy a regulatory structure that offers a return on- and return of- capital needed to make long-term investments. This proven mechanism has enabled utilities to confidently finance billions of dollars of assets and countless infrastructure improvements to meet the electric needs of society. Financial markets look kindly on this structure, which ultimately results in a lower cost of capital for the incumbent utility and lower costs for its customers. Distributed energy resource providers do not have such regulatory guarantees on their rate of return, but they should be afforded similar long-term financing treatment for the resources they deploy in lieu of utility-owned distribution equipment.

[10] Solar Energy Industries Association, Vote Solar, et al, "Principles for the Evolution of Net Energy Metering and Rate Design" (May 2017). Available at: https://www.seia.org/initiatives/principles-evolution-net-energy-metering-and-rate-design

Compensation tariffs to support DER investments must be structured to provide long-term revenue certainty to non-utility assets that are meeting utility customers' needs. If this fails to happen, and compensation tariffs instead rely on short- or medium-term time horizons that don't match the life of DER assets, the resulting tariffs will shortchange the value of the asset and make it difficult to arrange financing. When moving toward a more granular valuation of DER, regulators must ensure that the long-term value of the resource is recognized and properly included in compensation.

3. Ensure the reliability benefits of DER have value

Recent natural disasters have demonstrated the ability of solar coupled with battery storage to provide electricity service to individual buildings or groups of buildings.[11] In California, however, the value of DERs to provide reliability has, to date, been viewed narrowly. In piloting solicitations of DERs to meet distribution needs, California has defined reliability as the ability to provide "back-tie" capability. Specifically, DERs can reduce load, effectively increasing the amount of incremental load that could be transferred through a tie line should another line face an outage. For resiliency, the utility's LNBA demonstration projects considered the value of a micro-grid providing excess reserves for restoring customers and providing power within the microgrid during outages.

Looking forward, we expect that customer investments in stationary battery storage and other distributed energy resources (e.g., fuel cells) that can provide islanding capabilities from the grid and provide electricity service during outages will increase. This value should be incorporated into valuation and compensation frameworks moving forward.

4. Create opportunities for distributed grid services

Solar projects avoid generation, transmission, and distribution capacity projects that would otherwise have been needed.[12] While locational valuation creates an opportunity to better understand this value to the distribution grid, there are new capabilities that DER can provide unrelated to avoiding capacity-driven projects such as substation upgrades needed to meet growing loads. Specifically, DER could help provide new grid services including situational awareness and voltage and power quality management.

Providing Utilities with More Data to Improve Distribution Grid Operations

Using smart inverters and other devices located at customer premises, third-party DER providers could provide data services for utilities that would otherwise install sensing and communications equipment. By leveraging existing DER assets, the utility will not need to invest in duplicative hardware. The data from these systems helps inform the utility about the operations of its distribution grid, an ability known as "situational awareness."

Two important operational metrics are line voltage and line status (e.g. operating or experiencing an outage). In providing voltage and outage information, DER can provide functions similar to Advanced Metering Infrastructure, line sensors/fault detectors, and communication with line equipment, though DER can only provide the monitoring function and not the control function.

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[11] Some recent news stories have demonstrated the value of DERs in providing reliability during natural disasters. See for example: 1) examples of homes continuing to operate following this summer's hurricanes using solar and batteries: https://www.forbes.com/sites/peter-detwiler/2017/09/17/after-irma-solar-plus-storage-a-small-beacon-of-light-in-a-sea-of-darkness/#3a3aaaed340f; 2) a microgrid with solar and storage operating through California's wine country fires in October 2017: https://microgridknowledge.com/islanded-microgrid-fires/

[12] For example, see Robert Walton, "Straight Outta BQDM: Consolidated Edison Looks to Expand its Non Wires Approach" Utility Dive (July 19, 2017), https://www.utilitydive.com/news/straight-outta-bqdm-consolidated-edison-looks-to-expand-its-non-wires-appr/447433/

In addition to voltage, frequency, and the occurrence of an outage, DER can also provide loading information at each site to determine how much generation is being produced and used on site. By capturing and utilizing this information, utilities can use DER to help drive more effective smart grid programs, increase reliability, and increase grid utilization. Intelligence at the end of the line can be used to more efficiently operate the system. Power quality problems can be identified and resolved sooner, outages can be detected faster, modeling accuracy can be improved, and distribution state estimation could be implemented.

Improving Power Quality and Reducing Electricity Losses Through Voltage Management

As part of their core responsibilities, utilities must supply electricity to customers within established power quality standards. Because utilities do not always have visibility to the voltage on each line segment, they often raise line voltages at the substation to the upper end of the operating range to ensure customers at the end of the line are within acceptable standards. While this brute-force method keeps voltage within the required operating limits throughout the feeder, it also wastes electricity.

To address this waste from excess voltage, utilities are increasingly deploying conservation voltage reduction (CVR) programs. CVR is a demand reduction and energy efficiency technique that flattens voltage across a distribution circuit and allows the voltages to be lowered across the whole circuit. The impacts are significant: a 1% reduction in distribution service voltage can drive a 0.4% to 1% reduction in energy consumption.[13] CVR programs typically save 0.5% to 4% of energy consumption on individual circuits, and are often implemented on a large portion of a utility's distribution grid.[14] Because distributed PV with smart inverters can increase or decrease the voltage at any individual customer location, these resources can be used to more granularly control customer voltages.

CONCLUSION

The modern grid must more effectively use DER such as solar to meet system needs. Increasingly, states leading the way in grid modernization are determining locational values and considering compensation mechanisms to guide DER to areas where they can have the most impact. Although these compensation mechanisms can take multiple forms, when designing any such mechanisms, regulators must incorporate the full range of values that DER brings to the system. Offsetting traditional capital investment, reducing demand in specific locations, and providing consistent power during periods of interruption are all values that should be captured when designing compensation methods for DER; these values are in addition to system-wide values such as the ability to avoid new power plants and high voltage transmission. Furthermore, regulators should design compensation based on a long-term time horizon, with an eye toward establishing stable DER revenue streams. By developing appropriate compensation mechanisms that will enable DERs to flourish, regulators, utilities, and customers can transform the electric grid into one that will better meet the needs of all customers.

[13] Wang and Wang, "Review on Implementation and Assessment of Conservation Voltage Reduction", IEEE Transactions on Power Systems (May 2014).

[14] SolarCity, "Energy Efficiency Enabled by Distributed Solar PV via Conservation Voltage Reduction: A methodology to calculate the benefits of distributed PV with smart inverters in providing conservation voltage reduction" (June 2016). Available at: http://www.solarcity.com/sites/default/files/SolarCity-CVR_Benefits_Methodology-2016-06-28_v2.pdf

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Stakeholder Comments received after June 28, 2018 workshop

Please note: Ameren Illinois is providing this information as part of a Commission Staff-initiated workshop. Given that these discussions pertain to past litigation and may ultimately culminate in additional contested cases in the future, Ameren Illinois considers this information to be distributed in the context of a confidential settlement discussion, subject to Illinois Rule of Evidence 408.

Ameren Illinois appreciates this opportunity to provide comments related to the Illinois Commerce Commission's June 28 Distributed Generation Valuation and Compensation workshop and the associated Distributed Generation Valuation and Compensation white paper, version 2. Developing an accurate, fair, and manageable distributed generation valuation methodology is important to ensure a) customers have appropriate information to base economic decisions, b) utilities can efficiently and effectively manage the distribution system, and c) the State can meet its energy goals.

As outlined in the initial comments provided on March 29, Ameren Illinois reiterates its belief that the determination of the value of distributed generation to the distribution system may be guided by a few key concepts.

1. While the term distributed generation will be used throughout these comments to be consistent with the Future Energy Jobs Act (FEJA), a more widely used term that may better encompass the full breadth of technologies and applications that may be connected to the distribution grid is distributed energy resource or DER. Ameren Illinois considers a broad definition of DER in which DER is defined to broadly encompass any generation, storage, or other load managing resource connected to the distribution grid.
2. Notwithstanding, FEJA calls for an assessment of the value of distributed generation or DG to the distribution system. While distributed generation may provide value in other channels (i.e., generation, transmission, ancillary services), and to various parties (i.e. customer, society), the focus contemplated by FEJA is its value to the distribution system.
3. When considering the value of distributed generation to the distribution system, the valuation should take into account:
    a. The specific location on the distribution system, possibly down to the distribution line transformer.
    b. The times of day, week, or year it is available, and during what types of weather.
    c. The capabilities the distributed generation can provide (real power, reactive power, or both).
    d. Other distributed generation operating characteristics (ramp rates, voltage support, dispatch ability, etc.)

Several questions have been posed to help further frame the Illinois context and advance the discussion on how to comply with distributed generation valuation contemplated by FEJA. Ameren Illinois' responses to the specific questions are provided below.

1. Please provide any suggested revisions to the June White Paper.

Ameren Illinois has only one suggested revision to the June White Paper. Ameren Illinois does not agree that AIC's initial proposed distributed generation valuation approach is similar to Minnesota's. AIC's approach differs in many ways, including the following:

1. Minnesota's approach addresses the value of solar (VOS) to the grid and does not address other DER types. AIC intends to build a framework that addresses different types of DER.
2. Minnesota's approach is not location/geographic specific. Minnesota's approach is a tariff structure that is evaluated at a system wide level applicable to every location on the electric distribution network. AIC believes the PUA (Section 16-107.6(e)) contemplates a framework that evaluates the value of DG to the distribution system at the smallest practical distribution system asset level.
3. Minnesota's approach considered value blocks outside the distribution system, such as: Generation Capacity, Energy, Environmental and Distribution Capacity. The PUA properly appears to focus on the value of DG to the distribution system only.
4. Minnesota's approach does not consider the value of Volt/Var support to the distribution system. AIC's approach considers the value of DER in providing Volt/Var support to the distribution system.

2. What general approaches, whether they were included in the June White Paper or not, should be considered for use in Illinois?

In addition to the key concepts outlined above, Ameren Illinois offers the following framework which builds on the Company's previous comments:

The process should generally include:

1. System capacity studies starting at the smallest distribution system asset level (distribution line transformer) then aggregate results upstream towards the bulk supply sub-transmission power transformer. These studies could compare baseline system capacity (current state of the distribution system) against cases of distributed generation penetration at specific locations on the distribution system. These studies will use hourly historical load data, hourly load forecast data, DER generation profiles and current AIC planning and reliability criteria to asses system capacity needs at each distribution transformer node for a given distribution feeder. Costs of system upgrades for the current distribution system snap shot will be compared with costs of system upgrades with DER connected at a given location on the distribution system.

2. System line loss study comparing baseline (current state of the distribution system) against cases with distributed generation penetration at specific locations of the distribution system. System reliability studies including voltage, protection and phase balance comparing baseline (current state of the

distribution system) against cases with distributed generation penetration at specific locations of the distribution system. These studies will use hourly historical load data, hourly load forecast data, DER generation profiles and current AIC planning and reliability criteria to asses system capacity needs at each distribution transformer node for a given distribution feeder. Costs of system upgrades for the current distribution system snap shot will be compared with costs of system upgrades with DER connected at a given location on the distribution system.

3. Using the above results, an economic analysis could be used to determine the value of distributed generation at the specified location on the distribution system.

3. Regarding the different benefits of distributed energy resources, please provide input on the following:

a. Which value streams should be included in the Section 16-107.6 DG rebate?

See framework above. As outlined, there are only three types of value that should be considered:

1. Avoided distribution capacity costs
2. Reduction in distribution losses,
3. Value of voltage support that may be realized from distributed generation.

b. Which value streams should be separately compensated pursuant to Section 16-107.6?

Other value streams that could be considered as additional services for separate compensation under Section 16-107.6 could include operating reserves, and frequency regulation. Compensation for operating reserves and frequency regulation would flow from the applicable regional transmission organization's (RTO) available markets.

c. Which value streams are outside the scope of Section 16-107.6?

All non-grid related value streams such as, for example, societal value, carbon reduction value, etc.

d. How do value streams differ by project? For example, how do they differ for projects with smart inverters and those without?

The applicable value streams would not change by project, but the value calculation would change by project, depending on the type and characteristics of the DER and the inverter being used.

As to the specific issue of valuing and providing rebates to non-smart inverter installations, the application of any rebate should only apply to those non-smart inverter installations specifically referenced in the law, namely net metering customers who began taking service prior to June 1, 2017. It is in the best interest of all parties to limit the number of non-smart inverters on the grid. In fact, the Commission should consider requiring all new installations to use a smart inverter going forward, perhaps as an interconnection requirement.

e. How are any value streams reflected in current rate structures and how are they currently calculated?

As mentioned above, there are already rate structures in place or further proscribed by FEJA related to energy. Societal and carbon value of renewable generation is already captured in the Renewable Energy Credit framework already outlined in FEJA.

4. Regarding the calculations of the various value streams, if not included in your general response, please provide input on the following:

a. How should each value stream that is included in the Section 16-017.6 DG rebate be calculated?

See framework outlined in answer to #2 above.

b. What distribution system data, pricing data, forecasts, analysis results, formulas, or other information is necessary to compute the value of each value stream that should be included in the Section 16-107.6 DG rebate?

See framework outlined in answer to #2 above.

c. How should each value stream that is separately compensated pursuant to Section 16-107.6 be calculated?

As mentioned above, energy should be calculated in accordance with existing law or tariffs. Compensation for operating reserves and frequency regulation should be consistent with the rules and markets of the applicable RTO.

d. What distribution system data, pricing data, forecasts, analysis results, formulas, or other information is necessary to compute the

value of each value stream that should be separately compensated pursuant to Section 16-107.6?

Initially, no distribution system data is necessary for computing the value streams for separate compensation as outlined above. In the longer term, it may be appropriate to add a locational factor to the energy supply value based on the metered location on the distribution system. For this factor to be calculated, real time distribution system constraint / operating data would be needed.

e. **Should utility service areas be divided into distribution areas for the characterization of locational value and, if so, how?**

See framework outlined in answer to #2 above.

f. **Should circuits be graded into category levels for the purpose of establishing DG capacity value price points? If so, how should category levels be established?**

The framework outlines in #2 above if taken to the full extent would provide a unique value for every distribution transformer location on the system for each type of distributed generation type (solar, wind, etc.). With over 400,000 distribution transformers on the Ameren Illinois system, from a practical rebate communication and management standpoint, it may be beneficial to develop a more reasonable number of $ value categories (say 3-5 categories), that could be applied to each type of distributed generation for every distribution transformer location. The use of a circuit-level (or further upstream towards the bulk supply network) value may initially be practical and appropriate, although ultimately the benefits of geographic-, time- and performance-based value criteria will be better realized by the use of a distribution line transformer-level value.

g. **Should calculations be standardized across utilities, areas, or other characteristics?**

Yes, to the extent possible. The overall methodology should be standardized, but sufficiently flexible to take into account differences in data type / availability, system configurations, operating parameters, etc.

