ENVIRONMENTAL LAW & POLICY CENTER

Protecting the Midwest's Environment and Natural Heritage

December 16, 2019

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

RE: MPSC Case No. U-20147

Dear Ms. Kale:

Please find attached Comments of Vote Solar and the Environmental Law & Policy Center regarding Docket U-20147 (In the matter, on the Commission's own motion, to open a docket for certain regulated electric utilities to file their distribution investment and maintenance plans and for other related, uncontested matters.)

Please contact me if you have any questions.

Sincerely,

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

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to open a docket for certain regulated electric utilities to file their distribution investment and maintenance plans and for other related, uncontested matters.	))))))	Case No. U-20147

COMMENTS OF ENVIRONMENTAL LAW & POLICY CENTER AND VOTE SOLAR

INTRODUCTION

Following the Commission's November 21, 2018 order in this docket, in which it suggested a "technical conference" with utilities, stakeholders and experts, Commission Staff convened a series of stakeholder discussions on electric utility distribution planning between June and November of 2019 (constituting the "technical conference"). Those stakeholder discussions included presentations by subject-matter experts on topics including non-wires alternatives, cost-benefit analysis, hosting capacity analysis and reliability and resilience metrics. Over the course of those discussions, several interested stakeholders—including the Environmental Law and Policy Center (ELPC) and Vote Solar—provided oral and written input on the topics that were covered during the sessions.[1] Commission Staff will prepare and file a report in this docket compiling and summarizing all stakeholder input from the distribution planning discussions and provide recommendations to the Commission that will inform the utilities' second round of distribution plans (to be filed in June 2021).

ELPC and Vote Solar commend the Commission Staff for organizing and facilitating stakeholder discussions on distribution planning and believe these discussions have the potential to translate to stronger utility distribution planning processes (and plans) going forward. ELPC and Vote Solar also appreciate the Staff's invitation to provide additional comments ahead of the preparation of its report. Through their written comments in this docket and their participation in the stakeholder sessions, ELPC and Vote Solar have consistently expressed their concerns with the utilities' current distribution planning processes and offered recommendations on ways in which to strengthen those processes. ELPC and Vote Solar will not repeat all of those concerns and recommendations here, and instead offers these brief comments to: 1)

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[1] *See, e.g.* Comments of the Environmental Law & Policy Center, Natural Resources Defense Council and Vote Solar, Docket U-20147, Sept. 11, 2019.

direct utilities, the Commission and Staff, and interested stakeholders to additional useful resources relevant to the continuing evolution of electric distribution planning in Michigan, and 2) address additional issues arising from the stakeholder process that we have not previously addressed.

JOINT COMMENTERS

ELPC is a not-for-profit public interest environmental organization that works to achieve cleaner air, advance clean renewable energy and energy efficiency resources, improve environmental quality, protect clean water, and preserve natural resources in Michigan and the Midwest.

Vote Solar is a non-profit, non-partisan, grassroots organization working to fight climate change and foster economic opportunity by bringing solar energy and other distributed energy resources (DER) into the mainstream.

HOSTING CAPACITY ANALYSIS

At various points during the series of distribution planning stakeholder discussions, participating stakeholders raised the question of how much a hosting capacity analysis would cost—the answer to which would necessarily inform the value of an HCA to customers and other stakeholders. During the November 19, 2019 stakeholder session, representatives from DTE and Consumers Energy attempted to address this question, and discussed the costs associated with various levels of hosting capacity analysis (HCA) based on joint-utility analysis; industry benchmarks; and an RFP that DTE has issued for a hosting capacity analysis pilot. Briefly, that discussion suggested that at the lowest end, an “Area Based Assessment” could cost in the range of $0.5-1 M, while at the highest end, a “Feeder Based Model Assessment with Verification” could cost in the range of $40M.

We appreciate the utilities presentation and effort at analyzing the cost of an HCA, and appreciate in particular that DTE has issued an RFP to gather information on the cost of implementing HCA. We would be interested to learn more about the scope of the RFP and the proposals that were presented to DTE. ELPC and Vote Solar continue to believe that HCA not only provides important information for customers, developers and policy makers, but also provides a benefit to the utility in collecting, organizing and databasing information about its own system.

Based on our experience in working with utilities in other states, however, we believe the costs that DTE has estimated for its HCA pilot to be too high and grossly out of sync with industry experience. We would note that in Dominion Energy's recent grid modernization filing in Virginia, the utility requested $156,000 of capital and $447,000 of O&M over 10 years to initially develop and regularly update its HCA.[2] Likewise, in its November 1, 2019 compliance filing on its 2019 Hosting Capacity Report, Xcel Energy (Minnesota) estimated the costs associated with its hosting capacity analysis as follows:

> As directed by the Commission's August 2019 Order, we estimated the costs for preparing the 2019 HCA and Report. Overall, we estimate that the total cost for the 2019 HCA was over $300,000. This includes engineering staff time from June 2019 through October 2019 (approximately 1,600 hours), but excludes time spent prior to June 2019 for such tasks as stakeholder engagement; preparation for the analysis; hiring and training of multiple interns; and various other activities surrounding the DRIVE tool and collaboration with EPRI. This estimate also excludes the effort of other departments outside of Engineering, such as Regulatory and Legal. We have incurred additional costs to conduct the separate EPRI analysis of 95 feeders with no hosting capacity ($50,000), to acquire the DRIVE tool in 2016 ($250,000) and to participate in the DRIVE User Group ($30,000).
>
> If we were required to update the HCA more frequently, we believe each round of updates would cost slightly less than $300,000, but still be substantial. While we would not need to prepare a separate HCA report, we would still need to rebuild feeder models and update system data for each update.[3]

The Dominion and Xcel examples illustrate that Consumers' and DTE's estimates of the costs associated with an HCA are off by at least an order of magnitude. ELPC and Vote Solar encourage the utilities to continue to consult subject-matter experts and other utilities who have conducted HCA, and revise/improve their HCA cost estimates accordingly. The utilities, as well as the Staff and the Commission, should not rely on the cost estimates that DTE and Consumers presented during the November 19, 2019 distribution planning stakeholder discussion.

INTEGRATED DISTRIBUTION PLANNING

During the September 18, 2019 stakeholder session, Curt Volkmann (President, New Energy Advisors, LLC) presented on the topic of integrated distribution planning (IDP), and explained how IDP diverged from traditional utility distribution planning

[2] Va. Elec. and Power Co., Va. Corp. Comm'n, Case No. PUR-2019-00154, Dir. Test. of Robert S. Wright, Schedule 1, at 2 (Sept. 30, 2019).
[3] Xcel Energy, In The Matter Of The Xcel Energy 2019 Hosting Capacity Report Under Minn. Stat. § 216B.2425, Subd. 8, Case No: 19-685, Hosting Capacity Report at 9 (November 1, 2019).

processes. Mr. Volkmann also referred the Commission to a report[4] he authored in conjunction with Gridlab which describes in detail each of the key components and values of IDP.

More recently, the Mid-Atlantic Distributed Resources Initiative (MADRI) released a report[5] tailored specifically for utility regulators on the topic of IDP. While the report is tailored to assist utility commissions in the restructured jurisdictions that participate in MADRI, several of the topics covered in the report are relevant to this Commission's (and Staff's) consideration of the necessary evolution of distribution planning in Michigan, including: Commission authority to require or approve an IDP, Commission staffing necessary to oversee IDP, and potential synergies with other planning processes including IRPs. In order to provide Staff and this Commission with an additional resource that explains how regulators, utilities and other stakeholders can work in coordination to implement IDP, ELPC and Vote Solar offer the MADRI report as **Attachment A** to these comments.

LOCATIONAL VALUE

In his September 18, 2019 presentation to the distribution planning stakeholder group, Mr. Volkmann explained that "Disclosure of Grid Needs and Locational Value" is a key capability under Integrated Distribution Planning. While the stakeholder discussions to date did not cover locational value in depth, recognizing that this topic will be of increasing importance in Michigan in the future, the Commission Staff has expressed interest in understanding how utilities and regulators in other states are approaching that topic.

Illinois Locational Value

In Illinois, the Future Energy Jobs Act in 2016 set a process for transition from net metering to a new mechanism that includes a distributed generation rebate. As part of this policy, FEJA includes a number of mechanisms for encouraging investment in DERs, among which is a rebate to distributed generation (DG) owners, intended to eventually replace net metering of distribution charges.

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[4] Volkmann, Curt. GridLab. "Integrated Distribution Planning: A Path Forward" available at https://gridlab.org/works/integrated-distribution-planning/.

[5] Mid-Atlantic Distributed Resources Initiative, "Integrated Distribution Planning for Electric Utilities: Guidance for Public Utility Commissions." October 2019. Available at: https://www.madrionline.org/wp-content/uploads/2019/10/MADRI_IDP_Final.pdf.

At a minimum, that rebate must compensate DG owners for the value of the utility's ability to control the associated smart inverter for reliability purposes during "distribution system reliability events."[6] However, the law sets out a process for determining "additional uses" of the smart inverter that must be separately compensated, as well as for "valuing distributed energy resource benefits to the grid based on best practices, and assessments of present and future technological capabilities of distributed energy resources." The law further explains that "the value of such rebates shall reflect the value of the distributed generation to the distribution system at the location at which it is interconnected, taking into account the geographic, time-based, and performance-based benefits, as well as technological capabilities and present and future grid needs."

FEJA also set a threshold at which point the Illinois Commerce Commission is directed to begin a study to identify those values at 3% distributed generation penetration so that the state would be ready to transition from net metering to a DG rebate when penetration levels hit 5%.

In anticipation of that investigation, the Illinois Commerce Commission convened the Distributed Generation Valuation and Compensation Policy Workshops in 2018 to explore the issues and challenges of determining locational value in the distribution system and compensating distributed resources for that value.[7] The ICC retained the Pacific Northwest National Laboratory to facilitate the workshop and produce a report on the proceedings. In October 2018, PNNL released *Illinois Distributed Generation Rebate – Preliminary Stakeholder Input and Calculation Considerations*. This report provides valuable information that could be useful to the Commission (and Staff) as it considers how to incorporate locational value considerations as a part of distribution planning, and as such, we have included the report as **Attachment B** to these Comments.

CONCLUSION

ELPC and Vote Solar appreciate the Commission Staff's consideration of these comments and look forward to reviewing the Staff's forthcoming report in this proceeding.

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[6] 220 ILCS 5/16-107.6(b).
[7] Distributed Generation Valuation and Compensation Workshops, March 1, 2018 and June 28, 2018. https://www.icc.illinois.gov/workshops/Distributed-Generation-Valuation-and-Compensation-Workshops

Attachment A

Integrated Distribution Planning for Electric Utilities: Guidance for Public Utility Commissions

October 2019

ABOUT MADRI

The Mid-Atlantic Distributed Resources Initiative (MADRI) seeks to identify and remedy retail and wholesale market barriers to the deployment of distributed generation, demand response, energy efficiency and energy storage in the Mid-Atlantic region.

MADRI was established in 2004 by the public utility commissions of Delaware, the District of Columbia, Maryland, New Jersey and Pennsylvania, along with the U.S. Department of Energy (U.S. DOE), U.S. Environmental Protection Agency (EPA), Federal Energy Regulatory Commission (FERC) and PJM Interconnection. The public utility commissions of Illinois and Ohio later became active participants. MADRI meetings are organized and facilitated by RAP, with funding from U.S. DOE. MADRI's guiding principle is a belief that distributed energy resources should compete with generation and transmission to ensure grid reliability and a fully functioning wholesale electric market. MADRI provides a venue to identify and consider different perspectives and possible solutions to distributed energy resource challenges in a collaborative setting, outside of contested cases and hearing rooms. MADRI meetings are free, open to all stakeholders and the public and webcast live for those who cannot attend in person.

ACKNOWLEDGMENTS

This white paper was drafted for MADRI by a committee of volunteers, with oversight and editing by the Regulatory Assistance Project (RAP) and the MADRI steering committee. The following individuals contributed to the report:

- Sara Baldwin
- Dan Cleverdon
- Kerinia Cusick
- Hilal Katmale
- Molly Knoll
- Lori Murphy Lee
- Alex Lopez
- Janine Migden-Ostrander
- Jeff Orcutt
- John Shenot
- Jessica Shipley
- Bill Steigelmann

In addition to the contributors, the MADRI steering committee, and other staff from the public utility commissions participating in MADRI, peer review and helpful comments on the report were generously provided by Paul Alvarez, Chris King, Grace Relf, and Carl Linvill.

CONTENTS

EXECUTIVE SUMMARY

The modern electric power system is undergoing a sea change that is transforming the generation, distribution and consumption of electricity. In particular, the integration of distributed energy resources (DERs)[1] into the electric power system is profoundly changing how we plan, build and operate the system. These new resources pose a challenge and an opportunity for distribution utilities, transmission system operators, retail energy suppliers, and regulators.

This manual is designed to assist utility commissions in the restructured jurisdictions that participate in the Mid-Atlantic Distributed Resources Initiative (MADRI) with guiding and overseeing the development of integrated distribution plans (IDPs) for electric utilities. Commissions in other states may also find it useful. In restructured jurisdictions, commissions generally have limited authority over generation and transmission but retain full jurisdiction over distribution services and rates. This naturally leads those commissions to focus on the distribution system. Even so, most commissions have until recently given little or no scrutiny to the details of distribution system *planning*.

IDP is a process that systematically develops plans for the future of a distribution grid using inputs supplied by the electric utility, the commission and interested stakeholders. The planning process is "integrated" in the sense that all possible solutions to distribution system needs are considered. The objective of the final plan is a distribution system that operates for the public good, meeting the objectives set out by stakeholders in a cost-effective manner. Over the long term, the IDP process should reduce costs, improve efficiency and point the way toward a more sustainable distribution grid — one that is safe, secure, reliable and resilient.

