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Illinois Distributed Generation Rebate – Preliminary Stakeholder Input and Calculation Considerations

October 2018

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Prepared for the 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.

Acknowledgments

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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).

[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.

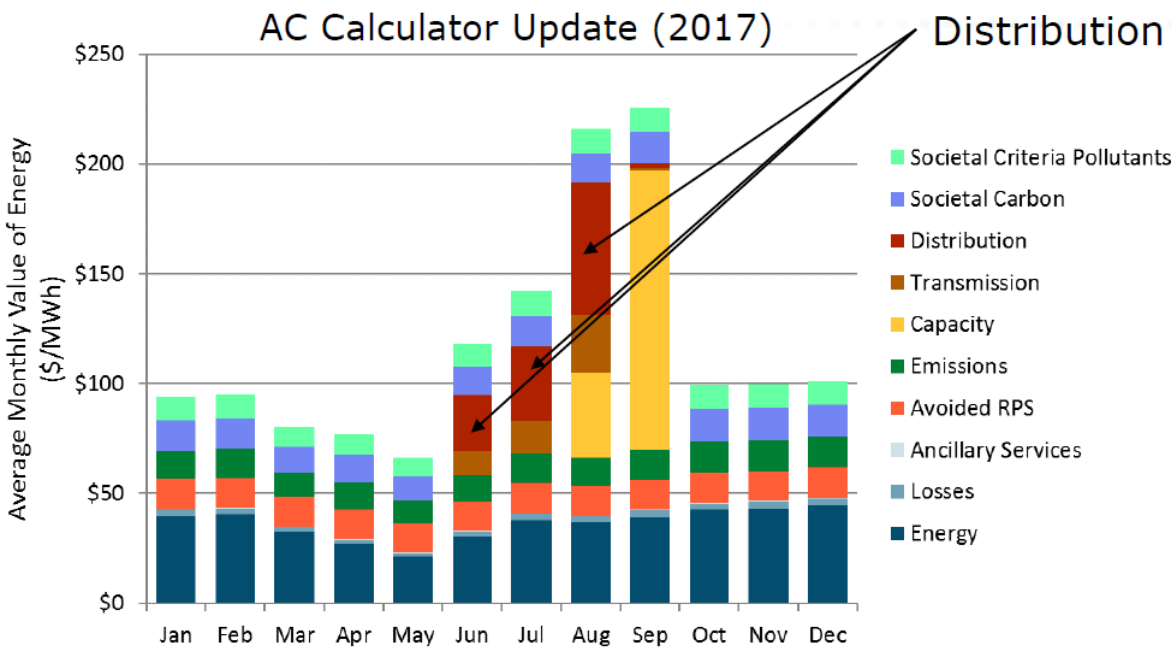

Figure 1. Average Monthly Value of Energy in California (E3 2017)

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 with distributed generation and without 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.

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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.