5. **For the distribution system data, pricing data, forecasts, analysis results, formulas, or other information that is necessary to compute the value of each value stream, please provide input on the following:**

   a. **Should there be standardization with respect to information used to compute values?**

Yes, to the extent possible. The overall methodology should be standardized, but sufficiently flexible to take into account differences data type / availability, system configurations, operating parameters, etc.

b. **Should there be standardization with respect to formulas used to compute values?**

Yes, to the extent possible. The overall methodology should be standardized, but sufficiently flexible to take into account differences data type / availability, system configurations, operating parameters, etc.

c. **Should there be transparency requirements with respect to information used to compute values?**

Ameren Illinois recognizes this process will incentivize customers to act as partners in the efficient development and utilization of the grid. Customers and DG developers will need sufficient price and location data to achieve the desired outcome. Ameren Illinois also recognizes the sensitivity of operating and customer data, and the proprietary nature of analysis systems that will be used. It is important to note that much of the data required for the calculation will be customer or operating sensitive and would not be prudent to release to the public. In addition, the software tools used to do the analysis are often specialized and proprietary. Considering these realities, a potential approach could be to make publically available only the methodology, the types of data that are inputs to the methodology, and the final locational computed values that are the outcome of the analysis.

d. **Should utilities be required to develop and share capital and investment plans and, if so, for what periods (for example, 5 year plans, 10 year plans, or some other period), and how often should such plans be updated?**

No more than is already required by existing regulation and practices.

e. **Should circuits be graded into category levels for the purpose of establishing DG capacity value price points? If so, how should category levels be established?**

See answer to 4f above.

f. **How often should compensation levels be calculated in order to ensure appropriate price signals are provided far enough in advance to meet anticipated need?**

As a starting point, rebate values could be calculated on a yearly basis. As the utilities are able to further refine and automate the calculation methodology, more frequent updates could be considered.

6. **Apart from value formulas and/or specific rebate values, should candidate deferral projects, deferred distribution investment, marginal cost studies, or other information be made public?**

   No more than is already required by existing regulation and practices.

7. **In terms of the next procedural steps prior to the initiation of the investigation pursuant to Section 16-107.6, we welcome your comments on the following:**

   a. **Should the Commission use a designated working group process? If so, how should the working groups be structured, governed, and otherwise implemented?**

      Ameren Illinois favors a collaborative and structured process that promotes consensus to the extent possible. Ameren Illinois would be open to any approach proposed by the Commission Staff or the Commission.

      i. **Are there areas or particular issues that more readily lend themselves to consensus resolution? If so, should these issues be separated from those issues where consensus may be more difficult to reach?**

         At this point in the process it is difficult to determine what the full breadth of issues may be, much less which would more readily lend themselves to consensus resolution.

      ii. **Are there any value streams that may take more time to develop that should be separated from value streams that may be more quickly developed?**

         The process should first focus on the value streams directly related to the rebate – namely avoided distribution capacity costs, reduction in distribution losses, and value of voltage support that may be realized from distributed generation. The remaining value streams that may be applicable to the Section 16-107.6 process will take much longer to determine as their value will be dependent on the applicable RTO, and there is no existing mechanism in place to measure and manage at the distribution level.

   b. **Should the Commission consider using a consultant to help with developing Section 16-107.6 compensation methodologies and values?**

Using an experienced, unbiased, and objective third party consultant to help facilitate the discussion and reach as much consensus as possible would be beneficial.

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Illinois Commerce Commission	)	
	)	
	)	
Distributed Generation Valuation and Compensation Stakeholder Workshop	)	
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COMMENTS OF COMMONWEALTH EDISON COMPANY

Commonwealth Edison Company ("ComEd") submits these comments in response to the solicitation of the Illinois Commerce Commission ("Commission") in conjunction with representatives of the Pacific Northwest National Laboratory ("PNNL") relating to the June 15, 2018 version of the PNNL whitepaper entitled "Illinois Distributed Generation Rebate Calculation Considerations"[1] ("Whitepaper") and the June 28, 2018, Distributed Generation Valuation and Compensation Stakeholder Workshop ("Workshop"). Representatives of ComEd attended that Workshop and will continue to participate in subsequent Workshops and other activities on this important topic.

I. Introduction

The Whitepaper outlines that it seeks to support the Commission "with initial stakeholder engagement to advance the conversation around distributed generation valuation in Illinois" while acknowledging that the Future Energy Jobs Act ("FEJA") requires the Commission to initiate a formal distributed generation valuation process.[2] ComEd recognizes that these Workshops are intended to engage interested stakeholders and help develop options for a

[1] AC Orell, *et al.*, Distributed Generation Rebate Calculation Considerations, https://www.icc.illinois.gov/downloads/public/DG/ILDGRebateCalcConsiderationsWhitePaper-061518-PNNL.pdf (Pacific Northwest National Laboratory, June 2018) ("Whitepaper").

[2] Whitepaper, at 1.

separate and comprehensive effort to discern and shape the future of distributed generation valuation in Illinois. Given that a formal, more comprehensive Commission process is required by FEJA, ComEd's comments focus on issues related to the applicability of distributed generation compensation and valuation methodologies implemented or discussed in other states to Illinois and only present potential issues requiring Commission analysis and resolution within a formal valuation proceeding consistent with Commission practice and procedure.

In previously submitted comments, ComEd expressed that any valuation formula approved by the Commission must be consistent with the statutory directive requiring that the valuation formula "reflect the value of the distributed generation to the distribution system at the location at which it is interconnected, taking into account the geographic, time-based, and performance-based benefits, as well as technological capabilities and present and future grid needs."[3] Within responses to the questions posed to stakeholders by Staff of the Commission and PNNL representatives, ComEd provided Illinois-specific context for the future consideration of distributed generation valuation and compensation by noting several distinguishing Illinois-specific factors such as electric industry restructuring, retail open access, the current use of embedded cost-of-service studies, and the reliance on two Regional Transmission Organizations ("RTOs"). Any distribution system-level compensation mechanisms should be based on objective cost-benefit analysis that can be applied efficiently and have the appropriate flexibility to adapt to unforeseen circumstances that can occur with new and rapidly advancing technology. ComEd suggested that distribution system-level distributed generation compensation mechanisms should reflect the spatial and temporal contributions to the distribution system and adhere to certain guiding principles, including:

[3] 220 ILCS 5/16-107.6(e).

- **Objective cost/benefit analysis is critical.** Regulatory policy and structural change should be guided by unbiased, objective cost/benefit analyses that correctly reflect costs to distribution system consumers and the distribution system as a whole. Decisions about how to value and compensate distributed generation should be grounded in such cost/benefit analyses. Objective and unbiased cost/benefit analyses generate information indispensable to parties, facilitating decisions that benefit society.

- **Dynamic Efficiency and Management Flexibility Are Essential.** The final model adopted must allow utility management the ability to adjust to changing circumstances; support and encourage innovation; allow timely implementation of technological advances; promote continuous efficiency improvement; and support long-term value for customers.[4]

Compensation mechanisms should be equitable, transparent, and efficient. Any methodology for distributed generation valuation and compensation should transparently send clear price signals to developers and customers and consider administrative efficiency. As Illinois' largest distribution utility and the builder, owner, planner, and operator of the distribution network covering northern Illinois, ComEd continues to recognize the critical role it is to play in discussions, workshops and the future Commission proceedings related to distributed generation. As it proceeds in supporting the integration of distributed generation technology into the distribution system, ComEd appreciates the opportunity to offer these Comments on the PNNL Whitepaper for Commission, Commission Staff, and other stakeholders' consideration in advance of the separate, comprehensive Commission effort to discern and shape the future of distributed generation valuation in Illinois.

II. The Future Energy Jobs Act ("FEJA") and Illinois Commerce Commission Process

FEJA requires electric utilities serving more than 200,000 customers in the State of Illinois to request Commission approval of a tariff to provide rebates valued at $250 per kilowatt

[4] ComEd Comments March 30 at 3.

of nameplate generating capacity, measured as nominal DC power output, to certain customers.[5] The aforementioned rebate value is fixed until the Commission approves subsequent tariffs or tariff revisions pursuant to the findings of an investigation into an annual process and formula for calculating the value of distributed generation to the distribution system at the location at which it is interconnected.[6] FEJA requires that the future distributed generation rebate valuation formula approved by the Commission "reflect the value of the distributed generation to the distribution system at the location at which it is interconnected, taking into account the geographic, time-based, and performance-based benefits, as well as technological capabilities and present and future grid needs."[7]

In its Whitepaper, PNNL states that with respect to FEJA "there are some different, reasonable interpretations because of the varying language used in the law."[8] Within the Workshop, PNNL listed resolution of this interpretation as a potential next step.[9] ComEd strongly disagrees. The language of FEJA is plain and moreover, based on representations from Commission Staff, it is ComEd's understanding that these Workshops are designed to advance the conversation around distributed generation valuation in Illinois and lay foundations for Commission, Commission Staff, and stakeholder understanding of technical, financial and policy implications. Because formal Commission analysis and resolution is required, the Whitepaper and these workshops are not the appropriate forum for assessing or resolving the "reasonableness" of any one interpretation of the statutory language, be it "broad" or "narrow." ComEd objects to any reference by PNNL in its Whitepaper, any future whitepaper, and/or final

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[5] 220 ILCS 5/16-107.6(b)-(c) and (f).
[6] 220 ILCS 5/16-107.5(e).
[7] 220 ILCS 5/16-107.6(e).
[8] Whitepaper at 2.
[9] Homer and Orrell, Illinois Distributed Generation Rebate Calculation Considerations, https://www.icc.illinois.gov/downloads/public/DG/ICC%20SH%20Workshop%20Jun%2028%20final.pptx (Pacific Northwest National Laboratory, June 28, 2018), at 29.

report to statutory interpretations related to the value of distributed generation under FEJA. The appropriate forum for such legal interpretations is the future Commission proceeding mandated by FEJA.

III. Select Whitepaper Issues

a. Data Transparency, Privacy, and Availability

In the Whitepaper, PNNL identifies data privacy, transparency, and accessibility as issues that need to be addressed in the valuation process, and in particular balancing the need for transparency, communication, and collaboration with protecting customers' privacy and the sensitivity of business data.[10] PNNL also proposes data types that likely will be needed to understand the locational and temporal value of distributed generation in Illinois.[11]

A number of proceedings at the Commission have addressed, and are addressing, customer data issues.[12] Illinois utilities recognize their obligations toward the stewardship of data and continue to enable the energy ecosystem of utilities, third-party vendors, customers, and others. ComEd, for example, has consistently been proactive in making data available to customers though Green Button Download My Data, retail suppliers through the supplier portal for access to AMI Historical Interval Usage, and third parties through Green Button Connect, each of which requires Commission authorization. Third-party vendors performing services on behalf of the utility to implement programs have access through secure data protocols. Also, ComEd offers anonymous data usage services where customer identifiers are not revealed.

As the penetration of DER and other new technologies increases, information sharing will continue to be balanced with security, privacy, and overall cost and efficiency. As the grid

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[10] Whitepaper at 5.
[11] Whitepaper at 19.
[12] *See generally*, ICC Docket Nos. 14-0701, 13-0073, and 13-0506.

is the foundational platform for the integration and eventual valuation of distributed generation, the unparalleled expertise of the utilities in operating and planning the grid, along with Illinois' regulatory oversight mechanisms, make them uniquely positioned and qualified to fairly and effectively manage that information sharing function.

In the Whitepaper, PNNL focuses on hosting capacity as a model for how other states have dealt with data privacy. While a fundamental understanding of the current infrastructure's capabilities assists stakeholders in making informed siting decisions, it does not provide the locational, temporal, and performance-based factors necessary for valuation of distributed generation. The PNNL Whitepaper identified a "wish list" of possible data sets that could be useful in establishing an approach to distributed generation valuation.[13] PNNL was not able to identify any one particular state that is utilizing the data sets set forth to determine the value of distributed generation. ComEd submits that it would be more useful to first establish the valuation framework through the Commission process established by FEJA, and then implementing it gradually, a process which may include pilot programs, test cases, peer review processes (that could include PNNL as well as other external industry experts), and other means to validate the approach. Once the components of distributed generation value (both positive and negative) are identified in the context of Illinois, a determination on what data is necessary to support the valuation calculations can be made. The methodology developed and calculations that support the locational, temporal and performance based factors necessary to determine the components of the valuation should be shared, so long security and privacy concerns are addressed. Data on own would not provide the locational, temporal and performance based factors necessary for valuation.

[13] Whitepaper at 19.

b. Stakeholder Engagement Process

With respect to a stakeholder engagement process to determine the valuation of distributed generation, PNNL cites comments provided after the March 1, 2018 workshop suggesting establishment of stakeholder working group(s) to determine the rebate valuation methodologies and calculations, similar to what other states have done.[14] PNNL suggests such a working group format could establish some common ground among stakeholders, and therefore minimize the number of contested issues brought before the ICC during formal proceedings.[15]

ComEd reiterates its comments in response to the first PNNL whitepaper, and again emphasizes that FEJA has already identified the process for determining the value of distributed generation in Illinois.[16] While a stakeholder process may potentially result in limited, high-level consensus around guiding principles for distributed generation valuation, any resulting valuation methodology must have the legal and regulatory imprimatur of the Commission, and any additional process suggestions or considerations are more properly reserved for subsequent, formal proceedings. However, there may be topics outside of the scope of the Commission's investigation of the value of distributed generation to the distribution system that would benefit from separate stakeholder engagement workshops.

c. Incremental Approach

There appears to be broad stakeholder consensus, or at least not much disagreement, that a gradual approach to the valuation process that keeps Illinois' particular market and policy goals in perspective throughout the process is appropriate in Illinois, consistent with the approaches taken in other states. ComEd concurs. Any timetable for implementation should be realistic and

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[14] Whitepaper at 7-8.
[15] Whitepaper at 7 (citing ELPC, *et al.*)
[16] ComEd Comments March 30 at 6.

reasoned, with time taken to incorporate lessons learned throughout the process and from the experiences gained in other jurisdictions that are moving along similar paths.

d. Valuation Components

PNNL presents a survey of the various value components used by other states in their calculations.[17] However those value components are often, if not always, based on state-specific policy goals or legislation.[18] In that respect, the Whitepaper fairly summarizes published reports and the efforts of various states to date. It is worth noting however that to date no state has established a locational value of distributed generation to the distribution grid at a location more granular than the distribution substation.

ComEd agrees that many of the values of distributed generation listed as "valuation components" and applied in particular states, as in the California Locational Net Benefit Analysis ("LNBA") tool example, potentially reflect value in varying degrees to distributed generation owners, consumers, society at large, and to the energy markets. These values may manifest themselves in energy cost savings, emissions reductions, or wholesale market price impacts. However, it is clear from the examples in the Whitepaper that the value of distributed generation *to the distribution system* have yet to be quantified.

In Illinois, the value of distributed generation to be measured and compensated in utility rates, as defined by FEJA, is the value of that distributed generation to the distribution system. ComEd acknowledges that there are examples, several of which are cited in the Whitepaper, where distributed generation may deliver additional value streams and societal benefits, and the

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[17] Whitepaper at 9-15.
[18] Whitepaper at 9.

value of distributed generation to the distribution system may only be a subset of the total value the installation and operation may bring.