This manual addresses:

- Options and issues for establishing and overseeing a formal IDP process for electric utilities through regulatory action;
- Steps in the process of developing an IDP;
- Content of an IDP filing;
- Challenges for developing and implementing an IDP and potential solutions; and
- Technical considerations for planners.

Establishing a Formal IDP Requirement Through Regulatory Action

Commissions that wish to establish a formal IDP requirement will need to consider their statutory authority to administer such a requirement and the type of regulatory proceeding that will best serve their purposes. They will also need to make key decisions on a variety of procedural questions about the scope of the planning requirement, stakeholder participation, and

[1] The term DER is broadly used but may be defined differently in the statutes, regulations or policies of each jurisdiction. The term virtually always encompasses behind-the-meter distributed generation (DG) and electricity storage. In some jurisdictions, it may also include some combination of demand response (DR), energy efficiency (EE), electric vehicles (EVs) and in-front-of-the-meter generation or storage resources that are interconnected at distribution voltages. Microgrids, which typically rely on a combination of DERs, are sometimes considered to be DERs unto themselves. This guidance manual generally includes all these types of resources in its definition of DERs, with the understanding that definitions in some jurisdictions may be narrower.

other issues. And finally, the Commission will want to consider whether and how to coordinate its work on IDP with other planning processes and regulatory proceedings.

Commission Authority

Most states provide their commissions with general supervisory authority over all business aspects of regulated utilities as they relate to costs and quality of service. In this regard, a clear argument can be made that supervision over distribution planning is a vital component of this authority. Fundamentally, IDP is designed to ensure that investments in the utility distribution system ensure reliability, are built to be resilient, and employ least-cost options. But utilities must also enable the safe interconnection of DERs by customers and third parties and strive to optimize the use of new resources and grid technologies while reasonably balancing the risks and opportunities. Some commissions may take a narrower view of their authority to oversee and guide distribution planning and may want more specific statutory language referencing IDP. In this case, passing legislation authorizing commission involvement in and oversight of integrated distribution system planning would be necessary.

Type of Commission Proceeding

The commission has several options for considering whether and how to develop IDPs: an issue-based investigation or workshop, a rulemaking, a utility-specific contested case, or some combination of these proceedings. Some jurisdictions may opt for a more informal workshop or investigation to introduce the subject to stakeholders and receive input. This can be a productive way to learn about best practices and the pitfalls to be avoided and may be less costly (in terms of the time and human resources required) than a more formal proceeding. With a more formal process, there are a range of options. Some jurisdictions may wish to promulgate binding regulations, while others may opt for guidelines that are advisory and not enforceable.

Developing some form of consistent framework for the filing of an IDP that must be followed within each jurisdiction is important for several reasons. It ensures that the commission and stakeholders or intervenors receive the initial level of detail required to review a utility plan. It also requires a careful and thorough process by the utility to develop a plan. Furthermore, it creates uniformity in utility filings, making it easier for commission staff and the public to review them.

Regulations on an IDP process can include both the process and the substance of the filing. An IDP case filing allows the commission to review and investigate the plans of each utility under its jurisdiction to upgrade its distribution system. Having regulations in place prior to the filing provides a road map to ensure each utility initially provides all information that is necessary for the commission to begin its review and ultimately render a determination as to the reasonableness of the plan prior to any expenditures taking place.

Key Commission Decisions Regarding an IDP Proceeding

At the outset of any IDP proceeding, the commission will need to make several key decisions that shape the level of effort and roles of all parties and how the completed IDP will be used.

First, the commission must decide whether to implement IDP one utility and one case at a time or through a joint proceeding involving all regulated utilities. Taking each case one at time may allow for a deeper dive into issues and consideration of attributes specific to each utility. A joint proceeding could produce a more consistent statewide approach to planning.

Second, the commission must decide and clearly explain the types of DERs that should be considered by utilities in the IDP process. To be used as an effective tool, an IDP needs to be comprehensive in terms of examining the entire grid and all the potential options for improving the grid from a reliability, resilience and cost effectiveness standpoint.

Third, the commission must decide on the length of the planning horizon, the timing of plan filings, and the frequency of plan updates. Based on practices observed to date, an IDP should probably cover a five- to 10-year planning horizon, at a minimum, though there are examples that reach out as far as 30 years. Where a state has multiple utilities subject to IDP filing requirements, the commission may choose to stagger the timing of each utility's initial planning process to avoid creating a strain on commission staff and stakeholder resources and to maintain their ability to review and analyze the filing. Given the rapid pace of change in the power sector, a commission might want to consider requiring relatively frequent updates to each utility's IDP — perhaps even annual updates. However, preparing, reviewing and evaluating an IDP is a considerable undertaking, therefore some commissions will find that two or three years between filings is appropriate. Commissions will want to reserve the right to order a complete or modified IDP in between the scheduled updates as may be warranted. Commissions will also want to consider whether to align the timing and frequency of IDP filings with related efforts, such as integrated resource plan filings, energy assurance plans, energy master plans, etc.

Fourth, the commission will need to decide how to involve stakeholders, including other government agencies (e.g., the state energy office). Having stakeholder participation increases transparency and creates more confidence in the commission's processes and decisions. At a minimum, stakeholders should have the opportunity to review and comment on a filed IDP. In addition, commissions may find it reasonable and in the public interest to order utilities to engage expert stakeholders collaboratively, early in the process, before anything is filed with the commission. Some commissions might even wish to appoint an independent subject matter expert to *lead* the stakeholder engagement activities.

Fifth, the commission must decide whether a utility filing should be informational or subject to a commission approval that binds the utility to the planned course of action. If the former approach is chosen, the commission "acknowledges" that an IDP was submitted in conformance with established legal requirements but does not formally review or approve the content of the plan as it would using the latter approach. When considering the approval approach, commissions may be concerned that as the plan ages it could lead to utility actions that no longer reflect the best options available to the utility at the time of each implementation decision. To resolve this concern, the commission can note in an order or in its rules that approval of an IDP still requires that the utility's actions be reasonable and prudent at the time each action is taken to ensure cost recovery. Moreover, the rules or guidelines can include a process if there has been a significant lapse of time between approval of an IDP and the implementation of an aspect of the plan.

Content of a Commission Order Accepting or Approving an IDP

If an IDP is considered under a contested case hearing procedure that requires commission approval, a commission will need to issue a written order to memorialize its decision. The order should contain a recitation of the record and a review of the relevant statutes and regulations. These recitations should include a synthesis of the relevant issues and positions of the parties. These recitations summarize and analyze the administrative proceedings and are useful to aid a reviewing court. The relevant portions of the commission's decision will be the findings of fact relevant to each issue and the conclusions of law that follow from those facts. The result of these factual findings and legal conclusions will determine the fate of the IDP under consideration: approval (with or without modification) or denial (with or without an opportunity for revision). Where a commission approves an IDP, the order should outline any relevant next steps or opportunities for further review. The key consideration should be an order sufficiently detailed to allow implementation without additional commission input.

A commission can also approve an IDP with modifications. In this situation, the modifications should be clearly delineated and include sufficient direction for stakeholder implementation. Alternatively, a commission may deny an IDP, either with or without the opportunity for revision. Denial without the opportunity for revision rejects the proposed IDP but does not preclude future filings. As such, the denial should identify the grounds for denial, such as factual inadequacy, statutory barriers or a party's failure to sustain a burden of proof. Denial with direction to modify the IDP will provide stakeholders or parties to the proposal with an opportunity to revise and resubmit the current plan. In this situation, it is essential for the commission to provide guidance on where the existing proposal fell short so that parties may target their efforts toward modifications that will satisfy the commission.

The commission can also expect to see the results of the IDP in future rate cases. It is uncommon for a commission to preapprove cost recovery of distribution assets before they are used and useful in serving ratepayers. Thus, the implementing utility will need to seek recovery of the infrastructure elements of the IDP in a future rate case. This will give the commission the opportunity to review the implementation of the IDP for prudence and reasonableness.

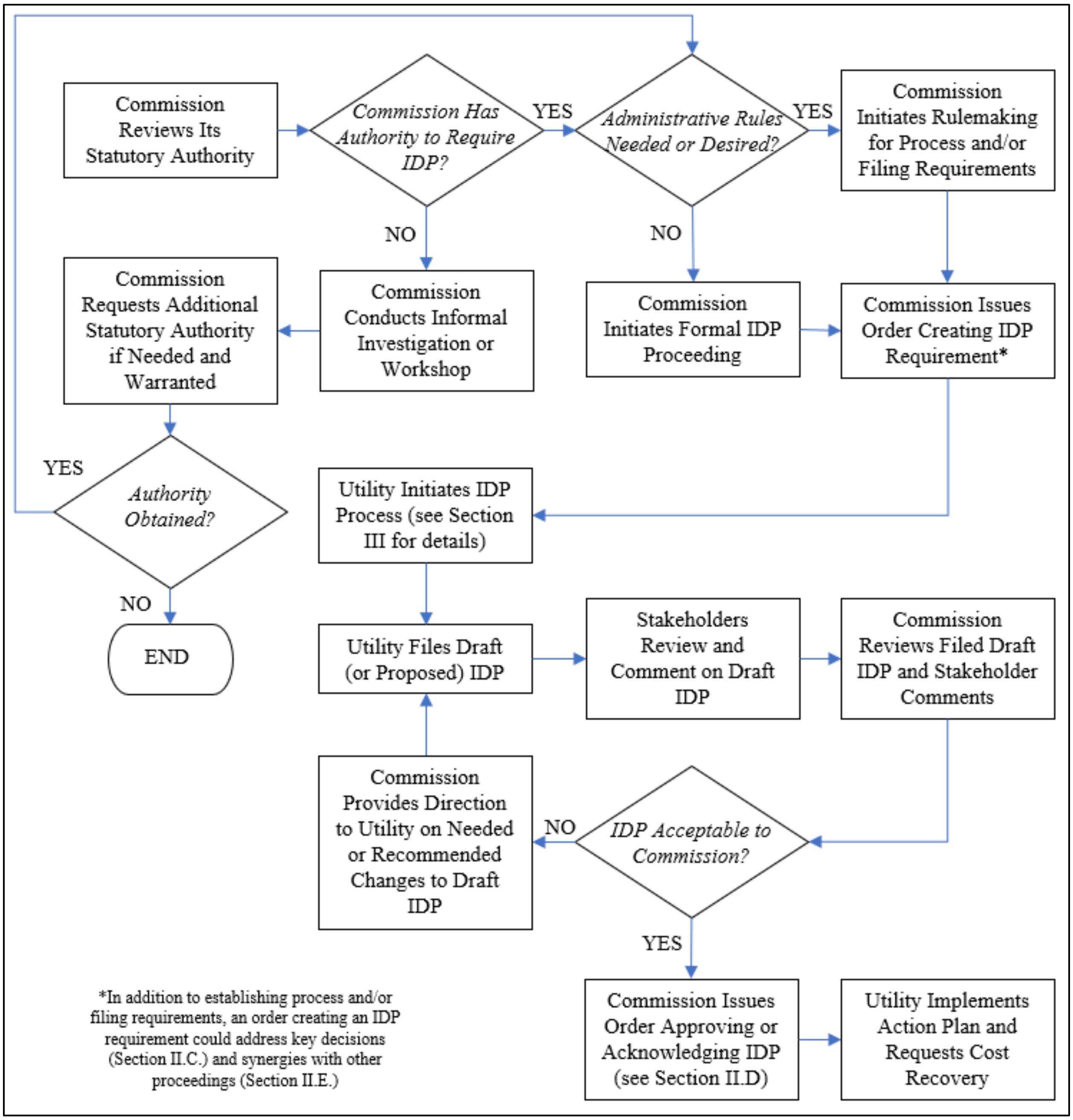
Potential Synergies with Other Electric Utility Planning Processes and Regulatory Proceedings

There are a variety of regulatory and planning issues that are not essential to an IDP process but may have a bearing on the inputs or outcomes. Commissions may wish to address some or all of these issues in concert with the decision to impose an IDP requirement: grid modernization initiatives, DER interconnection standards and procedures, the creation of a distribution system operator, changes to the electric utility business model and alternative ratemaking options, and resource or transmission planning processes.

Summary of the Commission Oversight Process

Figure ES-1 presents a flowchart summarizing the generic steps a commission might take in the process of developing and implementing an IDP requirement. Because the statutory authorities and institutional norms of every commission are unique, Figure 1 should be viewed simply as an illustrative example.