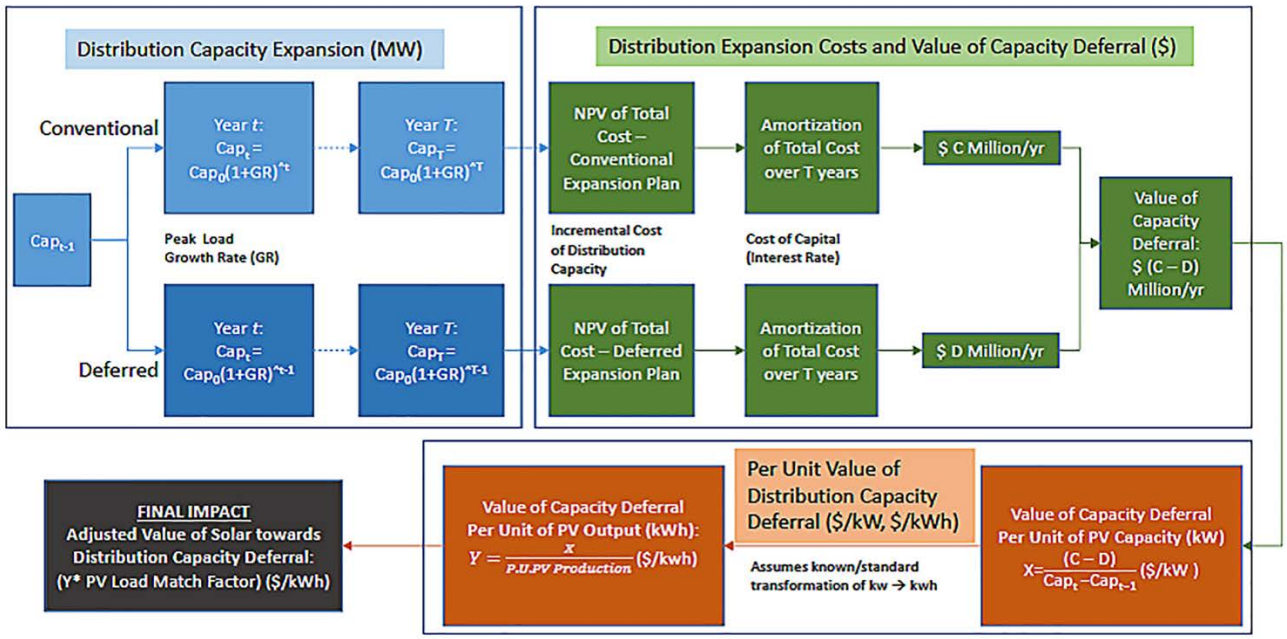

Figure 2. Minnesota Distribution Capacity Value Calculation

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.

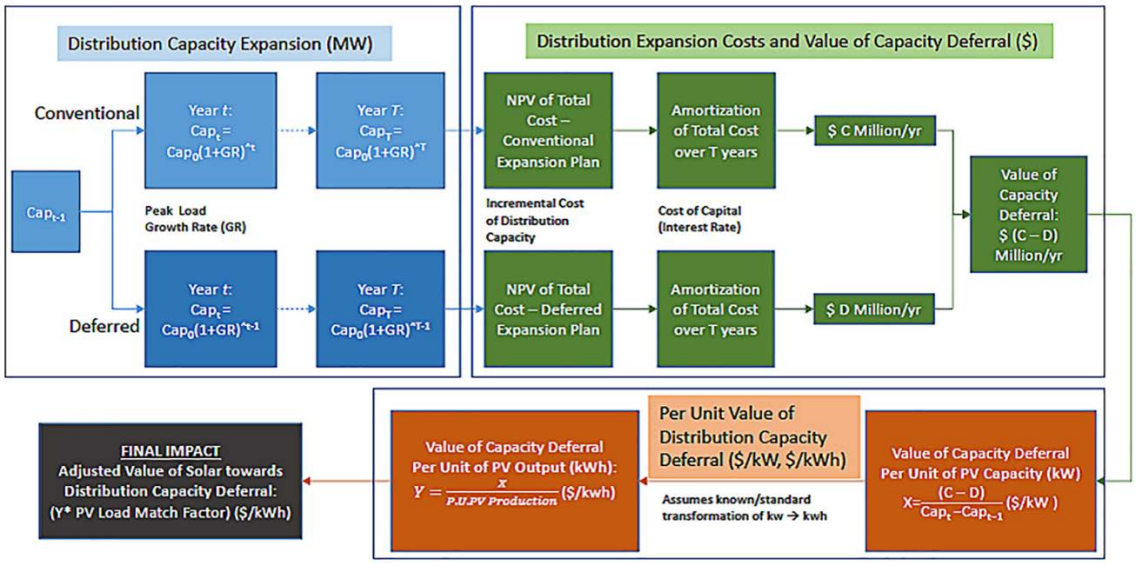

Figure B.1. Minnesota Distribution Capacity Value Calculation

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 Standard PV degradation value Metered production data from PV plants, Technical applications of PV plants, or PV fleets outside of utility territory US Treasury (escalation rate)	VOS Data Table 0.50% 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 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 (capacity)	Capital cost of generation to meet peak load	Avoided Generation Capacity Cost	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 (capacity)	Capital cost of generation to meet planning margins and ensure reliability	Avoided Reserve Capacity Cost	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%	
			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%	
Required (environmental)	Externality costs	Avoided Environmental Cost	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%	
			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

Appendix D

Stakeholder Comments

See separate file.

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