Recognition of the distinction between the universe of values of distributed generation and the value specifically attributable to the distribution system avoids potentially "double counting" (*e.g.*, compensating the same value components in both the wholesale markets and in customer rates at the distribution level) the value components of distributed generation when determining valuation, or creating unfair cross-subsidies among customers. Valuing distribution system benefits is just one of several mechanisms that compensate distributed generation for the value that it provides, as other values may be compensated through renewable portfolio standards, wholesale energy and capacity markets, ancillary service markets, and tax and other incentives. For example, the Whitepaper dedicates some discussion to ancillary services value.[19] But just like the valuation of other distributed generation value components, there must be assurance that the ancillary services benefits that the distributed generation will provide are not compensated both in distribution rates and through markets or other existing or future mechanisms.

Given the various compensation mechanisms available to distributed generation, the determination of "the value of distributed generation to the distribution system" to set the rebate value cannot be done in isolation. It must be done from a more holistic perspective, considering all of the mechanisms that compensate distributed generation, to be sure that the overall compensation for distributed generation is sufficient yet not excessive, and to consider any appropriate policy changes to any of the compensation mechanisms. Again, in Illinois, FEJA only authorizes the Commission to approve a valuation methodology that compensates

[19] Whitepaper at 13-14.

distributed generation for value (including both benefits and costs) to the electric distribution system by wholly encompassing recoverability of costs within distribution system rates.[20]

IV. Conclusion

In addition to the Workshops and the PNNL Whitepapers, the Commission has posted on their website a number of suggested questions to be addressed in stakeholder comments. Many of those questions, to the extent they are within the scope of the Workshops, have already been addressed by ComEd in these and previous Comments to the PNNL Whitepapers; others are more appropriately dealt with in the context of the subsequent, formal Commission proceedings. ComEd appreciates the opportunity to offer comments on the PNNL Whitepaper and these workshops designed to advance the conversation around distributed generation valuation in Illinois and lay foundations for Commission and stakeholder understanding of technical, financial and policy implications, and looks forward to addressing many of the issues raised in the Whitepaper in formal Commission proceedings. However, ComEd holds firm that these Workshops are not the appropriate venue for legal interpretations related to the value of distributed generation under FEJA and opposes such references in the current Whitepaper and/or final PNNL work product.

Dated: July 27, 2018

Respectfully submitted,
COMMONWEALTH EDISON COMPANY

By: ______________________

[20] 220 ILCS 5/16-107.6(h)(2).

Round 2 Comments of the Environmental Law and Policy Center, the Environment Illinois Research and Policy Center, the Union of Concerned Scientists, and Vote Solar To the Illinois Commerce Commission Regarding the Distributed Generation Valuation and Compensation Workshop July 27, 2018

The above-listed organizations hereby submit their second round of comments to the Illinois Commerce Commission (ICC or Commission), the Department of Energy (DOE), and the Pacific Northwest National Laboratory (PNNL) regarding the Distributed Generation Valuation and Compensation workshop and white paper.[1] Our initial round of comments, dated March 30, 2018, emphasized that the development of full and fair values for distributed energy resource (DER) rebates will (1) take time and (2) require transparency and significant new data sharing.[2] These themes will be apparent throughout our second round of comments as well.

The ICC, DOE, and PNNL have requested stakeholder input following the release of a second draft whitepaper and a second workshop held on June 28, 2018. Below we list the ICC's suggested questions to be addressed in Round 2 comments and our responses.

Suggested questions to be addressed in Round 2 comments on DG rebate

1. **Please provide any suggested revisions to the June White Paper.**

2. **What general approaches, whether they were included in the June White Paper or not, should be considered for use in Illinois?**

[1] https://www.icc.illinois.gov/Electricity/workshops/DistributedGenerationValuation.aspx

[2] https://www.icc.illinois.gov/downloads/public/DGVCWorkshop/VoteSolar-ELPC-UCSEnv-IllinoisRPC.pdf

We recommend that the Illinois process start with a broad look at the full value provided by DERs. As stated in our first round of comments, over the long term, each of the individual values of DERs may be valued and compensated through different policy mechanisms, including the DG rebate established pursuant to Section 16-107.6. But it is important to ensure at the outset the ICC has access to information about all the benefits of DER to the electricity system so that the ICC can make decisions about what elements should be included in the rebate and what elements are compensated elsewhere.

With the deployment of the smart grid and advanced metering technology, we now have an increasingly sophisticated view of the benefits provided by distributed generation, including the positive hard dollar impacts of solar on grid operations. In addition, there are broad soft dollar benefits—such as economic development, financial risk management, and environmental benefits—that result from the deployment of solar energy. The picture that emerges is one of significant value that equals or exceeds average blended electricity charges.

While there may not be consensus on the scope of the values that should be addressed in the future DG rebate proceedings, this workshop and whitepaper process provides an opportunity to identify the broad set of grid benefits contemplated in the Future Energy Jobs Act:

> The State should encourage: the adoption and deployment of cost-effective distributed energy resource technologies and devices, such as photovoltaics, which can encourage private investment in renewable energy resources, stimulate economic growth, enhance the continued diversification of Illinois' energy resource mix, and protect the Illinois environment; investment in renewable energy resources, including, but not limited to, photovoltaic distributed generation, which should benefit all citizens of the State, including low-income households.[3]

[3] Public Act 099-0906, Section 1(a)(1)

Likewise, Section 16-107.6 contemplates services beyond those identified in the statute and requires the Commission to identify "any additional uses."

3. **Regarding the different benefits of distributed energy resources, please provide input on the following:**

   a. **Which value streams should be included in the Section 16-107.6 DG rebate?**

DG valuation is an evolving concept. We believe it is not yet clear which value streams need to be compensated in the DG rebate and which are compensated through other policy mechanisms. For instance, as stated in our first round of comments, there is "the potential for FERC to establish market participation rules for compensating additional values of DER through wholesale markets." Comments at 6. As a result, "[t]his may require the Commission to establish some interim values as placeholders for system benefits that cannot yet be quantified with precision or cannot yet be compensated through other market mechanisms". *Id*.

Among the different approaches to categorize benefit types, the categories used in the Minnesota Value of Solar proceeding capture the broadest scope of benefits realized by the utility, the energy market, the grid, or society as a whole:

- Fuel cost
- Plant O&M – fixed
- Plant O&M – variable
- Generation capacity
- Reserve capacity
- Transmission capacity
- Distribution capacity

- Environmental cost
- Economic development benefits/jobs

In addition to these categories of benefits, there are elements of solar technology that make it possible for solar resources to pro-actively contribute to infrastructure effectiveness, beyond the transaction values recognized above. Importantly, there are values that may be compensated through wholesale markets and the interactions between assets operating in different markets that should be considered.

b. Which value streams should be separately compensated pursuant to Section 16-107.6?

As discussed above, the answer to this question is for the ICC to determine, ideally through a policy of gradualism and interim steps, and depends on the status and evolution of other policy mechanisms.

c. Which value streams are outside the scope of Section 16-107.6?

The answer to this question depends on how the ICC interprets the statute and decisions it will need to make upon consideration in a docketed proceeding. Our view is that the law supports the Commission's initial *investigation* described in 220 ILCS 5/16-107.6(e)[4] being broadly based into all of the values of DG and that the Commission can then proceed to select which values should be compensated through the rebate and which are provided, or

[4] "The [Commission's] investigation [into an annual process and formula for calculating the value of rebates] shall include diverse sets of stakeholders, calculations for valuing distributed energy resource benefits to the grid based on best practices, and assessments of present and future technological capabilities of distributed energy resources." 220 ILCS 5/16-107.6(e)

should be provided, though other channels.[5] We urge the Illinois process leading up to the Commission's investigation under 220 ILCS 5/16-107.6 should start with a broad look at the full value of DERs and be informed through a stakeholder working group.

d. How do value streams differ by project? For example, how do they differ for projects with smart inverters and those without?

There are several variables that drive the different values for any given prospective project. Among those are the:

- type of project (this should broadly include different types of DERs including solar, storage, solar-plus-storage, small wind, combined heat and power, digesters etc.);
- location;
- size (i.e., is it part of a larger aggregation of projects that can be controlled collectively);
- equipment specifications (smart inverters vs. traditional, etc.); and
- operation plans (if it is a storage asset, will it be used to participate in ancillary services markets or wholesale capacity markets).

Smart inverters can have settings established or may be remotely controlled by the utility and thus may provide additional value to the system than projects without smart inverters.[6] Also, projects located in certain areas could have distribution level benefits while others might trigger the need for a distribution level investment.

[5] "The value of [DER] rebates shall reflect the value of the distributed generation to the distribution system at the location at which it is interconnected, taking into account the geographic, time-based, and performance-based benefits, as well as technological capabilities and present and future grid needs." 220 ILCS 5/16-107.6(e).

[6] Compensation should be commensurate with the level of control by the utility.

e. How are any value streams reflected in current rate structures and how are they currently calculated?

The current rate structure for DERs is full retail rate net metering, which is intended to compensate many aspects of DERs, not necessarily precisely but in a general sense. For example, Environment America's report *Shining Rewards*, describes how full retail rate net metering fairly compensates DG owners for the power and other benefits and services they provide to the grid, even though those benefits are often worth *more* than the compensation DG owners receive through full retail rate net metering.[7]

There are also renewable energy credits (RECs) available through the Illinois Renewable Portfolio Standard (RPS) pursuant Sections 1-56(b) and 1-75(c) of the Illinois Power Agency Act to represent the environmental value of the renewable energy generated by DERs. The value of RECs under the Adjustable Block Program are administratively set to create markets and do not necessarily reflect the full range of environmental and economic benefits of DERs. For example, the Illinois Power Agency will adjust REC prices in the Adjustable Block Program over time to hit RPS targets. These price adjustments do not reflect any underlying change in the inherent environmental value of solar. Similarly, the REC values for utility-scale PV projects are derived through a competitive process and have nothing to do with the inherent environmental value of the underlying project.

4. Regarding the calculations of the various value streams, if not included in your general response, please provide input on the following:

a. How should each value stream that is included in the Section 16-017.6 DG rebate be calculated?

[7] https://environmentamerica.org/reports/ame/shining-rewards

b. **What distribution system data, pricing data, forecasts, analysis results, formulas, or other information is necessary to compute the value of each value stream that should be included in the Section 16-107.6 DG rebate?**

c. **How should each value stream that is separately compensated pursuant to Section 16-107.6 be calculated?**

d. **What distribution system data, pricing data, forecasts, analysis results, formulas, or other information is necessary to compute the value of each value stream that should be separately compensated pursuant to Section 16-107.6?**

e. **Should utility service areas be divided into distribution areas for the characterization of locational value and, if so, how?**

With respect to data, as discussed in our first round of comments, there are three types of data needs: (1) a regularly updated hosting capacity analysis; (2) DER growth projections; and (3) a grid needs assessment. We also urge movement toward granularity in characterizing locational value, such as dividing the utility service area into distribution areas, which could illustrate the areas that have the most locational value, such as those with high peak loads and with high degree of ability for DERS to defer or avoid distribution equipment costs.

f. **Should circuits be graded into category levels for the purpose of establishing DG capacity value price points? If so, how should category levels be established?**

Yes, grading circuits could be a useful way to convey the relative need and value of DERs. For instance, the categories could be established as they do in Hawaii according to the percentage available on the circuit with respect to the hosting capacity limit (Green means greater than X percent available; Orange means less than X percent available, and Red means less than X percent available).

g. **Should calculations be standardized across utilities, areas, or other characteristics?**

Yes, standardization would aid the public and project developers in seeking to understand where DERs may have the most value.

5. **For the distribution system data, pricing data, forecasts, analysis results, formulas, or other information that is necessary to compute the value of each value stream, please provide input on the following:**

   a. **Should there be standardization with respect to information used to compute values?**

   b. **Should there be standardization with respect to formulas used to compute values?**

   c. **Should there be transparency requirements with respect to information used to compute values?**

Yes, to the extent possible, for all-of-the above. Utilities should provide standardized and transparent information, especially with respect to projections of load growth and DG growth. These data should be shared and discussed in a stakeholder process.

As an example, Minnesota developed a standard VOS (value-of-solar) methodology[8] and requires the utility to file periodic updates to the inputs to that methodology. Thus, the inputs will vary by utility and by time, but the methodology should be consistent and transparent to the extent possible.

[8] http://mn.gov/commerce-stat/pdfs/vos-methodology.pdf

d. **Should utilities be required to develop and share capital and investment plans and, if so, for what periods (for example, 5 year plans, 10 year plans, or some other period), and how often should such plans be updated?**

Yes. This should be viewed as a significant priority for Illinois because more robust distribution system planning is needed to accurately quantify DER value over the long-term. We recommend incorporating aspects of an Integrated Distribution Planning (IDP) process as set forth in a recent GridLab white paper prepared for the Public Utilities Commission of Ohio's PowerForward proceeding.[9] Some of the new capabilities that need to be developed include:

- Advanced forecasting and system modeling. Enhanced forecasting to reflect the uncertainty of DER growth, more detailed system modeling of loads and DER impacts on the distribution system.
- Hosting capacity analysis. Determining how much additional DER each distribution circuit can accommodate without requiring upgrades.
- Disclosure of grid needs and locational value. Identification and publication of opportunities for DER to provide grid services as non-wires alternatives; identification and publication of locations on each circuit where DER deployment can provide grid benefits.
- New solution acquisition. Acquiring or sourcing DER from customers and third parties to provide grid services using pricing, programs or procurement. For example, using the peak demand reduction capability of smart thermostats in a targeted way to reduce circuit peak loads and avoid the need for circuit or substation upgrades.
- Meaningful stakeholder engagement. Establishing processes for open dialogue, transparent information sharing, collaboration, and consensus building among stakeholders.

e. **Should circuits be graded into category levels for the purpose of establishing DG capacity value price points? If so, how should category levels be established?**

Yes, please see response above.

[9] https://static1.squarespace.com/static/598e2b896b8f5bf3ae8669ed/t/5b15ae6470a6ad59dcb92048/1528147563737/IDP+Whitepaper_GridLab.pdf

f. **How often should compensation levels be calculated in order to ensure appropriate price signals are provided far enough in advance to meet anticipated need?**

We recommend every two years.

6. **Apart from value formulas and/or specific rebate values, should candidate deferral projects, deferred distribution investment, marginal cost studies, or other information be made public?**

Yes. Transparency is important part of an Integrated Distribution Planning (IDP) process described above. These data should be shared and discussed in stakeholder process.

7. **In terms of the next procedural steps prior to the initiation of the investigation pursuant to Section 16-107.6, we welcome your comments on the following:**

a. **Should the Commission use a designated working group process? If so, how should the working groups be structured, governed, and otherwise implemented?**

We recommend that Illinois initiate an independent DER working group to discuss the rebate formulation and other important DER policy issues. Illinois can use the existing Energy Efficiency Stakeholder Advisory Group (EE SAG)[10] as a model, which we discussed in our first round of comments: "Any interested party may participate in the SAG, and parties may contribute the services of technical experts to review data and refine how the cost-effectiveness of particular programs and efficiency measures are evaluated over time."

i. **Are there areas or particular issues that more readily lend themselves to consensus resolution? If so, should these issues be separated from those issues where consensus may be more difficult to reach?**

We believe this could be part of the agenda-setting process and function of the working group.