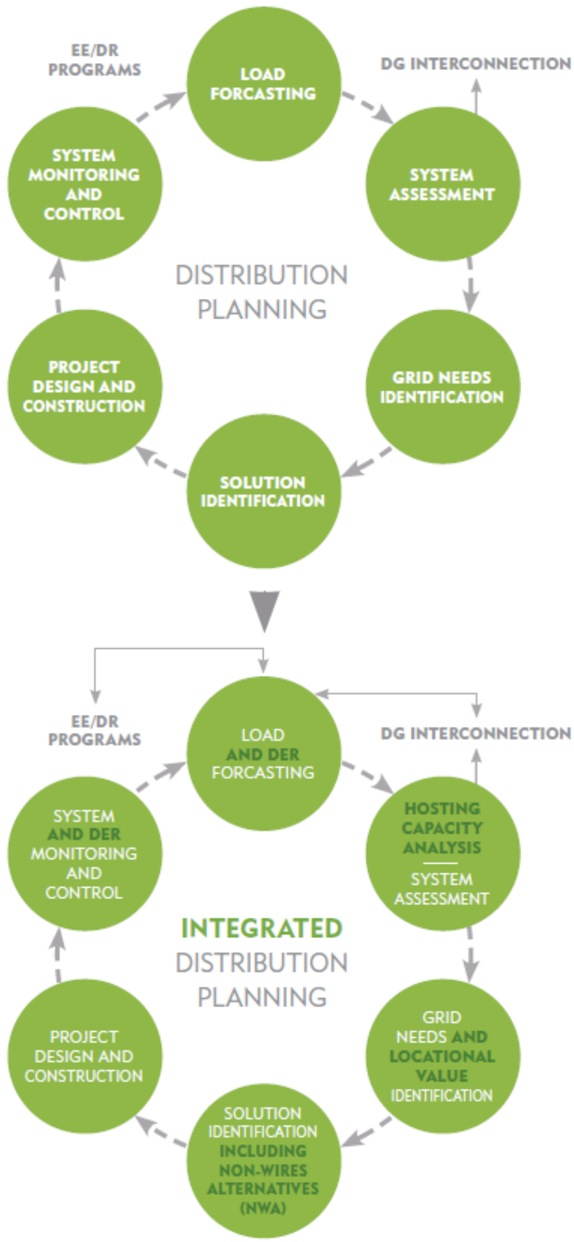
Figure ES-1: Commission Oversight of an IDP Requirement



Process for Developing an IDP

In most cases, regulatory commissions that adopt a formal IDP requirement will want to prescribe, or at least outline, a *process* for the development of such plans by utilities. Figure ES-2 illustrates how a typical distribution planning process, shown at the top of the figure, compares to an IDP process as shown at the bottom of the figure. The most essential factor that separates an IDP from a traditional distribution planning process is the integrated consideration of all possible solutions to identified needs. The goal remains to find the least costly, sufficiently safe and reliable option for ratepayers, but in IDP the preferred option may or may not include transmission or distribution infrastructure and may or may not be utility owned.

Figure ES-2: Comparison of Typical Distribution Planning Process and IDP[2]



[2] Volkmann, C. (2018). *Integrated distribution planning: A path forward*. GridLab. Retrieved from: https://gridlab.org/publications/

The planning process shown in Figure ES-2 begins with the creation of forecasts of load and DER deployment for the utility service territory, which when combined result in a net load forecast. Forecasting is foundational to the IDP process because it defines the needs of the system over the planning period. Traditional forecasting tools have focused on customer load growth rather than DERs and mainly relied on demographic and economic data and energy usage trends. However, as DERs become more common, new models become necessary to accurately forecast DER adoption trends and their impact on future net loads. Because the hallmark of an IDP process is granularity, the forecasts will need to be spatially and temporally differentiated to enable a proper assessment of system needs and potential solutions.

The second major step in the planning process is to characterize the capabilities and limitations of the existing distribution system. This requires a detailed review of the capacity of existing infrastructure, as well as known problems, limitations and areas of concern. This step also includes (or should include) an assessment of the hosting capacity of the existing distribution system. Because system conditions and hosting capacity can vary from one line segment to the next, the assessment must be very detailed and spatially granular.

In the next step, the assessment of current system capabilities is compared with the forecasts of load and DER deployment (or net load) to identify locations on the distribution system where the forecasted needs of customers will exceed existing capacity and capabilities. At the same time, this analysis can also identify locations where deployment of additional DERs or traditional assets would have the greatest value. The tools for this include software for power flow analysis, power quality assessment, and fault analysis. Power flow analysis identifies the operational characteristics of the existing and planned distribution grid, including how conditions change in relation to customer load and DER adoption scenarios. Power quality assessment studies the impact to power quality of increased penetration of intermittent renewables and inverter-based DERs on the distribution system, including voltage sag and harmonic disturbances. Fault analysis is used to identify anomalies in the flow of current on the distribution system. Advanced optimization tools are being developed to identify the optimal size, location and capabilities of DERs that can provide grid services.

After identifying forecasted grid needs, the planning process turns to a search for least-cost solutions to satisfy those needs. The essence of an IDP, and what sets it apart from a traditional distribution system planning process, is the *integrated* approach. All options to address forecasted needs should be considered on fair and equal footing. When all the suitable options have been assessed, a preferred solution or set of solutions can be chosen based on consideration of costs, capabilities, timing, uncertainties and risks.

Following any required stakeholder review or regulatory approvals of the IDP, the utility will begin to implement the near-term projects and actions identified in the plan. Some types of projects (e.g., construction of a new substation) may require additional preconstruction approvals from the commission, from environmental regulators, or from local officials. After each project or action is completed, and on an ongoing basis, the utility will need to monitor and report to the commission on system conditions to determine if the system need has been met and to identify new capacity constraints to address in future updates to the IDP.

Content of an IDP

The key content elements of an IDP include a description of the current system, a summary of planned retirements and committed future resource additions, a load and DER forecast, a hosting capacity analysis, a needs assessment and risk analysis, an evaluation of options for meeting forecasted needs, an action plan, and a summary of stakeholder engagement.

Description of the Current System

The IDP should describe the utility service territory and summarize information about the number of customers served by the utility. The IDP should also provide data about key distribution system parameters, including:

- ☐ Status of AMI deployment by customer class;
- ☐ Miles of underground and overhead wires, possibly categorized by voltage;
- ☐ Number and capacity of distribution substations;
- ☐ Number and capacity of distribution transformers;
- ☐ Monitoring and measurement capabilities on the distribution system, for example the percentage of substations and feeders for which the utility has real-time supervisory control and data acquisition (SCADA) capability;
- ☐ Historical coincident and noncoincident peak loads on the distribution system;
- ☐ Estimated or known distribution system line losses;
- ☐ Amount of DG installed on the system (number of systems and nameplate capacity in kilowatts or kW) by generator types, noting geographic locations as needed for planning purposes;
- ☐ Amount and locations of distributed storage installed on the system (number of systems and ratings, measured in kilowatts and kilowatt-hours or kW and kWh);
- ☐ Number of EVs in each region of the service territory;[3]
- ☐ Number, capacity, and locations of public and, where data are available, private EV-charging stations;
- ☐ Number, capabilities, and locations of any islandable microgrids;
- ☐ Recent history of investment in demand-side management (EE and DR) and results (energy and demand savings); and
- ☐ Recent history of distribution system investments (in dollars) categorized by reason for investment (e.g., replace failing equipment, increase capacity, etc.).

Planned Retirements and Committed Future Resource Additions

The IDP should similarly describe any known or expected future asset changes on the distribution system and state the reason for the change. This should include planned retirements of existing assets and infrastructure projects which are already underway or to which the utility has already made financial commitments. This portion of the IDP should reflect *decisions*

3 EV batteries are technically capable of discharging energy to the grid or using it to serve other on-site loads, just like other forms of distributed energy storage. Today's EVs and EV chargers are not designed to facilitate this "vehicle-to-grid" or V2G capability, but that capability may be activated in the future. If so, planners may need to identify the number, capacity, and locations of EVs with V2G capability in the same way they characterize other forms of distributed storage.

already made; it is separate from the analysis of future needs and alternatives and the selection of preferred solutions.

Load and DER Forecast

The IDP report should include a load forecast that covers every year of the planning horizon and forecasts of expected annual additions of each type of DER on the distribution system. Load forecasts can then be combined with DER forecasts to develop spatially and temporally granular net load forecasts. The report should also describe the methods, data sources and models used to develop these forecasts. Because forecasting is increasingly complex and uncertain, utilities and regulators now commonly use a range of forecast scenarios to inform planning processes. The IDP report should describe the assumptions underlying each scenario analyzed.

Hosting Capacity Analysis

The IDP report should provide a narrative description of any hosting capacity analysis (HCA) performed. An HCA is an analytical tool that can help states, utilities, developers and other stakeholders gain greater visibility into the current state of the distribution grid and its physical capacity to host DERs. The results of the HCA are typically displayed visually in the form of a map, which color-codes feeders or line segments according to their hosting capacity range, published with accompanying datasets containing the more detailed underlying data. The maps and datasets together provide public access to hosting capacity values by location along with information on specific operational limits of the grid and other important grid characteristics, including areas on the grid that might be able to accommodate additional DERs without violating hosting capacity limitations. The HCA may need to be run on the entire distribution system under different scenarios about assumed DER growth across *varying time horizons*.

Needs Assessment and Risk Analysis

The IDP report will need to summarize both the methods and the results of the needs assessment step. This is the step where the current and planned capabilities of the distribution system are assessed to see if they can adequately serve the forecasted net load. Within the needs assessment portion of the report, the utility should first explain the criteria used to assess reliability and risk and the modeling tools and methods used to identify future system needs. The IDP report should then summarize the results of the assessment, beginning with the identified needs. Finally, the IDP report should describe the criteria used to prioritize grid investments and the results of that prioritization exercise.

Evaluation of Options for Meeting Forecasted Needs

In a traditional distribution planning process, virtually every need would be satisfied by finding the least costly, utility-owned transmission or distribution infrastructure investment that solved each problem. In an IDP process, those traditional options are supplemented with equal consideration of non-wires alternatives (NWAs), including targeted applications of energy storage, DG, DR, managed EV charging, microgrids and EE. Changes in rate design that affect peak demand should also be considered.

The IDP report should describe the assumed capabilities and costs of each option category considered. Because the adoption of customer-owned or third-party-owned DERs is not unlimited and not controlled by utilities, planners may need to assess the amount of DERs that might reasonably be deployed in time to meet identified needs assuming utilities apply their best efforts to encourage and incentivize such adoption. EE potential studies, for example, could be used to estimate how much EE could be procured in a targeted area over a given timeframe. Ultimately, the IDP report should identify the preferred solution and compare the expected cost of that solution to the expected cost of other options that were deemed technically capable of meeting the need. If risk or other criteria factor into the selection of the preferred solution, those criteria should also be included in the comparison. And finally, if the IDP process used a range of assumed values or assessed multiple scenarios, the least costly option might vary from one scenario to the next or vary depending on which assumptions are used. In such cases, the report should explain how the preferred solutions were selected.

Action Plan

An IDP should include an action plan, which is the culmination of the process in which numerous scenarios are considered to develop the best options for meeting forecasted needs. The purpose of an action plan is to set forth the actions that need to be implemented in the near term, as in the first four or five years of the planning period. The action plan should include the plans for soliciting the deployment of DERs, as well as plans for permitting, constructing, preparing required reports and other significant activities where replacement, upgrades or expansion of utility infrastructure has been identified as the best option. Plans for the retirement or retrofit of existing major equipment should also be identified. The action plan should include a timeline that establishes the sequence of events for each action to be taken.

Summary of Stakeholder Engagement

Finally, the IDP report should explain the roles that stakeholders played in developing the plan. This should include at a minimum identifying the involved persons and their organizational affiliations, summarizing any stakeholder meetings that were convened and noting any opportunities for comment that were afforded outside stakeholder meetings.

Challenges for Developing and Implementing an IDP

The process of developing an IDP raises new challenges for everyone involved. In this section, we examine some of the key challenges for utility commissions, utilities, customers and DER providers.

Commissions

Commissions may need to consider different approaches than their traditional regulations and practices. Most have not had experience with granular and detailed planning processes for grid investments at the distribution level. Historical tariffs, rules and practices will need to change to align costs with prices. It is imperative that a commission understands the goals it is trying to achieve and how it wants to try to achieve them and works to reduce the challenges and barriers that might impede its progress toward those goals.

Some of the biggest challenges for Commissions will relate to staffing, retail rate design and DER compensation, state rules that may prohibit or inhibit DER deployment, and data transparency and ownership. Commissions can begin by making sure they have the right staff capacity and expertise to oversee the IPD planning process and utility implementation of the IDP. If necessary, gaps in capacity or technical expertise could be filled by contracting with qualified impartial experts.

Next, the challenge of developing a good IDP is closely tied to the challenge of optimizing DER deployment. If DERs are deployed in the right amounts and the right places, they can contribute to the most reliable, least-cost distribution system. If investment in DERs is too high (e.g., because they receive compensation in excess of their value to the grid) or too low (e.g., because they are not used to defer more costly system upgrades), system costs will increase. Customer decisions concerning DER deployment are heavily influenced by decisions that utility commissions make about retail rate design and DER compensation. To get the right mix of resources installed on the grid, Commissions may need to reconsider their current approach to retail rate design and DER compensation. This would most likely occur outside of an IDP proceeding in a general rate case or a separate rate design proceeding. Given the complexity of this topic, additional guidance is presented in Appendix 2.

Commissions can examine the regulatory environment in which DERs will be deployed to make sure that current rules do not unduly hamper DER growth at sub-optimal levels. For instance, the existing statutory authority, or existing commission rules, may prohibit third-party aggregation of demand response resources or third-party ownership of rooftop solar systems. Interconnection rules are another example of an area in which customers may face long delays, confusing requirements, or high costs and fees. Commissions can strive to ensure their regulations address modern technology, while also staying flexible enough for future changes and third-party business models. Technology-specific rules, such as requirements for smart inverters or interoperability standards, can help steer resources in directions that can provide more benefits and options for the customers and the grid.

It is crucial that the privacy of customer-specific data be protected with modern cyber security best practices. Commissions generally want to ensure utilities know what is expected of them, are following the latest best practices, and allow for adequate recovery of any associated costs. As commissions and utilities struggle to address this complicated topic, it is important to ensure that customers have adequate privacy protections. It is equally important to determine what types of data customers should be able to easily access and to mitigate any possible risks in providing that data to them. This includes a safe way to share customer-identifying data with third parties that wish to market and price potential services to those customers. In any event, no customer-specific information should be shared without the customer's explicit consent.

Utilities

Maintaining safe and reliable grid operations now requires more data than ever before. One major challenge for utilities is the need for improved visibility of behind-the-meter resources – i.e., sufficiently accurate data about the locations, capabilities and status of DERs to enable sound planning and system operations. A lack of visibility can lead to bad infrastructure investment decisions, inefficient system operations and reliability problems.

Under traditional cost-of-service regulation, utilities have an inherent incentive to maximize throughput, that is, kW and kWh sales. The throughput incentive can be a challenge for utilities implementing IDP because deployment of DERs can reduce energy deliveries or peak customer demand, resulting in lost revenues and decreased profits. Fortunately, practical solutions for addressing the throughput incentive exist. One option is to use smart rate designs and fair DER compensation mechanisms, as detailed in Appendix 2. Rate designs and compensation mechanisms that send appropriate price signals to customers about system costs and cost drivers should minimize lost revenue problems. Another common approach to addressing the throughput incentive involves revenue regulation, also known as revenue decoupling.

Under traditional cost-of-service regulation, utilities create shareholder value by adding capital assets to their rate base and earning a rate of return on the residual value of these assets as they depreciate. In contrast, operating expenses are usually treated as a pass-through expense and do not contribute to utility earnings. This creates a utility investment preference for capital expenditures rather than operating expenditures when seeking solutions to address grid needs — a "capital bias." Ideally the decision to meet system needs through asset-based solutions or service-based solutions will be decided based on which solution set provides the best value to customers, rather than which solution set has more favorable regulatory treatment for shareholders. Regulators are investigating opportunities to level the playing field between capital expenses and operating expenses for the provision of grid services. One option is to allow utilities to earn a rate of return on total expenditures. Performance based regulation (PBR) offers another option for addressing capital bias and aligning utility shareholder interests with least-cost IDP solutions. The most common approach to PBR worldwide is the multiyear rate plan, which enables utilities to operate for several years without a general rate case. More expansive forms of PBR can partially or fully replace rate base as the driver of utility shareholder profits. A commission can use these and other similar tools to address the capital bias and greatly improve the IDPs produced by utilities and the value they provide to the public interest. By better aligning utility shareholder interests with those of customers, commissions are then free to optimize DER deployment and compensation through rate design or other DER compensation methodologies.

The risk of stranding existing utility assets could be a challenge in developing and implementing a comprehensive IDP. This is because an IDP could reveal opportunities for distributed solutions that are cost effective for customers but that reduce the usefulness of, or demand placed on, existing assets. In other words, when developing an IDP, utilities might be concerned with whether their existing assets will be replaced before they are fully depreciated. This is less of an issue in restructured states where distribution utilities do not own generation assets. Thus, utilities should consider the rapid pace of technological advancement and the possibility of creating a future stranded asset before making any kind of major infrastructure investment. One important strategy to reduce the risk of future stranded assets is for utilities to deploy technologies that utilize open technical standards.

Many utilities believe they are best suited to provide cost-effective DER solutions and see this as a natural expansion of their traditional role. Nonutility DER providers argue that these products and services belong in a competitive market. The decision about what types of DERs, if any, utilities can own or control has implications for the development and implementation of a comprehensive utility IDP. If the least-cost solutions involve some combination of non-utility-owned assets, such as customer or third-party-owned solar and storage, utilities may want to control or set boundaries on how those assets are operated and how the owners will be compensated for services rendered. At a minimum, if the utilities cannot control the DERs, they will need some assurance that they will at least have visibility into the operation of those assets and that they will be operated in ways that meet identified distribution system needs. Without this, utilities will be likely to prefer a utility-owned solution, which could be costlier in some cases.

Customers

The most fundamental challenge for customer adoption of DERs is obtaining compensation that is adequate to justify the investment. Customers will install DERs if the DERs provide value through bill savings or other revenue streams that exceed installation and operational costs. Currently, it can be very difficult for customers to determine the total value proposition that DERs will provide. In addition, most decisions regarding compensation are made by other parties. Some of the key challenges regarding customer compensation that are determined by utilities or regulators are addressed in Appendix 2.

Customers who are interested in owning or hosting DERs also face their own unique set of challenges, relating to education, equity, access to financial products, physical limitations, and other issues.

DER Providers

The companies that offer DER products and services to utility customers must navigate between the realms of utility regulations, tariffs, and procedures on the one hand and wholesale electricity market rules on the other. This leads to a unique set of challenges for DER providers.

While individual DERs may be quite small (e.g., only a few kW), aggregated DER resources can add up to hundreds of MWs and can become significant players in distribution and wholesale markets. As noted in Appendix 2, market revenues can be a key component of DER compensation. DER providers can play a key role in helping customers to access market revenues, but they face significant challenges. Their ability to overcome those challenges will influence whether DERs are deployed in an optimal fashion and whether a true least-cost IDP can be achieved in practice.

The proliferation of DERs in the electric value chain has increased the interaction that utilities have with third-party entities, particularly those that use DERs to provide services in addition to traditional demand response services. Smart inverters with inherent smarter functions are being deployed with capabilities that can benefit not only the DER customer being serviced, but also the utility grid in the respective area. But taking advantage of these new capabilities presents new challenges for DER providers and utilities and calls for reforming the interaction between them to achieve greater coordination of resource operations.

Other Considerations for Planners and Regulators

There are several policy and technical issues that will significantly influence the assumptions, data and analysis of modeling results for an IDP, which commissions will need to be aware of as they guide and oversee the IDP process.

To begin with, policymakers and regulators are enacting policies that are shaping the growth of DERs and net load in important ways. An understanding of how these policies affect DER adoption is important for IDPs, especially at the DER forecasting stage.

The transition to a power system involving two-way flows of electricity and information (data) will also require a constant reappraisal and updating of technologies and applications. New power grid technologies and applications are emerging and will continue to emerge, including advanced power grid components, advanced control methods, new sensing and measurement capabilities, integrated high-speed communications, and interfaces and decision support tools. Power grid technologies and applications can be categorized into the major areas they impact. Consumer-enabling technologies installed behind the meter empower customers by giving them the information, tools and education they need to effectively utilize the new options provided to them by the evolving grid. Advanced distribution technologies (installed between substations and customers' meters) improve reliability and enable "self-healing" while supporting two-way power flow and DER operation. Advanced distribution operation technologies (installed between the transmission system and substations) integrate the distribution system and customer technologies and applications with substations and RTO applications to improve overall grid reliability and operations while reducing transmission congestion and losses. A cost-benefit analysis can identify leading technologies in a viable solution portfolio that can improve the reliability of the grid, lower costs to consumers and yield system, consumer and societal benefits.

The term "transactive energy" is being used by some to capture the ongoing evolution from a centralized generation, transmission and distribution system to a complex two-way power-flow-enabled system that allows energy transactions at all levels of the value chain. A multitude of stakeholders and their resources including smart homes, smart buildings and industrial sites engage in automated market trade with other resources at the distribution system level and with aggregation or representation in the bulk power system. Communications are based on prices and energy quantities through a two-way market-based negotiation. A number of technologies and process improvements will be needed before transactive energy exchanges become commonplace, but establishing the communications network is arguably the first and most important step toward realizing value creation by expanding transactions. Transactive energy systems can use existing messaging protocols for direct or indirect control of DERs, various management functions, reporting, metering and transactive functions. Technical standardization can be accelerated by extending existing protocols. Access to electronic energy usage data allows customers to track and manage their energy consumption and thus is a prerequisite to enabling customer engagement in transactive systems. Availability of usage data also empowers nontraditional stakeholders to support the transition to a modern grid. The current inability of many utility customers to access their data or authorize the use of their data inhibits the energy marketplace. Transactive energy systems by design will include a platform where all customer and service providers have access to data. The platforms need to be user-friendly and simple for consumers.

Conclusions and Recommendations

The emergence of DERs as practical, affordable power system resources is changing the nature of the distribution grid and the roles of utilities and regulators. Power system planning, including distribution planning, must adapt to this new reality to maintain reliability and minimize costs.

A key aspect of the necessary adaptation is to inject transparency and oversight into an activity that has traditionally been left to utilities to manage on their own. Furthermore, this newly transparent process must take into consideration how DERs change load profiles and how their deployment and operation can be coordinated with the development and operation of traditional utility infrastructure. In short, IDP will become a necessary part of maintaining reliability and minimizing costs.

This paper provides detailed guidance to public utility commissions on the opportunity and the challenges associated with instituting an IDP requirement for regulated utilities. It concludes with a few of the most important recommendations found herein:

- Commissions, if they have the authority to do so, should investigate IDP and eventually institute an IDP requirement for the electric utilities they regulate;
- Because the IDP process may affect and be affected by other regulatory proceedings (e.g., grid modernization initiatives, resource and transmission planning), Commissions should consider how to coordinate such efforts to minimize counter-productive policies, confusion, and workload for themselves, the utilities, and all stakeholders;
- Commissions should ensure that stakeholders have a distinct and prominent role in any IDP process, not only in reviewing draft plans but also in the early stages of plan development, given that the actions of customers and DER providers will ultimately determine the rate and locations of DER deployment;
- When seeking solutions to identified grid needs, an IDP should give full, fair, and equal consideration to all traditional infrastructure options as well as all cost-effective DERs, including combinations of geographically-targeted DERs that constitute NWAs;
- In states that have adopted public policies favoring DERs or specifically promoting their deployment, the evaluation of solutions to grid needs should reflect those preferences and the plan should address the need to accommodate customer deployment of DERs;
- Hosting capacity analysis and hosting capacity maps should be included in an IDP, and are a crucial outcome of the planning process that can be used to steer DER deployment to where it is most valuable and expedite interconnection requests;
- Commissions, the utility planners they regulate, and other stakeholders should expect IDP to be challenging, at least initially, as it is a relatively new practice, but understand that methods and tools will improve over time, best practices will be identified and

improved, and local experience and knowledge will grow with each iteration of the planning process;

- Some of the key challenges that will need to be addressed by all parties to optimize IDP outcomes include:
  - Developing staff expertise and capacity for IDP and IDP oversight;
  - Designing retail rates and compensation mechanisms to send appropriate price signals and provide fair compensation for the system value of DERs;
  - Making the locations, capabilities, and operational status of DERs more visible to utility planners and transmission system operators;
  - Adapting cost of service regulation and utility business models to make utilities indifferent to or supportive of cost-effective DER deployments;
  - Educating customers about DER options and ensuring that low-income customers have reasonable opportunities to share in the benefits; and
  - Enabling aggregations of DERs to provide bulk power system and distribution system services and receive compensation for those services.

I. INTRODUCTION: PURPOSE AND SCOPE OF THIS GUIDANCE

The modern electric power system is undergoing a sea change that is transforming the generation, distribution and consumption of electricity. Technological advances, falling prices, changing business models, regulatory reform, the drive to develop a more resilient grid and evolving attitudes toward the natural environment are the underlying causes of this transformation. In particular, the integration of distributed energy resources (DERs)[4] into the electric power system by utilities, independent power producers and energy consumers is profoundly changing how we plan, build and operate the system. These new resources pose a challenge and an opportunity for distribution utilities, transmission system operators, retail energy suppliers, and regulators.

This manual is designed to assist utility commissions in the restructured jurisdictions that participate in the Mid-Atlantic Distributed Resources Initiative (MADRI)[5] with guiding and overseeing the development of integrated distribution plans (IDPs) for electric utilities.[6] Commissions in other states may also find it useful.

Prior to restructuring, the distribution portion of a vertically integrated electric utility's system typically received less regulatory scrutiny than the generation and transmission portions. This made sense because transmission and generation investments often had more significant rate impacts than distribution investments and there were few DERs seeking to integrate with the utility system.

In restructured jurisdictions, commissions generally have limited authority over generation and transmission but retain full jurisdiction over distribution services and rates. This naturally leads those commissions to focus on the distribution system. Furthermore, in today's world, the distribution system has become the center of attention due to more severe and more numerous storm events, aging infrastructure, and the need to interconnect ever-increasing numbers of DERs to the grid. Add to this the introduction of new technologies, which change the nature of how the distribution grid functions and operates. Regulators, utilities, DER providers, consumers and other stakeholders are now facing a number of new challenges relating to the distribution grid, including:

- The need to replace aging infrastructure;
- Coping with decreasing overall loads and utility revenues in many jurisdictions;
- Achieving environmental and climate policy goals;

[4] The term DER is broadly used but may be defined differently in the statutes, regulations or policies of each jurisdiction. The term virtually always encompasses behind-the-meter distributed generation and electricity storage. In some jurisdictions, it may also include some combination of demand response, energy efficiency, electric vehicles and in-front-of-the-meter generation or storage resources that are interconnected at distribution voltages. Microgrids, which typically rely on a combination of DERs, are sometimes considered to be DERs unto themselves. This guidance manual generally includes all these types of resources in its definition of DERs, with the understanding that definitions in some jurisdictions may be narrower.

[5] The participating jurisdictions are the District of Columbia (DC), Delaware (DE), Illinois (IL), Maryland (MD), New Jersey (NJ), Ohio (OH) and Pennsylvania (PA).

[6] Throughout this document and in much of the literature, the acronym IDP is used interchangeably to refer to either the planning process or the resultant plan. The specific meaning should be clear from the context of each usage.

- A greater emphasis on resilience given the increased impacts of outages on customers and communities and higher number of extreme weather events, including wildfires;
- A need for improved reliability at the distribution system level;
- Incorporation of new utility scale technology, such as advanced metering infrastructure (AMI), distribution automation and moving from a radial distribution system to a mesh distribution system;
- Increasing DERs, such as customer-owned solar photovoltaic (PV) generation, energy efficiency (EE), demand response (DR), including whole house or building automation and managed EV charging, and storage, both electric and thermal;
- Embedded interclass and intraclass subsidy and equity issues;
- Increased stakeholder interest in and importance of distribution planning and utility distribution investments; and
- Accommodating two-way flows of energy (and information) on distribution systems that were originally designed for single-direction flows.

This is a formidable list of challenges, especially given the need to create a distribution system that works for all stakeholders, including the utility. Even so, most commissions have until recently given little or no scrutiny to the details of distribution system *planning*. Utility investments are reviewed for prudence, after the fact, but in most cases the planning process has remained within the exclusive purview of the utilities, with little or no transparency, public involvement, or regulatory oversight. This hands-off approach to distribution system planning might not be sustainable, as the cost and reliability impacts of DERs could quickly grow to the point where they overshadow the impacts of many other regulatory decisions which routinely attract great scrutiny from commissions.