[10] http://www.ilsag.info/home.html

ii. **Are there any value streams that may take more time to develop that should be separated from value streams that may be more quickly developed?**

We believe this could be part of the agenda-setting process and function of the working group.

b. **Should the Commission consider using a consultant to help with developing Section 16-107.6 compensation methodologies and values?**

Yes. One suggestion is the firm Clean Power Research,[11] which assisted with DG valuation efforts in Minnesota and has extensive experience in this area.

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About Us:

The Environmental Law and Policy Center (ELPC) is a not-for-profit organization that works to promote environmentally sound energy policies in Illinois and throughout the Midwest. Environment Illinois Research & Policy Center is a non-profit organization dedicated to protecting air, water and open spaces in Illinois. The Union of Concerned Scientists (UCS) combines technical analysis and effective advocacy to create innovative, practical solutions for a healthy, safe, and sustainable future. UCS has more than 500,000 supporters nationwide, including over 20,000 in Illinois. Vote Solar is a non-profit organization working to foster economic opportunity, promote energy security and fight climate change by making solar a mainstream energy resource. Vote Solar has members across the nation with more than 500 residing in Illinois.

[11] https://www.cleanpower.com/

ENVIRONMENTAL DEFENSE FUND'S
RESPONSE TO ICC'S QUESTIONS FOLLOWING DG WORKSHOP 2

Environmental Defense Fund ("EDF"), provides the following comments in response to the Illinois Commerce Commission's ("ICC") request for comments following the ICC's Second Distributed Generation Valuation and Compensation Stakeholder Workshop of June 28, 2018. EDF is a national nonprofit organization whose mission is to preserve the natural systems on which all life depends. Guided by science and economics, EDF finds practical and lasting solutions to the most serious environmental problems. EDF has a strong interest in minimizing the electric industry's significant contribution to climate change and other environmental problems.

Illinois's electric grid is evolving. Advanced Metering Infrastructure enables, among many things, two-way communication between meters, devices, and the utility's distribution system. Through the Future Energy Jobs Act ("FEJA"), the General Assembly set ambitious targets for procurement of long-term, preferably in-state, distributed generation ("DG"), and described a number of incentives for development of distributed generation. As noted by the General Assembly, smart inverters allow this DG to not only serve customer/owners' load but also to communicate with and respond to signals from the grid to provide 1) support during distribution system reliability events, and 2) other services, such as dynamic reactive and real power support, voltage and frequency ride-though, and ramp rate controls. 220 ILCS 5/16-107.6(a).

FEJA requires a one-time rebate for installation of distributed generation beyond a 5% threshold of total peak demand supplied by each ComEd and Ameren. Up until that threshold, customers may elect net metering for both the delivery and supply portion of their bill. Beyond that threshold, customers installing new distributed generation may net meter only the supply portion of their bill, but may apply for a one-time rebate for installation of distributed generation.

The Commission must determine the value of those rebates. When the total generating capacity of the utilities' net metering customers is equal to 3%, the Commission must open an investigation into an annual process and formula for calculating the value of distributed energy resource rebates. Among the factors to be considered in calculating the value are the location at which the generation is interconnected, technological capabilities, and future grid needs.

In preparation for that investigation the ICC organized two workshops and commissioned a white paper from the Pacific Northwest National Laboratory ("PNNL"). EDF participated in both workshops and is an active participant in the current 16-107.6(a) proceedings for both ComEd and Ameren. EDF appreciates the opportunity to provide comments here. Following Workshop 2, the ICC requested stakeholder responses a number of questions. EDF responds below to some of these questions.[1] We have provided relevant expertise and considerations where possible at this preliminary phase of the statutorily-required investigation. It should be further understood that EDF's lack of comment on any issue should not be construed as agreement with the position in the white paper or with any other stakeholder. EDF expects to modify, refine, and further develop the below in the 107.6(e) proceeding.

3. **Regarding the different benefits of distributed energy resources, please provide input on the following:**
    a. **Which value streams should be included in the Section 16-107.6 DG rebate?**
    b. **Which value streams should be separately compensated pursuant to Section 16-107.6?**

EDF, jointly with Citizens Utility Board, and other stakeholders have provided extensive testimony in ICC Docket Nos. 18-0537 and 18-0753 which is relevant to these questions. EDF maintains that FEJA provides clear guidance for the utilities in implementing this rebate. Any use of a customer's distributed generation and smart inverter that is 1) outside of a distribution system

[1] EDF understands that issues with determining the 3% and 5% thresholds discussed at 220 ILCS 16-107.6(e) will not be addressed in this process.

reliability event, and 2) goes beyond the specific requirements outlined in the statute must be separately compensated. EDF/CUB submitted "checklist" for determining whether a service provided by a smart inverter must be separately compensated pursuant to Section 16-107.6:

I. <u>Qualifying Smart Inverter Capability</u>

To be listed as a required capability, the function of the Smart Inverter must meet ONE of the following criteria:

- The capability is included in the definition of "smart inverter" in 220 ILCS 5/16-107.6

  OR

- The capability is required in the IEEE 1547 – 2018 standard

II. <u>Default Rebate Operation and Control</u>

To be activated and used by Ameren before separate compensation is required, the function or Mode of Operation must meet ALL of the following criteria:

- Must be for the purpose of preserving reliability

  AND

- Must only function during distribution system reliability events / abnormal operating conditions

  AND

- Must not operate during normal operating conditions

  AND

- Must fall within allowable ranges under the IEEE 1547 -2018 standard for the DER penetration Category

III. <u>Operation Where Separate Compensation is Required</u>

If the function or Mode of Operation of the Smart Inverter is used outside of a distribution reliability event and/or functions during normal operating conditions, and if the Commission determines that the function or Mode of Operation would be beneficial (including, but not limited to, voltage and VAR support, regulation, and other grid

> services), separate compensation over and above the basic $250 per kilowatt of nameplate generating capacity is required.

FEJA limits utility operation and control of smart inverters to distribution system reliability events for the purpose of preserving reliability without additional compensation. This statutory restriction ensures that utilities cannot control and operate smart inverters to achieve other objectives, such as economic curtailment, that could harm distributed generation. The General Assembly recognized that a general goal of "preserving reliability" could be too broad, and manipulated by a utility to claim any control or operation of a smart inverter is justified under their self-selected role as the arbiter of what preserves reliability. The General Assembly therefore further restricted utility operation and control of the smart inverters to the condition of "during distribution system reliability events." 220 ILCS 5/16-107.6. The whitepaper references many potential values DG and smart inverters can provide to the system. EDF concurs, and emphasizes that all of these values must be separately compensated if used by the utilities.

When considering which value streams should be included in the "basic" rebate as opposed to which should be compensated separately, the Commission should also bear in mind the difference between the value of "being" versus the value of "doing." That is, the statute clearly defines the basic requirements of smart inverters, and by simply meeting those basic requirements, customers are eligible for the basic rebate (currently $250/kW). Use of those functions – with the exception of for reliability purposes during reliability events – and use of other functions ("doing") requires separate compensation.

4. **Regarding the calculations of the various value streams, if not included in your general response, please provide input on the following:**

   a. **How should each value stream that is included in the Section 16-017.6 DG rebate be calculated?**

FEJA notes a number of considerations that values should reflect, including geographic, time-based and performance-based benefits, as well as technological capabilities and present and future grid needs. 220 ILCS 5/16-107.6(e). This is a non-specific and non-exhaustive list, given the broad nature of each. For example, "future grid needs" may vary based upon the extent of potential increased electrification. As the ICC has acknowledged through recent policy sessions and in the NextGrid process, advances in technologies such as electric vehicles may lead to increased load. DG could be used to, among other things, offset EV charging loads and future infrastructure investments. Each statutorily-noted value consideration is likely to be similarly-evolving based on technological innovations, a changing grid profile, etc. Additionally, the values should take into consideration the value of assets over their life – 25 years or more, in some cases – as opposed to, for example, their one-year capacity replacement value (and their value in the future may be different than their current value, as there will be many changes to the grid in the coming 25 years). As noted in the whitepaper, there are a number of existing examples from other jurisdictions for calculating these values, but EDF stresses that Illinois is in a unique position and should develop methodologies that take into account Illinois's unique characteristics.

7. **In terms of the next procedural steps prior to the initiation of the investigation pursuant to Section 16-107.6, we welcome your comments on the following:**

b. Should the Commission use a designated working group process? If so, how should the working groups be structured, governed, and otherwise implemented?

EDF is not opposed to a working group process to the extent that it provides an opportunity for Commission and stakeholder education and for reaching consensus where possible in advance of the 107.6(e) proceeding. However, it should be understood that such a process would not preclude parties from participating in the docketed proceeding, and should not be a substitute for that proceeding.

Comments on Behalf of the Solar Energy Industries Association and Illinois Solar Energy Association

1. Introduction

The Solar Energy Industries Association ("SEIA"), Illinois Solar Energy Association ("ISEA"), and the Coalition for Community Solar Access ("CCSA") (collectively "Joint Solar Parties" or "JSP") appreciate the opportunity to provide input on the Illinois Commerce Commission's ("ICC") informal Distributed Generation Valuation proceeding.

Established in 1974, SEIA is the national trade association of the United States solar energy industry and is a broad-based voice of the solar industry in Illinois. Through advocacy and education, SEIA and its 1,000 member companies are building a strong solar industry to power America. There are 34 SEIA member companies in operation in Illinois working in all market segments – residential, commercial, community solar, and utility-scale – representing millions of dollars of in-state investment and a significant portion of Illinois' 4,000 solar jobs. SEIA member companies also provide solar panels and equipment, financing, and other services to a large portion of Illinois solar projects. Established in 1975 ISEA, which has approximately 600 business and individual members, educates and advocates for the advancement of solar development in Illinois. The CCSA is a national coalition of businesses and non-profits working to expand customer choice and access to solar for all American households and businesses through community solar.

The Joint Solar Parties have broad collective knowledge and experience through participation in Distributed Energy Resources ("DER") valuation proceedings around the country. We look forward to working with the ICC and other stakeholders to develop long-term solutions that adequately value the benefits that DERs bring to Illinois residents and the grid in general, and doing so in a way that enables a market to develop in Illinois that can deliver these benefits.

1.1 Organization of Comments

The JSP appreciate the ICC's efforts to facilitate the comment process by providing a detailed list of questions for party responses. The JSP have organized our responses in a somewhat different manner, but we have addressed many of these questions in our response.

As discussed in our prior comments and described in the revised version of the Pacific Northwest National Laboratory's White Paper ("Revised White Paper"), we continue to believe that an iterative, evolutionary approach for determining DER value is necessary due to two overarching themes:

1. The evolution of DER technologies and the ability of utilities to integrate DERs into grid operations and planning, including the evolution of data availability and understanding of how to value and compensate DERs; and
2. The development of DER markets and businesses and the need for continuity and gradual, predictable changes in compensation levels and structures to enable the industry to scale up and reduce costs, including the near-term need for market certainty in the face of impending net metering caps.

Consequently, our comments are broken down into four main sections describing:

1. Evaluations of the methodologies employed in Minnesota and New York, the two examples described in detail in the Revised White Paper. These evaluations provide context for our recommendations in Illinois.
2. A brief discussion of incentive structures and considerations in translating value determinations into a rebate.
3. Near-term solutions to DER valuation, for use in circumstances where incomplete information or time constraints prevent a full evaluation of one or more value streams.
4. Long-term solutions that rely on a vetted, data-driven valuation methodology. These long-term solutions should remain iterative in nature, subject to refinement over time to improve their accuracy and granularity.

By "near-term" we refer to activities during the next 1-2 years, which involve establishing both an interim method of determining long-term DER value, and the methodology employed to translate that value into a rebate. By "long-term" we refer to continual activity that may take place over the next 5-10 years to validate, refine, and evolve valuation mechanisms. It is plausible that activities we define in the long-term path could begin in the 1-2 year timeframe (e.g., work to establish a firm scope and priorities) but any preliminary work of this type should be balanced with the higher priority of developing a near-term solution that ensures market stability and addresses the demands placed on stakeholders.

1.2 Summary of Key Themes

As Illinois continues to develop an approach to DER valuation it faces questions related to *process* and *methodology*. By *process* we refer to both the efforts to define a workable methodology, such as reaching agreement on data sources, assumptions, and modeling methods, as well as the individual steps and timelines for achieving this goal. In order to ensure that the process leads to reasonable outcomes, it is necessary to resolve several threshold issues up front. Letting these questions linger will frustrate future efforts. We identify four threshold issues and our associated recommendations below.

Valuation Requires Near- and Long-Term Tracks

We cannot emphasize enough how critical market certainty is for DER providers, or any industry for that matter. The uncertainty created by net metering caps, triggering a significant reduction in compensation for exports to the grid, presents a significant planning problem for DER providers. For some residential customers, that reduction could be up to 50% for the distribution and transmission components alone, and higher if volumetric charges for generation capacity currently contained in basic service rates are also excluded from the export credit. As discussed in our initial comments, the long and uncertain timelines associated with developing granular valuation methods and assembling the necessary data must be considered when planning the valuation process. We recommend that the process employ a near-term track to establish placeholder values, while a long-term track focuses on developing a granular methodology and refining it. We discuss possible near- and long-term approaches in more detail later in our comments.

Valuation Must Be Complete and Transparent

As shown by discussions in other DER valuation proceedings, the value of DERs is composed of a long list of individual components at different levels of the system, from generation to transmission to capacity to distribution. Energy value will be captured in electricity providers' net metering programs pursuant to Section 16-107.5 of the Public Utilities Act—both before and after the 5% cap in Section 16-107.5(j) is hit. In terms of quantifying transmission, capacity, and distribution components, distribution level values have historically presented the greatest difficulty. Additional difficulties are present in Illinois because after the 5% cap is hit for an electricity provider pursuant to Section 16-107.5(j), capacity and generation value are excluded—despite the persistent value solar brings to all customers related to these costs.

Thus completeness has two aspects. First, methods for identifying the full suite of distribution values must be established. We address this full suite of values further in our comments on long-term approaches to DER valuation. Second, the exclusion of generally recognized values must be remedied. The simplest way to do so would be to incorporate any excluded values into the rebate calculation.

As discussed in our prior comments, it is critical that evaluation methods be transparent, both from the perspective of the models used and the underlying data. We urge the ICC to adopt a default policy that all models use be non-proprietary and fully accessible by all stakeholders, inclusive of the underlying data. Any confidentiality concerns should be addressed on a case-by-case basis, fully supported by legal justification under Illinois law (e.g., customer privacy), and any requests of this type should be accompanied by alternative proposals sufficient to ensure stakeholders have access to the information they need to meaningfully participate in the methodology development process.