IDP is a process that systematically develops plans for the future of a distribution grid using inputs supplied by the electric utility, the commission and interested stakeholders. The planning process is “integrated” in the sense that all possible solutions to distribution system needs are considered. A good plan will:

- Describe the existing distribution system;
- Identify planned retirements and committed future replacements or additions to existing distribution system assets;
- Assess the potential of the existing system to host additional deployments of DERs without negatively impacting reliability or power quality;
- Forecast loads and DER deployments for each year of a long-term planning horizon;
- Assess and prioritize the need for system upgrades or operational changes to accommodate future loads and DER installations;
- Evaluate and compare options for meeting the forecasted needs to find preferred solutions; and
- Detail an action plan for addressing those needs that require near-term attention.

Ultimately, the objective of the final plan is a distribution system that operates for the public good, meeting the objectives set out by stakeholders in a cost-effective manner. Over the long term, the IDP process should reduce costs, improve efficiency and point the way toward a more sustainable distribution grid — one that is safe, secure, reliable and resilient.

An IDP can also foster beneficial change within the distribution grid in response to new technologies or customer expectations. The IDP process can:

- Evaluate potential new investments in distribution infrastructure (wires) or non-wires alternatives (NWAs);
- Encourage optimal deployment, integration and operation of DERs;
- Explore the potential for peer-to-peer transactions within the grid; and
- Serve as a venue for considering new or different roles for the utility and other parties in coordinating DER activity on transforming the distribution grid.

Finally, a good IDP process can also give the commission early insight and more control over decisions about conflicting policies. For example, if electric vehicle (EV) ownership is clustered geographically, it may be sufficient and relatively inexpensive to upgrade local transformers on an as-needed basis. However, if widespread EV adoption occurs, it would likely be cheaper to invest in controlled charging, EE and DR than to upgrade the transformers on an entire system. An IDP process can give the commission visibility into the utility's planning decisions and allow the commission to exercise influence, set policy and develop regulations before spending decisions are made.

The Electric Power Research Institute (EPRI) has long been a leader in research on distribution system planning techniques. EPRI offers extensive technical assistance to its funding members on how to do modern distribution planning, and those members are well advised to make use of EPRI's expertise. However, some of EPRI's most helpful resources are not freely available to the public.[7] Public utility commissions in the MADRI jurisdictions, as well as most of the parties that appear before them, have expressed the need for guidance on distribution system planning techniques that is free and publicly available. This document seeks to fulfill that need. The manual is designed to help commissions in the MADRI jurisdictions consider electric utility distribution planning in an organized and systematic manner that leads to a cost-effective distribution grid that meets to the greatest extent practicable the needs of all stakeholders. A single manual for all the MADRI jurisdictions will also foster a unified approach across the numerous different subsidiaries of the large electric utility holding companies that dominate the MADRI footprint.

The balance of this manual addresses:

- Options and issues for establishing and overseeing a formal IDP process for electric utilities through regulatory action;
- Steps in the process of developing an IDP;
- Content of an IDP filing;
- Challenges for developing and implementing an IDP and potential solutions; and
- Technical considerations for planners.

[7] See, most importantly: EPRI (2018, April 5). *Distribution planning guidebook for the modern grid*. Palo Alto, CA: Electric Power Research Institute. Retrieved from: https://www.epri.com/#/pages/product/3002011007/?lang=en-US. This guidebook is free to EPRI's funding members but costs $15,000 to all others. Without in any way diminishing the value of EPRI's work, it is a simple fact that some commissions and most of the interveners that appear before them are not funding members of EPRI and will not invest in such an expensive reference document.

II. ESTABLISHING A FORMAL IDP REQUIREMENT THROUGH REGULATORY ACTION

The economic rationale for commission oversight and regulation of the distribution grid lies in the desire to replicate competitive outcomes in industries that are "natural" monopolies. Distribution service has historically been viewed as a monopoly service because it would be redundant and costly for more than one entity to string wires across the same service territory. However, as the nature of the distribution grid is changing to allow for more open access and two-way flows of power, new entities are beginning to offer similar services through different mechanisms. While the utility's essential natural monopoly characteristics are still present and provide the rationale for state commission regulation, the characteristics of that regulation may need to change to accommodate DERs and the advantages they provide.

Commissions that wish to establish a formal IDP requirement will need to consider their statutory authority to administer such a requirement and the type of regulatory proceeding that will best serve their purposes. They will also need to make key decisions on a variety of procedural questions about the scope of the planning requirement, stakeholder participation, and other issues. And finally, the Commission will want to consider whether and how to coordinate its work on IDP with other planning processes and regulatory proceedings. These topics are discussed in more detail below.

A. Commission Authority

At the root of all actions taken by the commission is the question of whether it has the statutory authority to undertake a rulemaking, investigation or proceeding that breaks new ground. Most states provide their commissions with general supervisory authority over all business aspects of regulated utilities as they relate to costs and quality of service. In this regard, a clear argument can be made that supervision over distribution planning is a vital component of this authority. Fundamentally, IDP is designed to ensure that investments in the utility distribution system ensure reliability, are built to be resilient, and employ least-cost options. But utilities must also enable the safe interconnection of DERs by customers and third parties and strive to optimize the use of new resources and grid technologies while reasonably balancing the risks and opportunities.

Some commissions may take a narrower view of their authority to oversee and guide distribution planning and may want more specific statutory language referencing IDP. In this case, passing legislation authorizing commission involvement in and oversight of integrated distribution system planning would be necessary. Any necessary IDP legislation should be simple and germane to the commission's authority to expedite its passage. However, as stated above, while IDP is a new concept in utility regulation, it is nevertheless at the core of what commissions were established to oversee, especially with respect to the convergence of an aging grid infrastructure, new technologies and options such as DERs and the occurrence of more severe climate events.

B. Type of Commission Proceeding

The commission has several options for considering whether and how to develop IDPs: an issue-based investigation or workshop, a rulemaking, a utility-specific contested case, or some combination of these proceedings. Each procedural option is discussed below

Some jurisdictions may opt for a more informal workshop or investigation to introduce the subject to stakeholders and receive input. This can be a productive process by bringing in industry experts and commission staff from jurisdictions that have already engaged in creating an IDP. It is a way to learn about best practices and the pitfalls to be avoided and may be less costly (in terms of the time and human resources required) than a more formal proceeding. Providing stakeholders with the opportunity to comment can provide the commission with useful information specific to its jurisdiction. In addition, the signaling of activity by the commission in this direction might result in DER providers focusing attention on that jurisdiction as an area of interest for business development. Thus, a workshop or investigation can be a good gateway to a thoughtful, inclusive process leading to the development of an IDP. One potential drawback is if "the perfect becomes the enemy of the good" – i.e., if a process seeking consensus among all stakeholders becomes so lengthy that it slows progress toward the development and implementation of an actual (albeit imperfect) plan. Utility operations will not cease during plan development, and the utility may make investments in its distribution system that are not least cost or that would not have been a preferred solution had an IDP proceeding taken place.

An IDP can be viewed as analogous to a more formal integrated resource plan (IRP),[8] which includes a rigorous review process that is preceded by a utility filing containing detailed information as required by the commission. Even with a more formal process, there are a range of options. Some jurisdictions have promulgated regulations for IRPs, while others have opted for guidelines.[9] Regulations are binding requirements that must be followed unless a waiver is sought and approved by the commission. Guidelines are advisory and not enforceable in the same manner but indicate the commission's desire as to what it would like the utility to file. Both regulations and guidelines are improved if they are subject to a public comment period that can provide additional information and perspectives that the commission may not have considered in the initial drafting. For the most controversial and difficult issues, a commission could consider issuing questions for comment prior to releasing a draft of the proposed regulations for public comment.

Developing some form of consistent framework for the filing of an IDP that must be followed within each jurisdiction is important for several reasons. It ensures that the commission and stakeholders or intervenors receive the initial level of detail required to review a utility plan. It also requires a careful and thorough process by the utility to develop a plan. Furthermore, it

8 As with the IDP acronym, IRP is used interchangeably to refer to either the resource planning process or the resultant plan. Again, the specific meaning should be clear from the context of each usage.

9 Citations to IRP statutes and rules for all states that had IRP requirements as of 2013 are available in: Wilson, R., and Biewald, B. (2013). *Best practices in electric utility integrated resource planning*. Synapse Energy Economics for the Regulatory Assistance Project. Montpelier, VT: RAP. Retrieved from https://www.raponline.org/knowledge-center/best-practices-in-electric-utility-integrated-resource-planning/. Refer to the appendix in that document. Some states may have updated their statutes or rules since that report was published.

creates uniformity in utility filings, making it easier for commission staff and the public to review them.

Regulations on an IDP process can include both the process and the substance of the filing. As to process, continuing the analogy of IRPs, some commission regulations commence the process with the filing of the full IRP, while others require one or more technical conferences as the utility is developing the IRP to ensure that the utility is on the right track with its methodology for developing the plan and the scenarios and information it is considering.[10] The benefit of a technical conference or series of stakeholder workshops is that it can serve as an early course correction before too many utility and stakeholder resources are deployed pursuing a defective direction in the preparation of the plan.

An IDP case filing allows the commission to review and investigate the plans of each utility under its jurisdiction to upgrade its distribution system. Having regulations in place prior to the filing provides a road map to ensure each utility initially provides all information that is necessary for the commission to begin its review and ultimately render a determination as to the reasonableness of the plan prior to any expenditures taking place. A utility-filed IDP would commonly be a litigated process in which there is intervenor participation and the commission sets forth findings of fact and conclusions of law that it applies to its decision. This type of proceeding can be quite expensive and time consuming for participants and for the commission, compared to less formal options. But as discussed below, the presentation of expert evidence can be a great resource for the commission in its deliberations. The outcome of an IDP proceeding should be the development of a plan of action by the utility to guide its future actions to maintain and upgrade its distribution system. Those actions could potentially include competitive procurement of DERs or new tariff-based compensation mechanisms.

C. Key Commission Decisions Regarding an IDP Proceeding

At the outset of any IDP proceeding, the commission will need to make several key decisions that shape the level of effort and roles of all parties and how the completed IDP will be used. These key decisions are summarized below.

1. Scope of IDP: Utility versus Jurisdiction-Wide Planning

When it comes to evidentiary proceedings, as opposed to rulemakings or issue-based workshops, commissions typically will proceed one utility and one case at a time. These cases are seldom simple, are highly fact-dependent and require the dedication of staff and stakeholder resources. Taking each case one at time may allow for a deeper dive into issues and consideration of attributes specific to each utility such as geography of the service territory or characteristics of the customer base. The benefit of a single proceeding is the ability to ensure that the outcomes are focused on the single utility and what is in the best interests of its ratepayers. However, cases involving distribution planning could take a different course of action, especially where large

[10] For example, PacifiCorp (which owns utilities operating in six Western states) hosted seven public meetings with stakeholders on various IRP topics before filing its last IRP in April 2017. Refer to the company's IRP public input web page at http://www.pacificorp.com/es/irp/pip.html for details.

mergers have created "sister" utilities within one jurisdiction, such as in Maryland and Pennsylvania.

A joint proceeding involving multiple utilities could produce a more consistent statewide approach to planning. It also avoids the concern that the first utility proceeding could set a precedent for all utilities to follow. Even though the participants and the facts of each case may be different, it is reasonable to expect that utilities will seek to replicate what they perceive as favorable aspects of earlier decisions while seeking to alter aspects they view as unfavorable.[11]

A regional approach may be difficult, even though one holding company may have affiliates in multiple MADRI states, because the laws and operating characteristics are different in each state. Moreover, state commission jurisdictions are bound by their own jurisdictions and cannot rule on matters before another jurisdiction.

2. Scope of IDP: DERs to Consider

To be used as an effective tool, an IDP needs to be comprehensive in terms of examining the entire grid and all the potential options for improving the grid from a reliability, resilience and cost effectiveness standpoint. A good planning process will also take into account and seek to fulfill other public policy goals of the jurisdiction in question (e.g., state environmental or climate goals). This means having the utility provide information that identifies areas on its grid that are currently, or soon will be, constrained or areas where the utility equipment is in disrepair, outdated or inefficient. An IDP proceeding would also require a full review and consideration of options to restore or upgrade the grid, including traditional solutions like replacing equipment, or deploying new technologies, DERs (including demand-side resources) or other NWAs. DERs reside with increased frequency on the customer side of the meter and can be deployed to provide support to the grid when it is cost effective to do so.

As part of an assessment of its grid, a utility should provide forecasted data showing the growth in DERs and their projected effect on the need for utility investments. DERs can serve as alternatives to grid reinforcement but can also impose additional needs on the distribution network by causing potential power quality problems or equipment overloading. Moreover, an IDP should include a competitive bidding process that includes DERs implemented in ways that meet the needs of the grid so that the best options (considering least-cost and least-risk objectives) are selected.

[11] Note that commissions are generally not bound by previous orders and are free to make decisions based on changes in policy and the facts in a particular proceeding. Generally, a commission's decisions are entitled to great deference, as being the judgment of a tribunal appointed by law and informed by experience. See, for example, *Iowa–Illinois Gas & Electric Co. v. Illinois Commerce Comm'n* (1960), 19 Ill.2d 436, 442, 167 N.E.2d 414. However, where a commission's decisions drastically depart from past practices, it is entitled to less deference. See, for example, *Business & Professional People for the Public Interest v. Illinois Commerce Comm'n* (1989), 136 Ill.2d 192, 228, 144 Ill.Dec. 334, 555 N.E.2d 693 and *Citizens Util. Bd. v. Illinois Commerce Comm'n*, 166 Ill.2d 111, 131–32 (Ill. 1995).

3. Planning Horizon, Timing of Filings and Update Frequency

It is axiomatic that the longer the forecast period, the less accurate it will be. It is much easier to project the probable scenarios in a two- to three-year range than projecting 20 years from now. Given the fast-paced evolution of technology and its adoption, this becomes increasingly the case as we do not know what technologies will be available even three years from now. Obsolescence of expensive technologies is a concern. Nevertheless, there is value in projecting far out into the future to create a tableau of what could possibly be anticipated. Accurate projections are especially important when investments are made that have long depreciable lives (e.g., 20 to 40 years).

Nearly all of the many examples of integrated *resource* planning in U.S. jurisdictions have examined a 10- to 20-year planning horizon, with the plan updated every two to five years.[12] A long planning horizon allows utilities to identify needs well before they become urgent and with enough lead time to allow for consideration of solutions that may require multiple years of planning, permitting and construction. The frequent updates ensure that planning assumptions are consistent with current information and recent changes to policies and regulations.

Commissions are likely to apply similar logic regarding the planning horizon and update frequency for integrated *distribution* plans. The time horizon, however, tends to be shorter for IDP than for IRP in the few examples of publicly available IDPs. Based on practices observed to date, an IDP should probably cover a five- to 10-year planning horizon, at a minimum, though there are examples that reach out as far as 30 years.

The timing of initial IDP filings and the frequency of IDP updates are matters of commission discretion. Where a state has multiple utilities subject to IDP filing requirements, the commission may choose to stagger the timing of each utility's initial planning process to avoid creating a strain on commission staff and stakeholder resources and to maintain their ability to review and analyze the filing. Given the rapid pace of change in DERs, smart-grid technologies and state energy policies, a commission might want to consider requiring relatively frequent updates to each utility's IDP — perhaps even annual updates. However, preparing, reviewing and evaluating an IDP is a considerable undertaking, therefore some commissions will find that two or three years between filings is appropriate. Moreover, commissions will want to reserve the right to order a complete or modified IDP in between the scheduled updates as may be warranted due to catastrophic events or significantly changed circumstances. Commissions will also want to consider whether to align the timing and frequency of IDP filings with related efforts, such as IRP filings, energy assurance plans, energy master plans, etc.

4. Stakeholder Participation

Commissions across the nation, including those within the MADRI footprint, rely on stakeholder input to create a robust public record that includes diverse ideas and perspectives from which to render a decision. Moreover, having stakeholder participation increases transparency and creates more confidence in the commission's processes and decisions.

[12] Wilson and Biewald, 2013.

The Commission may find that the list of stakeholders interested in an IDP proceeding is broader than for most other regulatory proceedings. In addition to utilities, residential consumer advocates, and industrial customer groups, an IDP proceeding may attract DER service providers and market participants of all types, environmental organizations and environmental regulators from other state and local agencies, and transportation interest groups and agencies (because of the role of EVs in planning). The state energy office may also wish to participate.

The right to be heard is a fundamental principle of good governance. Stakeholder participation in every facet of IDP provides balance — as opposed to only having the utility perspective. To the extent that stakeholders can bring forth expert opinions or testimony or advocate for specific policies, they will add to the richness of the record so that the commission can reach the best decision possible. At a minimum, stakeholders should have the opportunity to review and comment on a filed IDP. In addition, commissions may find it reasonable and in the public interest to order utilities to engage expert stakeholders collaboratively, early in the process, before anything is filed with the commission. This could include collaboration with experts from other state and local government agencies on environmental or transportation-related issues. Some commissions might even wish to appoint an independent subject matter expert to *lead* the stakeholder engagement activities.[13]

5. Binding or Nonbinding Effect of a Completed IDP

One question that frequently arises in IRP policy discussions is whether a utility filing should be informational or subject to a commission approval that binds the utility to the planned course of action. Some states have chosen only to require informational filings; in such cases, the commission "acknowledges" that an IRP was submitted in conformance with established legal requirements but does not formally review or approve the content of the plan. Other states have opted for more oversight, giving the commission a role in reviewing and approving the content of the IRP. However, in these latter cases, no state has adopted a policy whereby commission approval of a utility IRP is tantamount to a decision that the investments in the plan are deemed prudent.

An informational filing approach could result in a commission review, which either finds that the filing is complete or issues instructions to the utility to correct any deficiencies. Having a plan that is not subject to future action provides the commission with more latitude when a utility files for approval of a distribution capital investment. However, the informational approach raises two concerns. First and fundamentally, the utility may not be required to file for approval in advance of its actual spending. While a utility would be wise to file for recovery of a large investment in advance of the expenditure if it is something like installing smart meters in every home, this might not necessarily be required. In all likelihood the utility would not file for approval with respect to distribution system upgrades that it views as routine. A more rigorous IDP review process resulting in an approved IDP plan may result in a different course of action, like a competitive bid for DERs rather than a system upgrade. Second, an approved IDP places the

[13] The National Association of Regulatory Utility Commissioners (NARUC) recently convened a series of conference calls for members to explore stakeholder process options. The options discussed include staff-led workshops, stakeholder engagements led by independent experts, and the limited use of independent experts for specific technical subjects.

commission in the best position to make decisions regarding the acquisition of distribution resources. In reviewing and approving a full plan, the commission has all the information and options presented for consideration. Under the informational filing approach, even when a utility files for approval, a decision on a project viewed in isolation will likely not yield the same thorough analysis and review as considering that same project in the totality of the system and the available options.

When considering the approval approach, commissions often worry that if a plan is approved as to its content, that plan will be in effect until the next IRP is filed and approved. The concern is that as the IRP ages it could lead to utility actions that no longer reflect the best options available to the utility at the time of each implementation decision. So, instead of deeming the investments in the IRP prudent, commission approval merely indicates to the utility that the planned course of action is reasonable at the time the plan is approved and based on the assumptions used to develop the plan. The effect is that the utility knows it is taking a risk if it invests in a resource that was not in its approved plan, and it has more confidence when it makes an investment that was in the plan. But either way, the investment will be subject to a prudence review using standard procedures outside of the IRP process.

Similar concerns are likely to emerge in IDP discussions and proceedings, and commissions will have similar options that fall short of preapproving the prudence of investments included in an IDP. To resolve this concern, the commission can note in an order or in its rules that approval of an IDP still requires that the utility's actions be reasonable and prudent at the time each action is taken to ensure cost recovery. Moreover, the rules or guidelines can include a process if there has been a significant lapse of time between approval of an IDP and the implementation of an aspect of the plan. For example, the commission can require the utility to file an affidavit attesting that there have been no material changes in circumstances that would warrant a change in the approved IDP with respect to the project being implemented. Alternatively, if there is a change in circumstances, the utility can file an update setting forth the changes that have occurred prior to proceeding. The commission could then decide how to proceed by either approving or denying the request or requiring comments or a hearing.

If the commission will formally approve IDPs, it may be necessary to establish approval criteria at the outset of the process. Obviously, any planning requirements that are specified in a statute, regulation, or order must be satisfied. Additional approval criteria can be expressed in general terms, allowing some latitude in their interpretation. Some examples of possible IDP approval criteria would be whether the planners used the best information currently available, whether the plan was developed with adequate stakeholder participation, and whether the planners reasonably considered alternatives such as NWAs and different types of DERs to meet different reliability, capacity, or other needs.

D. Content of a Commission Order Accepting or Approving an IDP

This section will focus on IDPs considered under a contested case hearing procedure that requires commission approval.[14] When considering an integrated distribution plan, a commission will need to issue a written order to memorialize its decision. A commission's IDP decision will likely fall into one of four distinct categories: 1. approval, 2. approval with modification, 3. denial with direction for further revisions or 4. denial without further direction.

Regardless of the ultimate decision, there are several common requirements for any commission order. As always**,** a commission order will be subject to review by the courts and should follow best practices for an administrative decision. The order should contain a recitation of the record and a review of the relevant statutes and regulations. These recitations should include a synthesis of the relevant issues and positions of the parties. These recitations summarize and analyze the administrative proceedings and are useful to aid a reviewing court.

The relevant portions of the commission's decision will be the findings of fact relevant to each issue and the conclusions of law that follow from those facts. In general, an administrative decision is granted deference on findings of fact by a reviewing court. As such, a commission decision should be careful to fully explore any relevant factual considerations and make clear findings where the evidence is open to differing interpretations. For example, a factual conclusion may be the overall hosting capacity[15] of a specific feeder based on distribution system attributes. Alternatively, in considering a cost-benefit analysis,[16] the commission can clearly quantify each cost and benefit category based on evidence and analysis in the record. A clear factual landscape is essential for appellate review and can also aid stakeholders in future administration and modification of the IDP.

Factual findings must then be applied to the relevant statute so that the commission can reach legal conclusions regarding the IDP. These legal conclusions can be jurisdictional including the commission's statutory authority to direct adoption of the plan or the legal authority to allow recovery of plan costs in subsequent rate cases. Legal conclusions might also underlie the commission's ability to weigh certain attributes of the plan, including economic benefits and environmental or climate benefits where authorized. Legal conclusions are often granted less deference on appeal and should be presented clearly and follow from a commission's statutory mandates.

[14] As noted above, this is not the only procedure to develop an IDP (Section II.B contemplates a rulemaking process, and Section II.C.1 considers a utility versus statewide scope); however, IDPs developed through alternative procedures may require a different type or form of decision from a commission. Further, some commissions may opt for a rulemaking followed by a utility filing that is subject to adjudication. This is the most prevalent process used for IRPs. In addition, the informational IDP discussed above may require nothing more than that a commission note the filing, or it may require some portions of the order contents outlined below.

[15] The term "hosting capacity" refers to the amount of DERs that can be accommodated on the distribution system at a given time and at a given location, under existing grid conditions and operations, without adversely impacting grid safety or reliability and without requiring significant infrastructure upgrades.

[16] This may be necessary at the IDP stage to approve a given plan or may be a statement of the commission's intended standard of review in a later rate case seeking recovery of IDP capital expenditures.

The result of these factual findings and legal conclusions will determine the fate of the IDP under consideration: approval (with or without modification) or denial (with or without an opportunity for revision). Where a commission approves an IDP, the order should outline any relevant next steps or opportunities for further review. This can include a timeline for implementation and processes for further stakeholder engagement and future commission review, such as later cost-recovery proceedings or plan updates. The key consideration should be an order sufficiently detailed to allow implementation without additional commission input — and one that includes sufficient flexibility for the utility to adapt the IDP to technology and market changes during the IDP implementation period.

A commission can also approve an IDP with modifications. In this situation, the modifications should be clearly delineated and include sufficient direction for stakeholder implementation. A modification may require an opportunity for party and stakeholder response and additional commission review. In this situation it is best if the commission clearly outlines the path forward and includes deadlines to the greatest extent possible.

Alternatively, a commission may deny an IDP, either with or without the opportunity for revision. The findings, analysis and conclusions of a denial are equally important as those approving an IDP for both appellate review and for the benefit of stakeholders moving forward. Denial without the opportunity for revision rejects the proposed IDP but does not preclude future filings. As such, the denial should identify the grounds for denial, such as factual inadequacy, statutory barriers or a party's failure to sustain a burden of proof. This direction will help stakeholders should they wish to offer another IDP in the future.

Denial with direction to modify the IDP will provide stakeholders or parties to the proposal with an opportunity to revise and resubmit the current plan. In this situation, it is essential for the commission to provide guidance on where the existing proposal fell short so that parties may target their efforts toward modifications that will satisfy the commission. As with a modification, a denial that invites additional filings should include direction regarding process and deadlines, if possible.

Approval of an IDP provides the distribution utility with permission to move forward with the specific elements of the IDP. As such, the utility can incorporate the proposed items such as distributed generation (DG), storage and microgrids into its distribution system planning processes. In addition, these can be factored into the utility's reliability and resiliency decision making processes such as storm response plans and ongoing maintenance schedules. The effects of the IDP are likely to be felt in many of the utility's ongoing reporting obligations and the commission may wish to direct the utility to include information related to the IDP in reliability reports and storm reports.

The commission can also expect to see the results of the IDP in future rate cases. It is uncommon for a commission to preapprove cost recovery of distribution assets before they are used and useful in serving ratepayers.[17] Thus, the implementing utility will need to seek recovery of the

[17] Of course, if a commission has statutory authority or an infrastructure surcharge mechanism, then an IDP order may include cost recovery. Another exception to this is where state statutes allow for recovery of construction

infrastructure elements of the IDP in a future rate case. This will give the commission the opportunity to review the implementation of the IDP for prudence and reasonableness. A base rate case is where a cost-benefit analysis is applied to the completed elements of the IDP, and a commission order approving the IDP may want to specifically reference this later review.

E. Potential Synergies with Other Electric Utility Planning Processes and Regulatory Proceedings

There are a variety of regulatory and planning issues that are not essential to an IDP process but may have a bearing on the inputs or outcomes. Commissions may wish to address some or all of these issues in concert with the decision to impose an IDP requirement.

1. Grid Modernization

In practice, most jurisdictions that are reexamining the traditional distribution utility model begin with initiating some form of inquiry or proceeding on *grid modernization*. Although the term means different things to different stakeholders, generally speaking grid modernization refers to the variety of traditional "poles and wires" solutions (e.g., substations or reclosers) and non-wires alternatives (e.g., combinations of DG, EE, microgrids and storage, including EVs) that can be deployed to meet identified grid needs, adopt updated technologies and make the grid more intelligent and resilient to disturbances. Grid modernization may also help identify the communication and data needs that may be required to enable and manage DER technologies. A grid modernization inquiry can provide valuable information to the commission in establishing an IDP process; however, it is not a necessary component if the commission prefers to move directly into an IDP proceeding.