Zero-Values Are Not Appropriate Placeholders

There is no rational basis for assuming that the magnitude of a given DER value stream is zero, either because of data insufficiencies or because the value is difficult to measure. Numerous DER value studies have identified non-zero values for various components, and while the magnitudes may differ for utilities in Illinois, they should be assumed to exist at some level. By contrast, a zero value is entirely arbitrary, more so, for instance, than the volumetric distribution rate, which is at least based on actual distribution costs.

Smart Inverter Values are Incremental

The Revised White Paper correctly identifies that references to the DER rebate as a "smart inverter rebate" are technically incorrect, since some potential rebate program participants will not have a smart inverter. Furthermore, Section 16-107.6(c)(1) specifies a default rebate level of $250/kW-DC for non-residential customers, which carries a condition that the utility is permitted to control the smart inverter during "distribution system reliability events." As the JSP observed in our initial comments and the Revised White Paper observes, the statutory definition of DER value as it pertains to the rebate is broader, including "benefits to the grid" and "the value of distribution generation to the distribution system." Collectively, these details dictate that smart inverter value, in the form of specific grid services and additional uses a smart inverter can provide, may be incremental to other DER values, including but not limited to distribution capacity deferral.

2. Review of Valuation Methodologies

The Revised White Paper summarizes the distribution value methodologies employed in New York and Minnesota as examples of potential approaches. While there are aspects of methods and processes used in both states that could be reasonable to replicate in Illinois, both suffer from several shortcomings, as discussed below.

2.1 New York[1]

The defining feature of New York's Value of DER ("VDER") framework thus far is that the New York Public Service Commission ("NYPSC") adopted a transition to VDER for demand rate DER customers and community solar facilities without first establishing many critical details of how DER value would be determined. While it is true that the order establishing the transition to VDER contained directives (e.g., the use of marginal cost data), many details were left unspecified, to be addressed in utility implementation plans. In turn, significant constraints were placed on the development and review of

[1] NYPSC. Docket No. 15-E-0751. Order dated March 9, 2017 ("NY VDER Order"). http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={5B69628E-2928-44A9-B83E-65CEA7326428}.

actual calculations and data sources to be used because, having established an immediate transition to VDER, it was necessary to adopt calculation methods in short order. The NYPSC acknowledged that the calculation methods required further refinement in approving VDER implementation plans, but left those refinements to be made in a second phase.[2]

New York: Features That Could Replicated

Dedicated Iterative Approach: New York adopted an initial DER distribution valuation methodology in 2017, while also clearly stating its intent to follow an iterative, evolutionary approach. New York continues to refine its methods through a working group process.

Use of Marginal Costs: Avoided distribution costs, referred to as demand reduction value ("DRV") on a system-wide basis and locational system relief value ("LSRV") for locally differentiated value both use values derived from marginal cost studies. Marginal costs, as represented by a Marginal Cost of Service Study ("MCOSS") are the proper measure of avoided capacity value, although we note there are several shortcomings on how the MCOSSs were conducted and used to establish VDER rates.

Attention to Gradualism and Market Impacts: While not part of the valuation mechanism per se, but critically important from a policy perspective, New York adopted measures to mitigate market disruption and smooth a transition to the VDER system. First, it delayed a transition to VDER for mass-market (i.e., non-demand rate customers) in the interest of gradualism.[3] Second, it established a "Market Transition Credit" ("MTC") for community solar facilities designed to smooth the transition from full retail rate crediting to the VDER system. The MTC mechanism is implemented under a declining capacity block system. The MTC reduces the effective decline in customer compensation by raising total compensation for subscribers to a given facility to a set percentage of the retail rate (e.g., 100% for Tranche 1, 95% for Tranche 2).[4]

New York: Shortcomings

Incomplete Value Assessment: The present Phase 1 methodology incorporates only avoided distribution capacity values. It does not value other distribution value streams that can be supplied by smart inverters, including voltage control and reactive power management, nor does it include reliability and resiliency services, enhanced grid visibility, reduced O&M, extended equipment lifetimes, the potential for reduced sizing of equipment replacements (another form of avoided capacity cost), or an avoided transmission capacity component.

Inadequacies in the Use of Marginal Costs: While we support the use of marginal costs in developing forward-looking values, the current system being used to develop VDER rates suffers from several shortcomings that limit its assessment of true long-term DER value, as follows:

- <u>Lack of Transparency and Consistency</u>: The different approaches used by utilities in New York for Phase 1 vary considerably. This variability extends from the MCOSSs on which the values are to some degree based to various utility-specific adjustments and assumptions in deriving avoided capacity costs from these studies (e.g., selecting only a subset of marginal costs, using different approaches to identify local value areas). The need to develop these values quickly due to the

[2] NYPSC. Docket No. 15-E-0751. Order dated September 14, 2017 (NY VDER Phase 1 Implementation Order). http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BA04D9EF3-9779-477E-9D98-43C7B060DAEB%7D
[3] NY VDER Order, p. 86
[4] Ibid, p. 129-130.

need to implement the new VDER system prevented a thorough review and evaluation of the differing methods.

- Short-Term Perspective: The marginal costs used to derive distribution value are effectively short-term costs rather than long-term costs that would be avoided over the lifetime of a DER, since they are reset every three years for the system-wide component. This places DERs at a disadvantage relative to traditional investments because in contrast to a DER investment, the costs and revenue from an equivalent utility investment are locked in for the lifetime of the equipment, not periodically reset.
- Unpredictability: Related to the short-term perspective, the three-year lock-in for DRV and 10-year lock-in for LSRV fail to provide the certainty needed to finance DERs, and as noted above, disadvantage DERs relative to the guaranteed revenue associated with utility investments that provide the same service. The energy component and capacity component are not fixed for any appreciable period of time, creating further uncertainty.

2.2 Minnesota[5]

Minnesota's law requiring the establishment of a value of solar ("VOS") methodology specified a roughly eight month timeline for the framework to be developed, from the enactment of the associated legislation in May 2013 to the January 31, 2014 deadline for a proposal to the Minnesota Public Utilities Commission ("MPUC").[6] While the ultimate result of this process was reasonably complete taken as a whole, the distribution value calculation could be considered the least complete component, lacking many potential distribution values and resolution of issues associated with calculating localized values.

Minnesota: Features That Could Be Replicated

Distribution Capacity Value Methodology: The methodological approach used in Minnesota is not a true marginal cost study, but it could serve as a substitute if long-term marginal cost values cannot be obtained. The calculation could be considered to reflect inferred marginal costs based on historic trends in distribution capital investments.

Long-Term Outlook For Distribution Value: The VOS methodology develops an annual set of values for a 25-year period. Some cost components, such as generation capacity and transmission rely on values that are fixed over time, but the distribution value calculation uses an escalation factor. While the designation of the escalation factor itself is utility-determined and not entirely transparent, on a conceptual level the escalation factor is appropriate and reasonable because annual update filings show a substantial escalation in distribution project costs over time (e.g., roughly doubling from 2007 to 2016).[7]

Predictability: The VOS rate is recalculated every year, but as applied to community solar projects the annually updated rates are "vintaged", such that the 25-year rate schedule adopted in any given year is fixed for projects enrolled in that year. This feature provides critical certainty for DER providers and reflects the fact that avoiding a long-lived traditional investment avoids the cost of that investment for the life of a DER asset. The framework also uses an averaging system that dilutes the variations in capital expenditures that may occur from year to year, smoothing changes over time.

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[5] MN Dept. of Commerce. Minnesota Value of Solar: Methodology. April 9, 2018. http://mn.gov/commerce-stat/pdfs/vos-methodology.pdf.

[6] MN Laws 2013, Chapter 85 (HF 729), Article 9, Section 10. https://www.revisor.mn.gov/laws/2013/0/Session+Law/Chapter/85/

[7] MPUC Docket No. M-13-867. Xcel 2018 Updated VOS Compliance Filing. (MN 2018 VOS Update) January 4, 2018. Table 14. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={A00DC360-0000-C313-8861-68B431B2E390}&documentTitle=20181-138644-01

Minnesota: Shortcomings

Incomplete Value Assessment: The distribution value assessment only includes deferrable distribution capacity investments. Thus far the methodology has not been refined to add voltage management, a component of smart inverter services which is necessary to define in Illinois, nor does it include a suite of other potential distribution values. Xcel's application of the methodology to identify local distribution values, which first took place in its 2018 annual update filing, produced objections and resulted in an MPUC decision to convene a further stakeholder process.[8]

Lack of Transparency: Though the methodology for calculating the value of solar rate is defined, the actual value of solar rate is updated annually in a utility compliance filing. Of central concern for the distribution value calculation is that it relies heavily on utility determinations of which distribution investment costs are capacity related, and the escalation of those costs over time. The methodology itself does not define the parameters for making these determinations and publicly available data shows only the results rather than how they were arrived at. These judgments have a powerful effect on the results. In some past years, more than 90% of distribution capital expenditures were excluded from the system-wide calculation as non-capacity related.[9] Consequently, while 25-year "vintaging" is a critical feature of the Minnesota approach, transparency is lacking over what the values in future updates might be. This is concerning both from a business perspective (i.e., how to portray value when communicating with future customers) and from a public policy perspective (i.e., are the determinations made internally by utilities appropriate?).

Lack of Consistent Refinement Efforts: Though the initial adoption of the methodology indicated an expectation that it would be refined over time, a specific forum or mechanism to do so was never established. While some refinements have taken place, and a dedicated local distribution value stakeholder effort was established in 2018, discussion of improvements has largely been limited to the short comment periods afforded to stakeholders on the annual utility updates. Thus there is no systematic effort to identify and incorporate new values or otherwise evolve the model.

3. Incentive Structure

Section 16-107.6 specifies that the DER rebate be just that, a rebate. The term "rebate" is generally accepted to refer to an up-front incentive of the type contemplated by the initial non-residential rebate of $250/kW-DC. The JSP believe that Section 16-107.6 is entirely unambiguous in this respect, thus the incentive must be an up-front payment consistent with ability of a DER to address "present and future grid needs" as understood at the time of the rebate. Since a DER would be capable of addressing future grid needs over the course of its useful life, the rebate value must reflect value over the useful life of a DER. The JSP recommend a 25-year useful life, even though the JSP are aware of assets under contract for substantially longer.

In addition to the need to comply with clear directives provided by Section 16-107.6, the JSP observe that an up-front rebate based on long-term value at the time of installation would avoid the uncertainty created by ongoing payments subject to periodic adjustments to value-based compensation, such as in New York. A rebate approach also reflects the nature of avoided capital investments as "fixed" once they are avoided.

[8] MPUC Docket No. M-13-867. Order dated March 26, 2018. https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={402D6362-0000-CF18-AA45-3716E1D7B6D9}&documentTitle=20183-141380-01
[9] MN 2018 VOS Update. Table 14.

Further discussions are necessary to define exactly how an up-front rebate should be calculated based on the long-term value stream regardless of how that long-term value is calculated.

4. Short-Term Solutions Track and Proposal

Illinois law does not set the type of time-constrained deadlines for developing a DER valuation methodology that were present in equivalent efforts in New York and Minnesota. At the same time, more uncertainty is present in Illinois as to when the methodology will be needed because the timing of the 3% threshold in Section 16-107.6(e)—including how the 3% is calculated—is subject to uncertainty and potential dispute, and deployment rates under the Adjustable Block Program are unknown. Clarity is also lacking on the process for developing the methodology and how long it might take given unknowns about data availability and prioritization in determining the methods suitable to estimate different value streams. As discussed in our prior comments, the experiences in developing DER valuation methods in other states indicate that the time necessary to develop even a first generation methodology could be measured in years rather than months.

For that reason, we recommend that Illinois consider an alternative near-term approach. First we believe Illinois can follow New York's model of recognizing and responding to the differences between mass market customers compared to community solar or demand rate customers. Illinois' near-term approach can infer DER value as a simple percentage of applicable system costs and incorporate a market transition mechanism similar to the MTC in New York. The goal of this path is to establish an interim valuation mechanism that could be used, if necessary, to bridge the gap between an effective net metering "cliff" and the establishment of a more robust valuation regime, but most importantly to ensure a smooth a transition to that new regime. While some complicating factors exist for creating such a mechanism, discussed further below, our recommended approach is simpler and features fewer unknowns than other options. It also has several precedents in other states facing similar obstacles to developing a value-based compensation regime.

4.1 Conceptual Model

At their core, existing rates for utility service are based on cost of service, though due to the nature of costing methods, an individual customer's rates may depart from that customer's "true" cost of service. The existence and magnitude of this departure is a matter of perspective because reasonable people can (and, in ICC dockets, frequently do) disagree on the most appropriate methods of cost allocation and rate design. That said, service rates are still an approximation of the actual costs to serve a given customer.[10]

For behind-the-meter residential customers in Commonwealth Edison ("ComEd") territory, the compensation rate for exports to the grid could decline by 40-50% upon the triggering of the net metering cap due to the elimination of distribution and transmission charges from the calculation of the customer credit. This decline would be larger if the generation capacity component of generation supply charges, which is currently a volumetric charge in basic energy service tariffs, is also excluded from the export credit.[11] For instance, ComEd's volumetric charges currently total roughly $0.105/kWh, of which transmission and distribution comprise roughly $0.048/kWh (45%).[12] Absent additional compensation for DER value, a customer with a 50:50 split between direct on-site use and exports would see a compensation reduction of 22.5% (i.e., 50% X 45%). The Revised White Paper shows agreement between the JSP and utilities that DERs have a non-zero distribution capacity deferral value. Therefore allowing

[10] In reality, all costing studies are only approximations however they are conducted.

[11] Export compensation rate changes would be lower for customers paying demand-based rates for any of these components.

[12] See ComEd rates statements here: https://www.comed.com/MyAccount/MyBillUsage/Pages/CurrentRatesTariffs.aspx

this value to descend to zero is inappropriate even if precise valuation cannot be completed. For instance, the most recent update of Xcel Energy's VOS rate in Minnesota produced a combined system-wide transmission and distribution value of $0.0264/kWh (25-year levelized value).[13] Likewise, as described in the Revised White Paper, New York has established distribution capacity deferral values based on marginal distribution costs.

The Revised White Paper does not discuss transmission value though it does include high-level information on how the Minnesota VOS methodology treats transmission value, which is based on tariffed transmission rates plus losses, adjusted for DER coincidence with peak transmission loading. Transmission capacity deferral, adjusted upward for losses, is a commonly included element in DER valuation studies. The initial version of the White Paper notes several additional state examples of this, including California and Oregon. Other recent examples include consultant reports commissioned by the Maryland Public Service Commission ("MDPSC")[14], and District of Columbia Office of the People's Council ("DCOPC").[15]

Furthermore, this value is not just theoretical. For instance, in connection with its 2015-2016 transmission planning process, the California Independent Systems Operator ("CAISO") credited rooftop solar along with energy efficiency with avoiding the need for nearly $200 million in transmission upgrades.[16] In approving the 2017-2018 transmission plan the CAISO canceled 18 transmission projects and revised 21 other projects, avoiding an estimated $2.6 billon in future costs. The changes were mainly due to changes in local area load forecasts, and strongly influenced by energy efficiency programs and increasing levels of distributed solar generation.[17] Likewise, the PJM incorporates DER solar forecasts into its Regional Transmission Expansion Plan ("RTEP") through its load forecasting process, using a 15-year analytical timeframe.[18] It is inescapable that DERs can, should, and do play a role in transmission planning by modifying load growth patterns, and consequently avoiding expenditures on transmission infrastructure that would otherwise be needed to serve local loads.