Like IDP proceedings, a grid modernization proceeding can take any of several forms. If the nature of the proceeding is one in which a utility seeks assurances of cost recovery for distribution system investments but does not develop an IDP, there is the risk of approving utility spending on a technology that is not least cost, least risk or in the best interests of customers when viewing the system as a whole. There is also the risk that a grid modernization process that is not flexible and/or restricts future course changes may impair the adoption of the most beneficial and cost-effective solutions. However, in many jurisdictions grid modernization investigations can occur without a contested case or rulemaking. In these cases, the grid modernization initiative takes the form of workshops and discussions for educational purposes and could produce a report on what was learned. The advantage of combining grid modernization with an IDP process is that it enables the commission to review and analyze multiple options simultaneously to determine which is the best, as opposed to deciding upon just one option that is before the commission for potential rate recovery.

work in progress, in which case some limited cost recovery could be permitted in a rate case prior to the completion of the project.

Commissions will find that a wealth of technical assistance materials on this subject are available from the U.S. Department of Energy (U.S. DOE) and the national energy laboratories through U.S. DOE's *Grid Modernization Initiative*.[18]

2. Interconnection Standards and Procedures

In all the MADRI jurisdictions, utility commissions promulgate and enforce rules governing the interconnection of DERs to the distribution systems of regulated utilities.[19] The rules may establish the standards that DERs must satisfy before being allowed to interconnect, or specify application, review and approval procedures, or both. Utilities themselves generally process interconnection applications, with varying levels of commission oversight from state to state.

In some states inside and outside the region, rapid DER growth is revealing limitations associated with outdated state interconnection standards and utility processes. As a result, more states and utilities are facing backlogs, disputes and stalled projects associated with inefficiencies and time- and resource-intensive protocols. For example, a 2015 study by the National Renewable Energy Laboratory (NREL) found that utilities in five states failed to meet review time requirements for 58% of residential and small commercial solar interconnection applications.[20] Although a number of factors can contribute to interconnection challenges, a prominent one is that customers wanting to adopt DERs have traditionally had limited access to information about the conditions on the grid to help them select optimal and appropriate sites and design projects that are responsive to (and not in violation of) the available hosting capacity at their chosen site. Another barrier to streamlined interconnection processes is the time- and bandwidth-limited utility staff who are tasked with processing increasing volumes of DER interconnection requests. Even requests that are not likely to move forward—because they require costly grid upgrades to accommodate them on the system—still require the time and attention of utility staff to review and study the interconnection applications.

Regulators concerned with ongoing and increasing interconnection challenges can request review of and additional information around the current utility interconnection processes to identify opportunities for greater efficiencies and overall process improvements. Regulators will need to consider whether this exercise makes sense to conduct alongside or in advance of an IDP process, as there are pros and cons to approaching this concurrently versus sequentially. For example, the adoption of modified interconnection standards could encourage or discourage faster deployment of DERs and dictate whether those DERs can be practically used to address distribution system constraints.[21] This argues for considering interconnection practices as part of an IDP. On the other hand, having a separate proceeding to examine interconnection practices

[18] U.S. DOE. (Undated). *Grid Modernization Initiative* [web page]. Washington, DC: U.S. Department of Energy. Retrieved from https://www.energy.gov/grid-modernization-initiative.

[19] The Federal Energy Regulatory Commission (FERC) has jurisdiction over rules for resources that interconnect to the interstate transmission grid.

[20] K. Ardani, Davidson, C., Margolis, R., and Nobler, E. (2015, January). *A state-level comparison of processes and timelines for distributed photovoltaic interconnection in the United States*, p. 13. Golden, CO: National Renewable Energy Laboratory. Retrieved from: https://www.nrel.gov/docs/fy15osti/63556.pdf.

[21] Until recent years, the interconnection standards adopted by virtually all US utilities precluded DERs from actively regulating voltage on the distribution system. Updated interconnection standards now allow DERs to provide this service.

could lead to a deeper examination of technical requirements and faster improvements to rules and current utility practices.

The following is a brief list of interconnection-related considerations regulators may want to address as part of this effort, which can be used to inform and guide next steps on IDP or broader interconnection reform:

- Does the state have interconnection standards that apply uniformly to all utilities within the commission's jurisdiction?
- Are the interconnection standards applicable to all projects, or are there size limitations that may prevent state jurisdictional projects from having a clear path to interconnection?
- What DERs are covered by the interconnection standards? Are microgrids covered?
- Is energy storage explicitly addressed, defined and given a clear path to proceed through the interconnection review process?
- What are the size limits for the different levels of review?
- Is there an option to have expedited review for small, inverter-based systems unlikely to trigger adverse system impacts (e.g., under 25 kilowatts)?
- Is there an option for a fast-track review process for larger DERs (e.g., up to 5 megawatts) that are unlikely to require system upgrades and/or negatively impact the safety and reliability of the grid?
- What technical screens are applied for the fast-track review process?
- Is there a transparent supplemental review process for interconnection applications that fail the fast-track screens?[22]
- Is there a preapplication report that allows DER customers to access (for a reasonable fee) a preliminary grid information report prior to submitting a full interconnection application?[23]
- Is the utility meeting current timelines (if established)? If not, why?
- What methods, approaches and tools are in place to improve the timeliness of the interconnection process (e.g., electronic application submittal, tracking and signatures, online payment of fees, describing possible remedies if an application is denied, etc.)?

22 Several states, including Ohio, Massachusetts, Illinois, Iowa and California, have adopted this transparent supplemental review process. See IREC (2017, August). *Priority considerations for interconnection standards: A quick reference guide for utility regulators*. New York: Interstate Renewable Energy Council. Retrieved from: https://irecusa.org/priority-considerations-for-interconnection-standards/.

23 Preapplication reports provide readily available information about a particular point of interconnection on a utility's system. The information generally provided includes items such as the circuit and substation voltage, the amount of already connected and queued generation, the distance of the proposed point of interconnection to the substation and peak and minimum load data. These reports are available in a handful of states where they help guide customers. But they have limitations: they do not contain any actual system analysis and can take over a month to receive. See McConnell E., and Malina, C. (2017, January 31). *Knowledge is power: Access to grid data improves the interconnection experience for all*. Boston: Greentech Media. Retrieved from: https://www.greentechmedia.com/articles/read/knowledge-is-power-access-to-grid-data-and-improvesthe-interconnection-exp#gs.SVY9Tdw; Peterson, Z. (2017, June). The State of Pre-Application Reports [web page]. National Renewable Energy Laboratory/Distributed Generation Integration Collaborative. Retrieved from: https://www.nrel.gov/dgic/interconnection-insights-2017-07.html.

- Is there an explicit process to clear projects from the interconnection queue if they do not progress?
- Are there clear timelines for construction of upgrades or meter installs?
- Is there a clear, efficient and fair dispute resolution process?
- Is there a transparent reporting process and publication of the interconnection queue to allow customers to see how many projects are in the queue?
- Does the utility publish and make publicly available distribution system maps (i.e., heat maps, hosting capacity maps)?[24]
- Has the commission considered a performance incentive or penalty for the utility's performance in approving interconnection applications?

To the extent regulators are overseeing and guiding a hosting capacity analysis (HCA) effort, the following questions (in addition to those identified in Section IV.D) can help inform whether the HCA has the capability and functionality necessary to meaningfully address broader interconnection reforms:

- Can the HCA methodology be used to provide reliable data about the hosting capacity of nodes across the circuit to streamline and expedite the review of interconnection applications?
- When a customer seeks to interconnect at a given node, can he or she use the HCA to determine if the proposed DER project falls within the hosting capacity value for that location?
- If yes, can the project be approved to interconnect with little to no additional review or study with the assurance that it will not compromise system safety or reliability?
- Can the HCA be used *in lieu of* interconnection screens in the fast track or supplemental review process?
- If the DER project falls outside the identified hosting capacity, can it be directed to the study process, or can the utility provide the customer with information that allows her to redesign the project to fit within the hosting capacity limits (and/or address known constraints through system or operational redesign)?
- If the DER project falls outside the identified hosting capacity, is it feasible and cost effective to deploy energy efficiency resources to increase the hosting capacity?
- Can customers use the detailed HCA data to identify potential project alternatives or mitigations that would help them avoid hosting capacity limits, such as use of on-site storage to shift peak demand, advanced inverters or interconnection agreements that allow curtailment during limited peak hours of the year?

A robust review of interconnection standards and performance can be an important exercise for regulators seeking to better understand how a utility is performing in the context of integrating DERs on the grid. Where interconnection challenges exist, and even in advance of any major challenges, there may be ripe opportunities to leverage the IDP process to evaluate and improve state standards and utility protocols and adopt new tools and approaches to better accommodate,

24 Hernandez, M. (2018, June 26). New grid transparency tools improve distributed generation siting [opinion]. Utility Dive. Retrieved from: https://www.utilitydive.com/news/new-grid-transparency-tools-improve-distributed-generation-siting/526500/.

streamline and optimize DER integration. Taking initial steps to align the state and utility with well-vetted and proven interconnection practices can help ensure IDP and other grid modernization efforts are impactful and meaningful over the long term.

3. Consideration of Creating a Distribution System Operator

Growth in the deployment of DERs could eventually alter the need for balancing services. If one imagines a not too distant future where millions of EVs are plugged into the distribution system, PV systems with smart inverters are ubiquitous, and flexible loads are available in almost every building to provide DR services, one can also imagine that balancing problems and balancing solutions could become more localized than they are today. Balancing services managed at the distribution system level could someday supplement or complement the balancing services that are managed today almost entirely at the bulk power system level.

Some power sector stakeholders have suggested that the essential role of utilities, and the way they earn profits, could be transformed.[25] Instead of managing the grid as a one-way delivery system that moves power from wholesale suppliers to the utility's retail customers, utilities could manage the grid as a platform for direct transactions between suppliers and customers and earn revenue from those who use the platform. Platform revenues would provide utilities with a new business model for interconnecting and coordinating DER operations on the distribution system.

A distribution system operator (DSO) can be created and operate somewhat analogously to a regional transmission system operator (RTO) by creating a platform for the operation of the distribution grid. The utility can take on the role of DSO for its service territory, much like in New York, or the DSO can be an independent system operator (ISO). In April 2014, the New York Commission launched its Reforming the Energy Vision (NY REV) process with an order on its first track.[26] This proceeding addressed the roles of the distribution companies, third parties, consumers and generators. Like the MADRI states, New York is restructured. The order established the utilities as distributed system platform providers (DSP), which the commission viewed as representing an expansion of the existing obligations. The commission also recognized that as a result of this expanded role and the change in the utility business model, regulatory changes would be needed, such as creating an earnings adjustment mechanism that operates like a performance incentive. The DSP is designed to provide an intelligent network platform with both obligations and incentives to support DERs through a fair, open and transparent transactive market. It is responsible for integrated system planning, grid operation and market operations, structures and products. The commission defined the DSP as "an intelligent network platform that will provide, safe, reliable and efficient electric services by integrating diverse resources to

[25] Former Pennsylvania and FERC commissioner Robert Powelson, for example, told a conference audience in 2017: "When we think about the grid of the future, we have to think of it in terms of IT platforms that turn passive networks into intelligence and provide a vibrant marketplace where demand and supply-side resources are optimized and they don't sacrifice reliability." Quoted in: Unger, D. J. (2017, October 5). 'Platform' model will be key for Illinois' future power grid [news article]. Energy News Network. Retrieved from: https://energynews.us/2017/10/05/midwest/platform-model-will-be-key-for-illinois-future-power-grid/.

[26] New York Public Service Commission (2015, February 26). *Proceeding on the motion of the commission in regard to reforming the energy vision*. Case No. 14-M-010. Order adopting Regulatory Policy Framework and Implementation Plan.

meet customers' and society's needs. The DSP fosters broad market activity that monetizes system and social values, by enabling active customer and third-party engagement that is aligned with the wholesale market and bulk power system."[27]

One advantage of a utility taking on the role of DSO is that it represents an expansion of existing utility responsibilities, and so incrementally, these new responsibilities may be more easily handled and quickly implemented by a utility. Further, putting the utility in this role can help solidify DERs as a core part of the system. Finally, the utility has more comprehensive knowledge than any other party of real-time system conditions across the entire distribution grid.

The drawbacks of having the utility act as the DSO include the historical reluctance on the part of utilities to embrace DERs, although this can be at least partially addressed through a decoupling mechanism or performance-based regulation, as discussed in Section V.B below. A significant concern that would have to be overcome is the utilities lack of experience or skill with respect to DERs and DER markets. Finally, the utilities as the DSO may be in a position to exercise market power to advance their own interests and suppress innovation. To counteract this, a code of conduct would have to be put in place and enforced by the commission.[28]

An independent DSO could operate on a statewide basis as opposed to a utility service territory basis and coordinate activities across the state. This would give utilities a little more latitude to participate in the DER market. While concerns regarding market power would not be eliminated, they may be mitigated by having a statewide DSO. Appropriate codes of conduct would still be needed. Moreover, coordinating the actions of an RTO with a single statewide DSO would be less complex for the RTO and might create a greater range of operational possibilities, in the same manner that larger balancing areas allow for more efficient use of generation and transmission resources. A statewide DSO may also benefit from certain economies of scale with respect to its operational costs. Coordination between the RTO and DSO could optimize the utilization of DERs to perform double duty. In a generic proceeding that leads up to the development of IDP regulations, this would be a good question to posit and seek expert opinion to better inform the commission in deciding what direction to take.

4. Utility Business Models and Alternative Ratemaking Options

The IDP process and the incorporation of DERs usher in a new way to consider the utility business model so that the utility's financial interests are aligned with the public interest. Investor-owned utilities have a fiduciary duty to their shareholders and earn a return for their investors through a return on their rate base, which consists largely of the utilities' capital investments. Thus, the incentive for a utility is to increase its rate base, and when given the option, a utility might choose to invest more in traditional infrastructure solutions to enhance its grid, as opposed to a similarly viable DER option. Therefore, in the context of considering developing an IDP process, commissions may want to consider alternative forms of ratemaking

27 Ibid.

28 Migden-Ostrander, J. (2015, December). Power sector reform: Codes of conduct for the future. *Electricity Journal*, 28(10), 69–79. Retrieved from: https://www.sciencedirect.com/science/article/pii/S1040619015002274.

and utility incentive structures, to better align financial incentives with cost-effective deployment of DERs.