We recommend that an interim DER value be established using a percentage-based methodology, adjusted by a market transition mechanism based on the New York MTC. There are multiple ways that the interim DER value component could be calculated. One way would be to calculate the benefit as a percentage of the retail rate applicable to a given DER customer. Another way could be to calculate it based on the service level at which a DER is interconnected, such that a DER is assumed to avoid capacity at and upstream of the service level at which it is connected. The latter approach may be preferable because it would accommodate community solar facilities that have customers in multiple rate classes. Either way, the resultant value can then be modified by the MTC, and then translated into an upfront rebate using a series of assumptions (e.g., 25-year energy production, assumed rate escalation, etc.).

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[13] MN 2018 VOS Update. Figure ES-1.
[14] MDPSC. Draft Report: Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland. April 10, 2018. https://www.psc.state.md.us/wp-content/uploads/MD-Costs-and-Benefits-of-Solar-Draft-for-stakeholder-review.pdf
[15] DCOPC. Distributed Solar in the District of Columbia. Filed in Docket No. FC 1030. May 19, 2017. https://edocket.dcpsc.org/apis/pdf_files/2dfe239c-cf38-452a-9290-31231edc34c8.pdf
[16] Julia Piper. Greentech Media. "Californians Just Saved $192 Million Thanks to Efficiency and Rooftop Solar". May 31, 2016. https://www.greentechmedia.com/articles/read/Californians-Just-Saved-192-Million-Thanks-to-Efficiency-and-Rooftop-Solar#gs.NdkrQbo
[17] Corina Rivera Linares. Transmission Hub. "California ISO 2017-2018 transmission plan identifies 17 projects as needed to maintain reliability". March 15, 2018. https://www.transmissionhub.com/articles/2018/03/california-iso-2017-2018-transmission-plan-identifies-17-projects-as-needed-to-maintain-reliability.html
[18] PJM. 2017 Regional Transmission Expansion Plan. See Book 2: Inputs and Processes. http://www.pjm.com/library/reports-notices/rtep-documents.aspx

4.2 Practical Application of the Model

The setting of rebate amounts must consider the different needs and circumstances of residential, non-residential, and community solar DERs in the context of state policy goals and gradualism. As discussed in more detail later in our comments, interim mechanisms in other states are typified by effectively zero, or modest, changes to overall compensation experienced by DER customers while durable valuation mechanisms are being developed. We recommend New York as a general model for this purpose since it displays market segment differentiation in order to support continued growth in each segment. More specifically, the MTC mechanism is a reasonable way to balance a gradual transition to a value-based regime with increased maturity of individual market segments.

In practice, this could take the form of MTCs for each market segment that fill the difference between the needs of individual market segments and calculated DER values. As we describe further below, DER values not explicitly defined as "distribution" value and not reflected in other compensation require consideration as well. A well-designed MTC framework can be used to incorporate these components into an all-encompassing system. While we are describing this in the context of our near-term proposal, an MTC could endure in future iterations of the valuation system as a balance to the fact that even more granular valuation regimes will remain incomplete for some time.

The calculation could be made more elaborate by considering:

1. Varying the rebate by system orientation so that amounts vary for South-facing vs. West-facing systems based on likely peak contribution.
2. Coincidence with the range of peaks at different levels of the transmission and distribution system.
3. Methods of incentivizing participants to reduce or minimize exports.

As noted in the prior section, the translation of 25-year value to a rebate, regardless of how DER value is determined, requires further discussion.

4.3 "Triggers" Under the Model

As we have already described, uncertainty remains in the calculation of net metering penetration benchmarks, and the difference between pre- and post-cap compensation to customers is meaningfully different depending on customer segment. Residential and small commercial customers would experience the most significant changes. It is also uncertain what portion of those caps will be met by different customer segments. One reasonably foreseeable outcome is that the behind-the-meter residential and small commercial sectors, which experience the greatest negative impacts of an energy-only netting regime, end up comprising only a small portion of the overall NEM cap (e.g., 1% of the peak load calculation, equivalent to 20% of the 5% cap). At least 25% of the Adjustable Block program is directed toward 10 kW or less behind-the-meter systems, and such a shock could make meeting the statutory requirements for the Adjustable Block program substantially more difficult. Given the Illinois Power Agency's ("IPA") general approach to the Adjustable Block program—which currently assumes full retail net supply and delivery metering for customers with 10 kW behind-the-meter systems—a substantial reduction in net metering (or net metering replacement) revenues would cause a substantially similar cost increase for the REC contract.

The purpose of the MTC is to moderate changes in total compensation along a glide path to a value-based compensation regime, which in our conceptual model, is individualized by market segment. We propose, in order to avoid unexpected, sudden, and substantial changes that may endanger systems procured pursuant to the Adjustable Block program and consumer expectations, that the starting value of a segmented MTC is the amount necessary to bring total compensation to 100% of pre-5% cap net metering value. For the residential sector on non-time of use rates, for instance, such a value would be full retail supply and delivery (excluding energy), while for non-residential customers it would replace the $250/kW smart inverter rebate and the difference between 16-107.5(e) or (f) net metering and energy netting. The question then becomes what level of DER penetration within a given segment triggers a reduction in the MTC, so as to reduce total customer compensation below pre-5% trigger value. We propose that non-demand rate, behind-the-meter DER customers not experience such a reduction in total compensation until they achieve a designated percentage of net metering penetration for their specific rate class or the IPA's initial allocation of under 10 kW behind-the-meter systems have been successfully placed under contract**.** This would preserve equity and diversity in the opportunities afforded to different DER sectors.

4.4 Role of Customer Charges in Distribution Cost Recovery

It is the JSP's understanding that Illinois has historically used an embedded cost approach—allocating a percentage of distribution revenue to a class of customers and creating rates meant to recover those costs— rather than defining charges based on a delineation between customer-specific distribution costs and shared distribution costs. This practice bears relevance to the interim value method we describe above insofar as the current retail distribution rates are not designed to fully segregate the costs of shared distribution facilities from direct customer costs (e.g., service drops). This is another reason why an approach derived from costs at individual service levels rather than a rates-based approach could be preferable. In other words, distribution rates themselves do not reflect full distribution costs because a portion of shared distribution costs are recovered via customer charges.

To be clear, are not suggesting that the development of a DER valuation methodology address distribution cost allocation or retail rate design. However, it is an issue to consider in the context of our interim proposal because existing rate designs already modify (i.e., reduce) the connection between distribution rates that can be offset by DERs, and full, shared distribution system costs. This figures into what portion of a rebate is considered part of DER value, and what portion could be considered part of an MTC.

4.5 Inclusion of Other DER Value Streams

We have included transmission value in our interim valuation proposal and believe it should also be considered part of the rebate calculation in our long-term solution proposal described in a subsequent section for several reasons:

1. Section 16-107.6 specifies that the rebate investigation include "calculations for valuing distributed energy resource benefits to the grid". The transmission system is an integral part of "the grid".
    a. In fact, the Commission has held that transmission is part of distribution: "As explained by ComEd, the reference to 'electricity produced' plainly refers to the tangible quantity of electricity produced by the project – no mention is made of any services, whether transmission services or volumetric non-distribution services. **Indeed, Section 16-102 of the PUA classifies transmission as a delivery service** – not a supply service. 220 ILCS 5/16-102." (ICC Docket No. 17-0350, Final Order dated September 27, 2017 at 15 (emphasis added).)
    b. Even though transmission is assessed on the electricity supplier and not the distribution utility (unless the utility is also the supplier), the Commission's holding demonstrates that *at minimum* reducing transmission costs is a "benefit to the grid" if not "value of the distributed generation to the distribution system."
2. Section 16-107.6 also specifies that rebates "reflect the value of the distributed generation to the distribution system at the location at which it is interconnected." The transmission system is part of the system of wires used to distribute or deliver electricity and transmission costs vary by location due to both embedded costs and congestion. Furthermore, there is no bright-line test for determining whether a given line is classified as transmission or distribution. Utility

classifications based on voltage vary and some utilities define a further sub-class of delivery infrastructure as "sub-transmission".

3. It is undeniable that at a minimum, DERs reduce losses on the transmission system by providing physical supply locally that need not be provided via the transmission system. Interconnection regulations prevent individual DERs or aggregate groups of DERs from backfeeding power through a substation to the transmission system, meaning that no energy from DERs will ever reach the transmission system. Furthermore, DERs produce immediate, tangible operational benefits beyond even the deferral of transmission capacity expansion by reducing local transmission loading and congestion.

The inclusion of transmission in the DER valuation regime is supported by the spirit and intent of Section 16-107.6 with respect to properly assigning value to DERs, and is also consistent with the language despite the lack of an express reference.

Generation capacity is a further DER value stream that is not expressly referenced in Section 16-107.6 as components of the rebate. As stated in our initial comments, the JSP believe that the Legislature's intent was to establish mechanisms that provide compensation for the *full* set of DER value streams—especially as net metering required in Sections 16-107.5(d), (d-5), (e), (f), and (*l*) reverts to "energy netting" after the 5% cap from 16-107.5(j) is hit. Generation capacity, inclusive of capacity reserve margin, is consistently part of DER valuation efforts in other jurisdictions, including the New York and Minnesota examples described in the Revised White Paper. This inclusion is typically not controversial. To the extent that compensation for these values is not already accurately reflected in other forms of compensation, they should be included in the rebate calculation and consideration of the MTC.[19]

4.6 Alignment Illinois Law

Section 16-107.6 requires that the rebate reflect geographic, time-based, and performance-based benefits of DERs. The interim valuation determination that we recommend can be made consistent with all of these features:

Geographic: Geographic differentiation would be reflected by establishing separate rebate amounts for different utility service territories.

Time-Based: The time-based benefits of DERs could be reflected by considering system orientation and other factors that affect the solar generation profile and how it contributes towards serving peak loads

Performance-Based: System production estimates could be individualized for each rebate recipient through the use of a standardized estimation model. This approach has been used in the past for a number of programs in other states, typically referred to as an Expected Performance-Based Buydown ("EPBB") incentive model. Performance, in terms of incentivizing on-site consumption over grid exports, could also be reflected in different ways so as to encourage behavioral changes or incentivize storage.

4.7 State Precedents

Key Themes

Various states have pursued their own investigations of net metering in the last several years and ultimately failed to resolve the interconnected and complicated set of issues associated with adapting DER compensation methods to provide value-based signals. In most of these cases regulators had more

[19] We observe here that demand-based charges in general, whether for generation capacity, transmission, or distribution, do not fully value DERs because they do not accommodate the "negative demand" provided by exports. This negative demand has value equal to load reduction.

flexibility to devise "alternative" regimes than is present in Illinois insofar as they had the full discretion to choose any model they saw fit. By contrast, Illinois law currently specifies a firm end to net metering (beyond energy netting) rather than an alternative model, and requires value-based compensation to take the form of a rebate.[20] Despite these differences, the methods employed in other states point to a consistent strategy for addressing possible disconnects between DER compensation and DER value.

Several decisions of this type have adopted systems similar to the interim near-term model we propose, where either the monthly credit for exports or the credit for gross exports is reduced by a *small* amount to address concerns that the value of DER energy production is less than the volumetric retail rate, in some cases focused only on transmission and distribution. In several of these states, Arizona, New Hampshire, and Utah, regulators continue to pursue longer-term initiatives to further define DER value streams and reliable methods for calculating DER value.

We wish to emphasize here that we are not recommending any of the specific approaches described below. Instead we point to what they show as a collective whole, that when faced with significant unknowns, policymakers have chosen interim methods characterized by moderation, to wit, very modest (or no) reductions in compensation while further investigation takes place.

Thus while we describe a number of examples of state-level decisions exhibiting moderation in the following sub-section, we emphasize that even small changes can have long-lasting, disruptive impacts, the more so when they are unpredictable or sudden. **Because these decreases in valuation in states mentioned below are still new, we recommend the ICC complete an analysis of practical impacts these reductions are having on customer choice and investment.**

Examples

Arizona: Arizona's DER export tariff sets compensation for residential and small commercial customers for exports to the grid at a less than retail rate, based currently on a Resource Comparison Proxy ("RCP") that reflects the costs of historic utility-scale solar energy purchases. This rate is updated annually but may not decline by more than 10% each year and customers may lock-in the applicable annual rate for 10 years. This proxy method is to be used until a value-based export compensation methodology can be finally established.[21] While this model is indicative of some level of moderation, the annual reductions are arbitrary from the perspective of both DER value (i.e., DER value is not necessarily related to utility-scale PPA pricing) and timing (i.e., no consideration of market impacts).

Maine: Maine established a revised netting system with an annually declining percentage of "nettable energy" for the transmission and distribution portion of a customer's bill. Beginning in 2018 this percentage is 90% and then declines by 10% increments during the next 10 years. DER customers lock in the applicable annual percentage for 15 years.[22]

Nevada: Nevada adopted an alternative net metering regime for systems 25 kW or smaller through 2017 legislation. Like many incentive programs, new net metering system uses a capacity tranche (80 MW) system that progressively reduces the carryover rate for monthly excess generation from the full retail rate

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[20] The JSP understand that some electricity providers may hit the 5% cap in Section 16-107.5(j) before others, and electricity providers may hit that 5% cap before or after the 3% or 5% trigger in Section 16-107.6.
[21] Arizona Corporation Commission. Decision No. 75859. January 3, 2017. http://docket.images.azcc.gov/0000176114.pdf
[22] Maine Public Utilities Commission. Docket No. 2016-00222. Order dated March 1, 2017. https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/ViewDoc.aspx?DocRefId={993E4ACC-029B-4EA4-A38A-885DEC26E0CC}&DocExt=pdf

to 95% for the first tranche, 88% for the second tranche, 81% for the third tranche, and 75% for all new installations after the third tranche is filled.[23]

New Hampshire: New Hampshire's Alternative Net Metering regime reduces the rate at which distribution charges are credited on a monthly basis to 25% of the volumetric distribution rate. In other words, rather than a kWh credit that effectively includes all volumetric delivery charges (i.e., distribution at 100%), the customer receives a monetary credit composed of the sum of 25% of the distribution rate and 100% of other volumetric rate components. Stakeholder work on devising the parameters for a DER value study is ongoing.[24]

New York: As we have previously described, New York's transition to the VDER model retained traditional net metering with compensation for exports at the full retail rate for mass-market customers (i.e., non-demand) customers. In doing so the associated order recognized that "[m]aturation of this market segment and appropriate business models will require notice and a more gradual evolution to a new compensation methodology."[25] Furthermore, New York established the MTC for community solar facilities to smooth the transition from full retail rate crediting to the VDER system, implemented using a declining capacity block system. The MTC reduces the effective decline in customer compensation by raising total compensation for subscribers to a given facility to a set percentage of the retail rate (e.g., 100% for Tranche 1, 95% for Tranche 2).[26]

Utah: Utah's net metering transition program reduces compensation for all exports to the grid (as measured in 15-minute intervals) to 90% of the average energy rate for residential customers and 92.5% of the average energy rate for non-residential customers. The program is capped at 170 MW for residential systems and 70 MW for all other systems. A new proceeding will be convened in the future to establish a durable export credit rate.[27]

4.8 Smart Inverter Compensation

The interim calculation method described above is not intended to be inclusive of grid services and additional uses that smart inverters provide. Smart inverter functions, such as the Volt-Watt, Frequency-Watt, and Volt-VAR with reactive power priority functions provide incremental system value beyond values such as distribution capacity deferral and avoided distribution losses that DERs not equipped with smart inverters can provide. The activation of these smart inverter functions represents a tradeoff for a DER customer, a reduction in the ability to produce real power for the customer's own use in exchange for compensation for the value that foregone real power production has to the grid. In other words, a DER customer is forgoing their exclusive right to benefits of the system to allow it to be operated for the benefit of all customers. This type of shared usage is incremental and must be compensated beyond the rebate compensating eligible customers whose DERs are not equipped with smart inverters.

The JSP provided a fuller discussion of the grid services and additional uses that smart inverters provide in testimony submitted in Docket Nos. 18-0537 and 18-0753 relating to ComEd's and Ameren's interim DER rebate applications. Please see the footnoted links below to view the testimony from the Ameren

[23] Assembly Bill 405 (2017). Enacted June 15, 2017. https://www.leg.state.nv.us/Session/79th2017/Bills/AB/AB405_EN.pdf

[24] New Hampshire Public Utilities Commission. Order No. 26,029. June 23, 2017. http://www.puc.state.nh.us/Regulatory/Docketbk/2016/16-576/ORDERS/16-576_2017-06-23_ORDER_26029.PDF

[25] NY VDER Order. p. 86.

[26] Ibid. p. 129-130.

[27] Utah Public Service Commission. Docket No. 14-035-114. Order dated September 29, 2017. https://pscdocs.utah.gov/electric/14docs/14035114/29703614035114oass9-29-2017.pdf

proceeding, which provides a more complete picture of the nuances associated with smart inverter grid services, additional uses, and compensation.[28]

5. Long-Term Solutions Track and Proposal

The JSP expect that developing a robust DER valuation methodology will take at least several years based on experiences in other jurisdictions. We anticipate that devising even a reasonably complete first generation model could take in excess of two years given the need to collect multiple years of data to validate models, DER performance, etc. In practice, efforts to develop and refine methodologies could span years beyond that. For instance, New York's Value Stack Working Group was formed in June 2017 for developing improvements to the VDER model. This group already possessed marginal cost studies and methods that were subject to at least some prior review and comment, but has yet to fully develop even an initial set of refinements.[29] As described in our initial comments, this effort would be best accomplished through a working group process with mandates and defined deliverables. In the following subsections we re-iterate several characteristics that should govern this process and elaborate on core distribution value components, prioritization of certain aspects, and related matters.

5.1 Importance of Process and Transparency

A stakeholder driven methodology development process will not function well or produce good results without a clearly defined mission and transparency-oriented attitude. We discussed how this process could operate at some length in our initial comments and will not repeat all of those recommendations here. However, we do wish to re-emphasize the need for two key features:

1. Quasi-informal, outside of a potentially constraining regulatory process, but with a clear core set of objectives and defined deliverables.
2. An emphasis on full transparency of any models developed for use in determining values and the accompanying data.

The need for transparency cannot be emphasized enough. Despite the years long stakeholder process to develop locational value models and tools, integrate DERs into distribution planning, and devise methods for securing DERs to defer distribution upgrades in California, progress has recently been frustrated by efforts to hold significant and impactful information confidential and potentially exclude some stakeholders (i.e., DER providers) from critical steps in in the distribution planning review process. Illinois would benefit from tackling this issue at the outset of stakeholder proceedings, and the JSP recommend that the "default" policy should be full transparency and participation absent a legal justification for confidentiality or exclusion.

5.2 Core Value Components, Data Needs, and Priorities

At a high-level, the JSP believe that valuation efforts should be prioritized based on a combination of likely magnitude of different value streams, ease of development, and Illinois' statutory requirements. Collectively we identify the following first priority items that demand prompt attention.

Determine Market Segment Differentiation: Our near-term proposal would establish differential treatment by market segment and contemplates that an MTC mechanism could continue to exist in later phases of

[28] ICC. Docket No. 18-0537. Direct Testimony of the JSP Parts 1 and 2.
https://www.icc.illinois.gov/docket/files.aspx?no=18-0537&docId=273252 (Part 1).
https://www.icc.illinois.gov/docket/files.aspx?no=18-0537&docId=273255 (Part 2).

[29] See NYPSC Matter No. 17-01276 to view the history and proceedings of the Value Stack Working Group.
http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?Mattercaseno=17-01276

the transition to a value-based regime. It will be establish when and how different customer segments transition to more granular value-based regimes at the outset of the long-term process so that transition mechanisms can be known in advance and DER providers can adapt to them. For instance, the transition path will almost certainly influence how DER providers plan for offering energy storage in concert with generation DERs, depending on how the attributes of energy storage are reflected in the valuation regime (see below).

Develop and Vet Marginal Cost Studies or a Substitute: Marginal costs are the proper measure of avoidable costs. Since Illinois' utilities do not conduct marginal cost studies currently as part of formula rate updates or revenue-neutral allocation proceedings, it could be challenging to develop a marginal cost valuation model in the near term. If it turns out not to be possible to do so in a reasonable time frame, efforts should focus on:

1. Working to establish the parameters for future marginal cost studies and how they will be used to develop DER values.
2. Devising a substitute method and the parameters surrounding its use. The Minnesota VOS method could serve for this purpose, but we emphasize that Illinois should go beyond what Minnesota has done to introduce further standards defining how cost escalation is done and how costs are classified as deferrable or not deferrable. Further discussion should also include the historic timeframe used to establish first year capacity costs, as well as a more general and detailed review of the overall methodology.

Focus on System Level: The initial focus should be on establishing methods for determining value at the system level and validating the approach. This would satisfy the statutory requirement for geographic differentiation without over-complicating the effort (i.e., crawl before walking).

Focus on Distribution and Transmission Capacity Deferral Value: Developing these values has precedent in other jurisdictions and both are likely to be significant value streams based on results in other value studies. While the finer details of the methods need to be reviewed, as noted above the Minnesota VOS methodology could serve as a starting point. This effort should include the definition of line loss values that become incorporated into capacity deferral values, adjusted from any average line loss factors to reflect higher marginal line losses during peak periods.

Establish Smart Inverter Valuation Mechanisms: Because smart inverter operation is a key component of the DER rebate program and participation will require activation of smart inverter features for many customers, making progress on this valuation aspect is important. We anticipate that this could be challenging because smart inverters are themselves relatively new technology and equipment and operational standards have not yet been fully defined.

Determine How Energy Storage is Valued: Energy storage has value potential distinct from distributed "generation" and is increasingly becoming part of the DER landscape. There are a multitude of different use cases for energy storage, ranging from islandable back-up power to load modification to operating as a multi-directional grid asset, or a combination of uses. Longer-term valuation mechanisms must consider how different use cases should be reflected either within the calculation of the rebate, or incrementally outside of it as an additional source of grid value/services.

Define Additional Value Streams: While it may be necessary to defer the calculation of some value streams to a future phase, it is a first priority task to identify additional value components and devise for how they will be studied in later phases, and take the preliminary steps that will make this possible. As described in the JSP's initial comments, additional distribution value streams that should be discussed in this context include:

1. Reduced O&M;
2. Extended equipment lifetimes;
3. Reduced sizing for equipment replacements; and
4. Enhanced awareness and grid visibility.

6. Conclusion

The JSP appreciate the opportunity to participate in the process of establishing mechanisms for unlocking the value of DERs and the methodologies associated with determining DER value. At this early stage we focus our comments as much on process as methodology because timing uncertainties and constraints and public policy issues are equally important to the more technical aspects determining DER value. Our proposal would establish a broad framework under which Illinois could pursue a transition to a value-based regime of DER compensation while also recognizing and responding to the reality that developing the finer details of such a regime and creating an environment that allows different DER market segments to grow into this regime will take time.

Round 2 Comments of the Illinois Industrial Energy Consumers ("IIEC")
Regarding the Distributed Generation Valuation and Compensation Workshop

July 28, 2018

I. Introduction

IIEC is a group of large, energy intensive, consumers of electricity, natural gas and associated delivery services in Illinois. Over the last thirty years, IIEC has participated in many regulatory proceedings before the ICC, including nearly every major rate case and policy case involving rate matters of Commonwealth Edison Company ("ComEd") and Ameren Illinois Company ("Ameren") and its predecessor companies. IIEC was also an integral part of establishing the competitive generation market and delivery rules stemming from the Electric Service Customer Choice and Rate Relief Law of 1997 and subsequent laws and Commission rules. IIEC appreciates the opportunity to provide these comments on the Distributed Generation Valuation and Compensation Workshop.

As large energy consumers, IIEC seeks to ensure that the delivery service rates that it pays are fair, reasonable, and no higher than necessary. IIEC expects that the cost of distributed generation rebates will be collected from all retail customers, through a charge imposed on the utilities' distribution delivery service bills. IIEC does not oppose the expansion of distributed generation, including solar generation, to the extent that it does not jeopardize the reliability of electric supply or delivery, or unnecessarily raise non-participating customers' costs.

II. General Comments

IIEC understands Section 16-107.6 of the Illinois Public Utilities Act ("PUA") to call for an examination of the real value of distributed generation to the "distribution system" when setting the rebate levels, not some expanded examination or ethereal assessment of alleged benefits that are not readily quantifiable or related to the distribution system.

> "*The value of such rebates shall reflect the value of the distributed generation to the distribution system at the location at which it is interconnected, taking into account the geographic, time-based, and performance-based benefits, as well as technological capabilities and present and future grid needs.*" (Section 16-107.6(e))

In this regard, IIEC agrees with the stated position of ComEd and Ameren in their comments. To establish rebate levels greater than specifically authorized by the law, and cause the inflated costs to be passed to other customers on their delivery bills would exceed the Commission's authority. Likewise, IIEC agrees with the comment of ComEd, where it states:

> "**Objective cost/benefit analysis is critical.** Regulatory policy and structural change should be guided by unbiased, objective cost/benefit analyses that correctly reflect costs to the distribution consumers and

> distribution system as a whole." (ComEd Comments at 3, emphasis in original)

Not all distribution consumers will benefit to the same degree as others from the expansion of distributed generation. For example, savings to the secondary distribution circuits will not inure to any significant degree to customers taking service at primary voltage or transmission voltage levels. Accordingly, while this workshop process is not a retail rate design matter, per se, it will be important for the Commission to recognize the varying levels of assumed benefits among customer classes when it determines the eventual recovery mechanisms.

IIEC has reviewed the June "DG Valuation and Compensation White Paper: Version 2" ("White Paper") and, as indicated below, offers some comments, ranging from editorial to substantive. One item worth discussing further here is the list of potential benefits to the distribution system, as discussed in Section 3.1 of the White Paper (pages 10 – 14). This subsection is the most relevant to the rebate determination, since it attempts to establish a framework for viewing the benefits mentioned in the statute. Specifically, the section lists and discusses the following potential benefits, by subsection. IIEC will comment briefly on each:

- Distribution Capacity Value;
- Reduction in Losses;
- Voltage Support, Operating Reserves and Other Ancillary Services; and
- Reliability and Resiliency.

II.A. Distribution Capacity Value

IIEC agrees, in theory, that expansion of distributed generation has the potential to expand distribution capacity, by possibly meeting circuit loads locally, and potentially avoiding or mitigating future circuit expansion costs. However, as properly acknowledged in the White Paper, "the presence of distributed generation may increase or decrease distribution system investments needed to meet system needs and keep the system running safely and reliably," and that in some circumstances "added costs are incurred when additional distribution investments are necessary to upgrade wires, transformers, voltage-regulating devices, control systems, and/or protection equipment." (p 10, emphasis added) Without knowing that benefits, not increased costs, will accrue, it will be difficult if not impossible to reasonably estimate net benefits.

Because of various circumstances, including compliance with safety regulations, often much of the utilities' existing distribution systems already have capacities that exceed the current circuit load levels. Thus, load reductions due to expansion of distributed generation, if any, may not always provide benefits in terms of distribution capacity value.

In addition, as a practical matter few, if any, poles, overhead or underground conductors or underground conduit will be avoided by a reduction in circuit loads. Likewise, service lines to homes and meters will not be reduced. Perhaps some distribution transformers could be of lower capacity and distribution conductor (wires) could be of slightly smaller gauge. The cost savings of these reductions may be insignificant, however.

IIEC does not necessarily agree with the assumption at page 11 that "in the absence of specific values [associated with utilities' capital expenditure plans in each geographic area and assessments of what may be deferred or avoided due to distributed generation], marginal cost of service (MCOS) studies provide a reasonable basis for calculating avoided distribution capacity value." Although MCOS studies may be useful in determining the value of distributed generation, *if it is assumed that capital expenditures will be made and are imminent*, they tell us nothing about whether or when such investments will be needed. Given the relatively long lives of distribution facilities (25 to 50 years), it is not reasonable to assume that an MCOS measure determined today is an appropriate proxy for an investment (or avoided one) to be made decades from now.

In summary, while benefits of distribution capacity value due to expanded distributed generation are theoretically possible, they are highly uncertain and, in certain cases, may be negative.

II.B. Reduction in Losses

IIEC agrees that expansion of distributed generation near load has the potential to reduce distribution losses, since electrical losses on distribution equipment are directly proportional to load. If load on parts of the distribution system is reduced, then losses on those parts would be reduced. IIEC further agrees with the statements in the White Paper that reverse power flows due to high penetration of distributed generation could increase losses (p 12) and that a determination of the benefit of losses will need to be done on a case-by-case basis, depending on feeder topology, distributed generation penetration levels and interconnection point (p 13). Accordingly, assigning a generic value to distribution losses in the rebate determination will be imprecise at best and specious at worst.

II.C. Voltage Support, Operating Reserves and Other Ancillary Services

At page 13, the White Paper identifies voltage control and operating reserves as the ancillary services most commonly associated with distributed generation. IIEC agrees that expansion of distributed generation, particularly with smart inverters, has the potential to help control local distribution voltages. Unfortunately, the White Paper provides no real insight as to how to quantify the benefits of the improved distribution system voltage control. IIEC also recognizes that voltage control is related to reliability and suggests that the Commission should take care not to double count the potential benefit of improved voltage control.

Regarding operating reserves, IIEC cautions that provision of operating reserves is typically considered a generation function and is provided through transmission services, e.g. pursuant to Schedules 5 and 6 of the FERC Open Access Transmission Tariff. Thus, while distributed generation may in fact be able to provide operating reserves, it is not a benefit to the distribution system, per se. If the distributed generation rebate value is limited to the value of distributed generation to the distribution system, as discussed above, IIEC does not believe that the benefit of improved operating reserves is properly a part of the rebate value.

With regard to other ancillary services mentioned in the White Paper, namely reactive supply, frequency regulation, energy imbalance, and scheduling, IIEC believes that, like operating reserves, these are related to the generation and transmission systems, not distribution, and generally should not be considered in determining a distributed generation rebate value.[1]

II.D. Reliability and Resiliency

IIEC generally supports the idea that expanded distributed generation has the potential to improve the reliability and resiliency of the distribution system. However, as with the other benefits discussed above, high or uncoordinated penetrations of distributed generation also have the potential to reduce the reliability and resiliency of the distribution system, if existing distribution systems become overloaded or if swings in the output of distributed generation (and thus swings in the loads on the distribution system) become problematic, through voltage fluctuations or otherwise.

IIEC observes that the White Paper does not have much information on how to value the potentially improved reliability and resiliency of the distribution system.

III. Answers to Specific Questions Posed

The Commission offered specific questions for the parties to address. IIEC does not offer an opinion on many of them, but does offer information on the following items, only. The numbering below corresponds to the Commission's original question numbers.

1. Please provide any suggested revisions to the June White Paper.

   IIEC provides comments and revisions to the White Paper as shown on Attachment 1, in redline format and with comments.

2. Regarding the different benefits of distributed energy resources, please provide input on the following:

   a. Which value streams should be included in the Section 16-107.6 DG rebate?

      As discussed in our General Comments above, IIEC believes only reasonable estimates of net benefits to the distribution system, not other benefits, are to be considered.

1 IIEC acknowledges that one of the identified ancillary services, reactive supply, in certain instances can be provided through distribution level facilities.

c. Which value streams are outside the scope of Section 16-107.6?

As discussed in our General Comments above, IIEC believes only reasonable estimates of net benefits to the distribution system, not other benefits, are to be considered.

e. How are any value streams reflected in current rate structures and how are they currently calculated?

The potential value streams associated with benefits to the distribution system of expanded distributed generation identified in the White Paper are included in the distribution rates. In addition, some of the purported benefits are actually related to generation and transmission and are included in generation and transmission rates. None of the purported value streams are calculated explicitly, as ratemaking tends to be based on cost of service, rather than benefit of service and the investments needed to provide these benefits are compensated through such cost based rates.

3. Apart from value formulas and/or specific rebate values, should candidate deferral projects, deferred distribution investment, marginal cost studies, or other information be made public?

Yes. All elements that affect the rates charged to customers should be publicly available. Information that, if revealed publicly, could pose a security risk to the system should be made available only with sufficient protections.

4. In terms of the next procedural steps prior to the initiation of the investigation pursuant to Section 16-107.6, we welcome your comments on the following:

a. Should the Commission use a designated working group process? If so, how should the working groups be structured, governed, and otherwise implemented?

IIEC recommends use of a working group, limited in size, consisting of representatives of customers, utilities, ICC technical staff and potential recipients of the distributed generation rebates. IIEC recommends that leadership for the group should be co-representatives of the two major electric utilities.

i. Are there any value streams that may take more time to develop that should be separated from value streams that may be more quickly developed?

IIEC interprets the question to refer to the value streams themselves, not the quantification of benefits for the purposes of establishing the distributed generation rebate. In either case, however, there definitely will be a difference in the time to develop. With regard to the actual value stream of the benefits related to Distribution Capacity, if any, as discussed above, the value may take

decades to manifest, as existing distribution infrastructure is replaced or expanded. Therefore, there should be a separation of value streams.

In addition, IIEC would note that the assumed lifespans and performance of the distributed generation over time should be considered. For example, if the output of a distributed generation facility is expected to degrade over time, this suggests that the value streams may likewise diminish over time.

b. Should the Commission consider using a consultant to help with developing Section 16-107.6 compensation methodologies and values?

IIEC believes that use of a consultant may be helpful if, 1) the workshop process does not yield sufficient results and 2) the ICC technical staff is unable to develop such methodologies and values.

IV. Conclusion

IIEC understands and appreciates the Commission's concern in developing a fair and reasonable distributed generation rebate level, which properly considers the benefits to the distribution system and which does not unnecessarily burden non-participating customers with inflated rebate costs. IIEC does not oppose the expansion of Distributed Generation. It recognizes in certain instances there are benefits it can provide to the distribution system and those benefits can have a value. Properly identifying and monetizing that value and returning it to the value creators is the challenge. The Commission should pursue a solution using the workshop process discussed above. IIEC hopes to be involved in that process to present large industrial users' insights and concerns. IIEC looks forward to assisting the Commission in developing a proper rebate mechanism.

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SECOND ROUND INFORMAL WRITTEN COMMENTS
OF THE COALITION TO
REQUEST EQUITABLE ALLOCATION OF COSTS TOGETHER ("REACT")[1]

The Coalition to Request Equitable Allocation of Costs Together ("REACT") appreciates this opportunity to comment on the June 28, 2018 Illinois Distributed Generation Rebate Calculation Considerations, Version 2 white paper (the "June White Paper") that was prepared by the Pacific Northwest National Laboratory ("PNNL"). As the Illinois Commerce Commission ("Commission") is aware, REACT includes large energy users who own and operate on-site generation at their facilities, as well as developers who work with large energy users and others to develop distributed energy resources ("DER").

On March 30, 2018, REACT provided Initial Comments in response to PNNL's March 1, 2018 white paper ("March White Paper"), highlighting that the scope of the investigation that the Commission has been directed to undertake is broader than simply considering the value of smaller-scale distributed generation. REACT's Initial Comments explained that there are a variety of DERs that add value to the grid, each with different characteristics; each type of DER should be compensated to appropriately reflect its full value. In particular, commercial and industrial ("C&I") customer on-site DER provides substantial additional value to the grid that is not currently recognized in the utility's rates. In addition, given that the General Assembly has directed that the State should "encourage[] the adoption and deployment of cost-effective distributed energy resource technologies and devices," as a part of this process, the Commission should identify and remove any and all regulatory burdens that unnecessarily inhibit the further deployment of DER. (P.A. 99-0906, Section 1.)

Unfortunately, the June White Paper inappropriately failed to address many of the issues addressed in REACT's Initial Comments. REACT respectfully requests that, going forward, the workshop process better reflect the broad scope of the investigation that the Public Utilities Act ("PUA") directs the Commission to undertake, and the steps necessary to better position the State to take full advantage of the opportunities DERs provide to advance the Illinois economy.

REACT's Responses to Suggested Questions

REACT has provided below its responses to three (3) of the questions the Commission posted to frame the discussion for stakeholders' Round 2 Comments:

Question # 2. What general approaches, whether they were included in the June White Paper or not, should be considered for use in Illinois?

The breadth and depth of the June White Paper was inappropriately constrained. The June White Paper asserts that it provides a "preliminary look" at distributed generation valuation methodology, taking into consideration input from the stakeholder's written comments. (*See* June White Paper at 1.) However, the June White Paper inappropriately disregarded the terms of the PUA regarding the scope of the investigation that the Commission is to undertake, ignored the bulk of REACT's Initial Comments, and failed to even consider the valuation methodology for C&I behind-the-meter DER that REACT discussed.

[1]These Second Round Comments are preliminary and necessarily incomplete, given that the Commission has not begun to have substantive discussions on a number of specific issues that are central to the investigation that the Commission has been directed to undertake. REACT reserves the right to respond to additional questions and provide additional or different Comments as this process evolves.

As REACT stated in its Initial Comments, the Commission's investigation under Section 16-107(6)(e) of the PUA is not limited to just valuing smaller "distributed generation," but "**shall include** diverse sets of stakeholders, calculations for valuing **distributed energy resource** benefits to the grid based on best practices, and assessments of present and future technological capabilities of **distributed energy resources**." (220 ILCS 5/16-107.6(e). Emphasis added.) Distributed energy is just one type of DER, which also includes behind-the-meter generation, energy storage facilities, distributed energy resource aggregation, micro-grids, and cogeneration. (NERC, "Distributed Energy Resources, Connection Modeling and Reliability Considerations," Feb. 2017 at 1, https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf (last visited March 30, 2018).)

Ameren Illinois likewise appropriately noted in its initial written comments that the determination of value to the distribution system should be guided by a "key concept" that DER is "a more widely used term that may better encompass the full breadth of technologies and applications that may be connected to the distribution grid" than the term distributed generation, and that the definition of DER should "broadly encompass any generation, storage, or other load managing resource connected to the distributed grid." (Ameren Initial Comments at 1.)

While noting Ameren Illinois' comments on DER, the June White Paper failed to even acknowledge REACT's comments on the issue. (*See* June White Paper at 2.) The June White Paper then summarily stated that it would focus on distributed generation specifically, pointing to a clause in Section 16-107.6(e) that "the value of such rebates shall reflect the value of the distributed generation." (*Id.*) While that provision notes that the values of those specific *rebates* are for "distributed generation," Section 16-107.6(e) **requires** that the scope of the *investigation* be much broader: "**The *investigation* <u>shall</u> <u>include</u>** diverse sets of stakeholders, calculations for valuing **distributed energy resource** benefits to the grid based on best practices, and assessments of present and future technological capabilities of **distributed energy resources**." (*Id.* Emphasis added.)

Section 16-107.6(e) must be read as a whole and in the context of the goals of the PUA of providing "adequate, efficient, reliable, environmentally safe and least-cost public utility services at prices which accurately reflect the long-term cost of such services and which are equitable to all citizens." (220 ILCS 5/10-102; *see also* REACT Initial Comments at 1-3.) The decision to take such a narrow interpretation of the PUA at this preliminary stage unnecessarily restricts the Commission's consideration of the "full breadth of technologies" that add value to the grid and that should be compensated commensurate with their value.

REACT also recommended that the Commission through this investigation take a number of specific additional steps to remove existing barriers to additional DER deployment. In order to actually embrace the benefits that can be achieved through DER, the Commission should:

- Revise the interconnection process to require additional transparency. The June White Paper appropriately notes that the concern regarding transparency was noted by a number of stakeholders. (*See* June White Paper at 5.) However, the June White Paper inappropriately focuses solely on the transparency of future "hosting capacity analyses," while ignoring the lack of the transparency in the utilities' current interconnection processes, which is a significant existing barrier to entry. As noted in REACT's Initial

Comments, the Commission should adopt a process in Illinois that closely mirrors that successful FERC / PJM process, which includes a transparent public queue and requires interconnection studies and agreements to be filed with the regulator and be made publicly available. (*See* REACT Initial Comments at 6.) The Commission also should develop clear guidelines with respect to the type, scope and level of acceptable interconnection costs; require utilities to provide full and complete supporting documents for their cost estimates and fully justify any deviation from those estimates; create a process for utilities to establish meaningful time lines for project completion; and establish a hotline to resolve commercial issues. (*See id.*)

- Empower customers to directly sell DER onto the grid. The General Assembly has recognized that the investment in smart grid technologies "**empowers the citizens of this State to directly access and participate** in the rapidly emerging clean energy economy while also presenting them with unprecedented choices in their source of energy supply and pricing." (P.A. 99-0906, Section 1.) Although some customers with on-site generation currently may use the PJM demand response program to mitigate their capacity risk, they currently must use third-party demand response service providers to access the market; only "QFs" can directly sell the output of their facilities. It would be more efficient if customers with all forms of DER were able to directly access those markets themselves.

- Investigate the circumstances under which customers should be entitled to self-build distribution system upgrades and interconnection facilities, consistent with the utility's requirements.

- Acknowledge that all DER is subject to either ICC or FERC oversight and regulation, and that batteries are to be treated as generation for purposes of the interconnection processes. The Commission should create a bright line definition to ensure that lower voltage facilities that qualify to become transmission under the FERC seven factors test do indeed become transmission. Jurisdiction over DER should be complete and seamless; there should be no suggestion that some form of DER "falls through the regulatory cracks."

- Recognize in its regulations that payments to the utilities for Commission-jurisdictional DER interconnection costs are not taxable income. Inappropriate tax treatment of these costs artificially inflates the upfront project costs and discourages otherwise cost-effective deployment of DER.

- Establish appropriate market rules that recognize the multiple, separate functions of entities supporting the grid. Specifically, the Commission should recognize that the same entity cannot provide more than one of the following functions: (1) own, operate and maintain the distribution system; (2) act as the distribution system operator, facilitating the market for the distribution system; and (3) own or operate DER.

It would be entirely inappropriate for the Commission to accurately calculate the benefits of DER only to have the actual deployment of additional DER thwarted by these types of administrative obstacles. Therefore, REACT respectfully requests that, as part of this investigation, the Commission consider the value of all DERs to the distribution system and take the additional steps necessary to appropriately facilitate additional development of DER.

Question #3. Regarding the different benefits of distributed energy resources, please provide input on the following:

1. Which value streams should be included in the Section 16-107.6 DG rebate?

As discussed in REACT's Initial Comments, the unique value associated with commercial and industrial ("C&I") behind-the-meter DER should be recognized by the Commission. Behind-the-meter DER includes cogeneration, combined heat and power, reciprocating engines, and other generation or energy storage systems installed on the customer's premises. These DER systems are non-utility scale technologies used to provide all or a portion of the customer's electricity supply needs, thus avoiding the consumption of electricity from the grid. By displacing electricity delivered by the transmission and local distribution utilities, behind-the-meter DER reduces the need for electricity to be delivered by the utility, thus reducing the need for new generation capacity and reducing transmission and distribution capital costs for upgrades, as well as maintenances expenses.

Question #4. Regarding the calculations of the various value streams, if not included in your general response, please provide input on the following:

d. What distribution system data, pricing data, forecasts, analysis results, formulas, or other information is necessary to compute the value of each value stream that should be separately compensated pursuant to Section 16-107.6?

The valuation of the C&I behind-the-meter DER should include both the displaced energy "commodity" costs, as well as all fixed "avoided" costs associated with transmission, distribution and capacity. Providing transmission and capacity credits for DER has already been accepted by several states, as has the concept of considering non-wires alternatives to distribution expansion. (*See* June White Paper at 4, 16-17; March White Paper at 9-13.)

REACT respectfully requests that the Commission calculate the C&I behind-the-meter DER valuation to accurately reflect these avoided costs and the value provided to the grid. For each MW of on-site generation, the behind-the-meter DER should receive an annual credit equal to the annual per MW transmission and capacity related charges. These charges are the costs that are being avoided by the on-site generation of that MW. As discussed in detail in REACT's Initial Comments, REACT has calculated that annual cost to be approximately $130,000 per MW for customers in the ComEd service territory beginning in June 2018; $120,000 per MW beginning in June 2019; and $110,000 per MW beginning in June 2020. Given that a typical C&I on-site generation system has a capacity of approximately 5 MW, the value the behind-the-meter DER is providing is significant: approximately $500,000 per year.

Conclusion

REACT appreciates the opportunity to present these Second Round Comments, and looks forward to continuing to work with the Commission and interested stakeholders in this process to develop equitable and accurate rates that reflect the unique value that C&I behind-the-meter DER provides to the grid as well as to develop additional fair regulations that will encourage cost-effective DER.

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