One theory of regulation is that all regulation is incentive regulation, and a utility will take the course of action that provides it with the greatest reward for its shareholders and for the financial health of its company and the integrity of its system. Performance based regulation (PBR) has been introduced in a number of jurisdictions. The objective of PBR is to better align the utility's interest with public interests to create a win-win scenario. There are many ways to design a PBR incentive. These include adding an incentive payment for and/or assessing a penalty on the return on equity for positive or negative performance, respectively. Under another methodology, the commission can establish a lower return in a rate case and provide the utility with the incentive to increase the return by taking certain actions. The amount of the potential penalty or reward needs to be clearly established. PBR is a powerful tool and needs to be carefully thought through to avoid unintended consequences.[29]

PBR also requires that the measures subject to performance regulation be unambiguous with clear metrics and targets. Which performance metrics to use, and how to measure them, should be set forth in an order along with the target the utility needs to achieve. With respect to IDP, the goal of PBR is to remove barriers and encourage utilities to view distribution upgrades from a new lens where NWAs can provide lower-cost solutions that also enhance clean energy objectives. Examples of possible performance metrics could include increased EE or DR targets, improving the process for interconnection of DG or microgrids to the utility's system, successfully designing and marketing time-varying rates to reduce peak demand and soliciting DER solutions for system upgrades when it is more cost effective to do so.

Another alternative ratemaking option to address utility lost revenues that can occur as a result of customers taking advantage of DER opportunities is decoupling, in which actual revenues are reconciled periodically with authorized revenues to ensure that the utility recovers the revenue requirements authorized in its last rate case. This can result in a credit or debit to the utility. Decoupling is explained in greater detail in Section V.B.2.

Allowing utilities to offer value-added services would create the possibility for the utility to earn revenues by providing a broad range of services enabled by the modern grid. The lines between basic and value-added distribution services are still being drawn and questions remain about the role of utilities vis-à-vis third parties in the provision of these value-added services.

5. Coordination with Resource and Transmission Planning

PJM Interconnection is the RTO that serves the MADRI jurisdictions.[30] In that role, PJM is responsible for maintaining reliability of the bulk power system at the most efficient cost. It utilizes markets to ensure generation supply meets demand levels in real time and to incentivize

[29] An example would be a utility focusing mostly on items subject to a performance metric to the detriment of paying attention to other important areas of its operations for which no performance metric has been established.
[30] The entire PJM footprint encompasses all or parts of 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia) and the District of Columbia.

investment in resources to retain the supply and demand balance in the future. Additionally, its long-term regional planning process seeks to ensure that power flows efficiently from generation supply sources to the load across the PJM region.

At a minimum, PJM must ensure that bulk power system reliability is not impacted by DER deployment. Optimally, PJM will seek to harness DER capabilities to enhance wholesale grid reliability and market efficiency. To meet its responsibility of ensuring reliability at the most efficient cost, PJM may need to gain greater visibility into the location and capability of DERs; learn how to better forecast DER operations in real time as well as in future years; work with distribution utilities to ensure DER smart inverter settings do not exacerbate transmission disturbances; and explore whether the retail market and wholesale market may be aligned in a manner that would allow greater coordination of the resources in response to real-time wholesale grid needs. Accomplishing greater visibility, measuring and forecast capabilities and operational incentive alignment should benefit consumers through wholesale grid reliability enhancement and cost savings.

Understanding how DERs are operated in real time would enable PJM to make better wholesale market dispatch decisions. If there are sufficient DERs operating and reducing wholesale demand in a location, PJM could avoid dispatching the next costlier resource to meet the demand. Anticipating the future deployment of DERs could reduce the long-term load forecast PJM relies upon in committing capacity resources and making decisions about transmission grid enhancements to meet future expected demand.

If PJM knows where DERs are located and understands how they are operated, PJM could evaluate how DERs could potentially contribute to bulk power system reliability. This would enable PJM's operators to work with distribution companies to coordinate operations, which could be especially valuable should a circumstance arise where the DER operation might enable PJM to avoid or more quickly and effectively respond to a wholesale grid emergency. Therefore, knowing the location and quantity of available dispatchable and non-dispatchable DERs as well as having the ability to communicate, either directly or through the utility (or an aggregator), would be extremely beneficial. To be efficient, such communications capability must leverage open technical standards and open communications protocols.

When working on DG forecasting, PJM has focused its efforts to date on solar technology, as non-wholesale solar PV installations and the associated growth trend with that technology represent the most significant form of DG today. To keep supply and demand in balance to maintain reliability in real time, with the assistance of a vendor, PJM currently forecasts the hourly output of existing installed non-wholesale solar to factor and incorporate those expectations into its electricity market dispatch decisions. For example, if PJM expects distributed solar generation to offset load it would otherwise need to serve through wholesale generation, this will reduce the amount of wholesale generation that needs to be committed to operate. To the extent that IDP also envisions hourly and long-term solar forecasts, it may be helpful to coordinate these forecasts with PJM.

To ensure that PJM does not overcommit resources to meet its resource adequacy requirements in the capacity market and to ensure it does not overbuild transmission facilities, PJM refined its long-term load forecast that feeds those processes to factor in expected DER deployment. In 2016, PJM incorporated the impact of behind-the-meter distributed solar generation into the forecast. PJM considered historical installations that are tracked in the PJM Generator Attributes Tracking System, and it relied on a vendor to provide projected future growth of behind-the-meter solar. The vendor's forecast is broken down by transmission zone and considers factors such as: state renewable mandates and targets, tax credits, net metering policy, solar capital costs and electricity prices. PJM then performs calculations to equate the sum of historical installations and projected installations (measured in in megawatt-hours or MWh) to an impact on the peak load forecast (measured in megawatts or MW).

These principles apply to demand-side resources as well. As a part of the 2016 revision to its load forecast, PJM stated that the most important methodological change was the addition of variables that capture trends in efficient-appliance saturation and energy usage.[31] Utilities and PJM can communicate proactively and can provide data to one another on planned energy efficiency deployment and on energy efficiency's participation and performance in the wholesale market.

The accuracy of both real-time and long-term load forecasting methods would be improved with greater visibility into behind-the-meter solar installations and deployment of demand-side resources, including historical output, location and planned deployments. Additionally, any ability to receive telemetered output data (even aggregated data) through coordination with utilities across the PJM region or the resource developers/aggregators would greatly enhance PJM's forecasting capabilities and benefit reliability, market and transmission build-out efficiency. To be most effective, such data transfers should leverage open technical standards and open communications protocols. Commissions can consider how additional information and data may be provided to PJM to achieve the reliability and efficiency benefits.

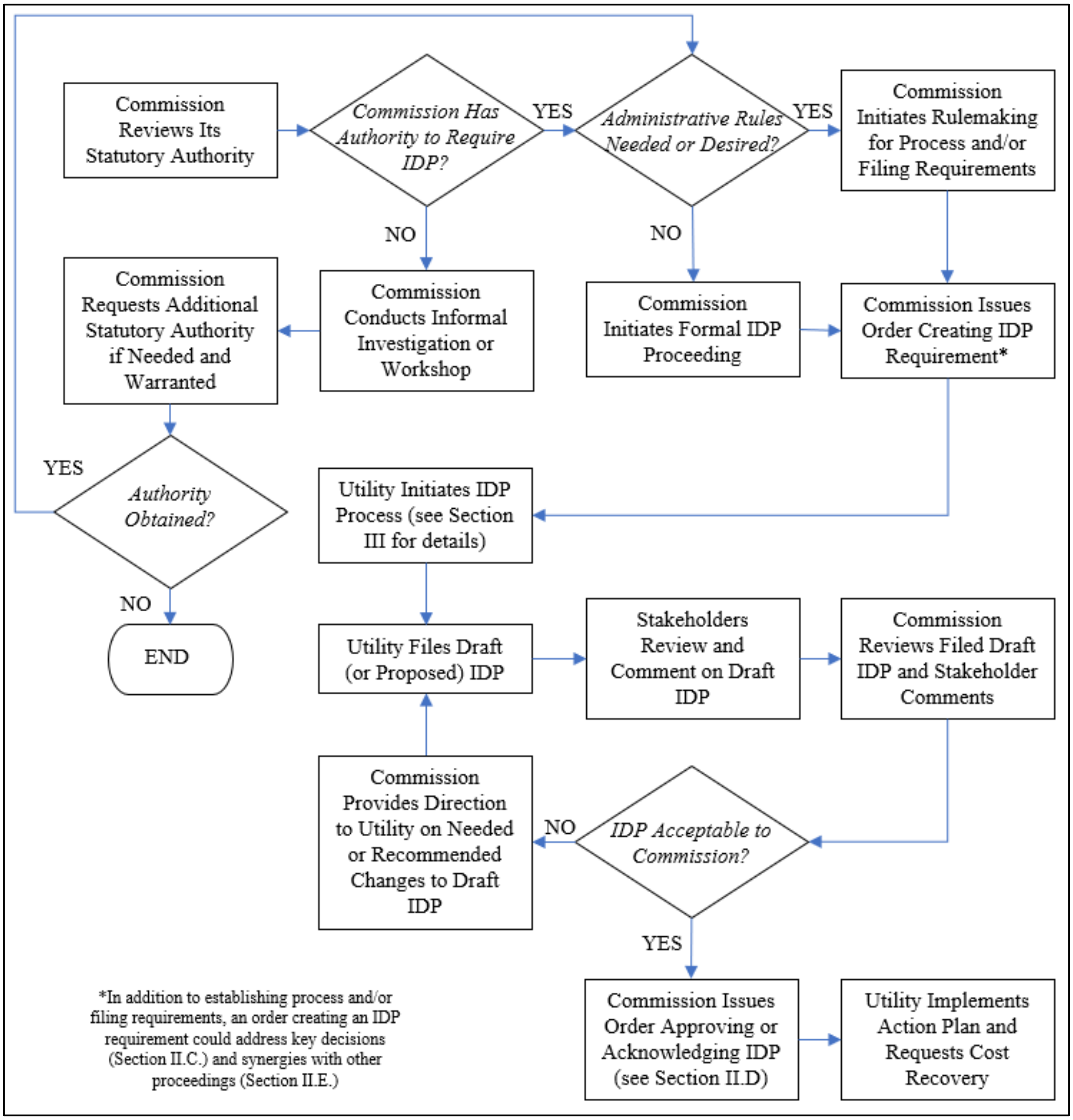
NOTE: Perspectives of PJM staff on IDP and the need for coordinated planning are presented in Appendix 1 to this guidance document.

F. Summary of the Commission Oversight Process

Figure 1 presents a flowchart summarizing the generic steps a commission might take in the process of developing and implementing an IDP requirement. Because the statutory authorities and institutional norms of every commission are unique, Figure 1 should be viewed simply as an illustrative example. Each commission can add or subtract steps in this process that are consistent with its own authorities, norms, capacity, and goals.

[31] PJM Interconnection. (2016.) *Load forecasting model whitepaper*. Norristown, PA: PJM Interconnection. Retrieved from: https://www.pjm.com/~/media/library/reports-notices/load-forecast/2016-load-forecast-whitepaper.ashx.

Figure 1: Commission Oversight of an IDP Requirement



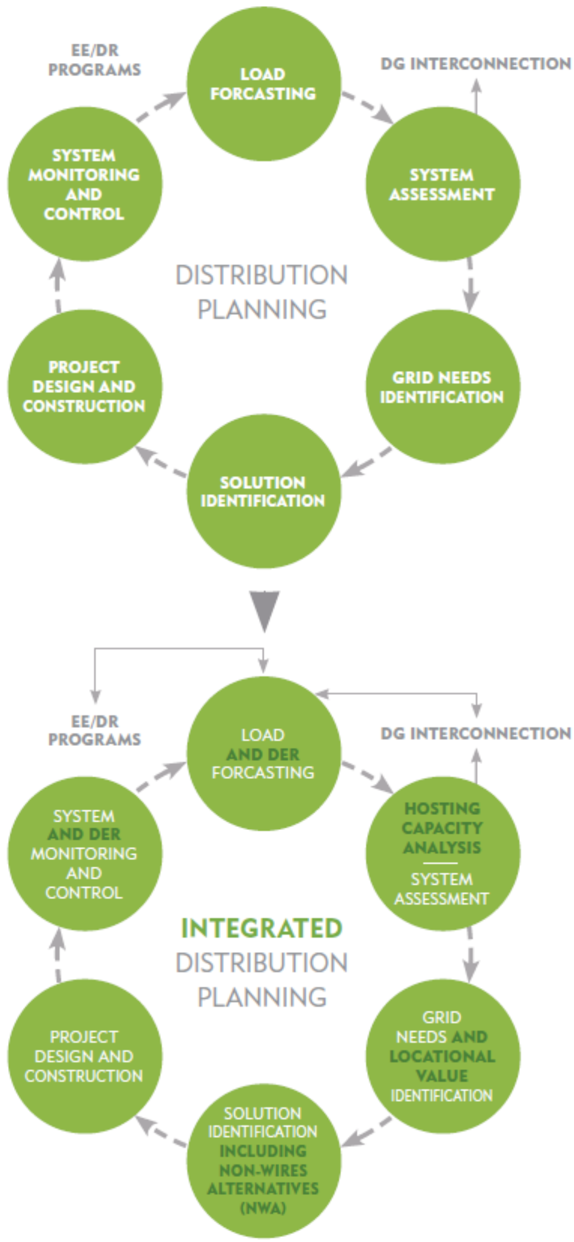
III. PROCESS FOR DEVELOPING AN IDP

The typical distribution planning process practiced by utilities for decades has been largely an internal exercise, with little regulatory oversight until the utility asks for cost recovery in a rate case. There can be exceptions. Notably, in some jurisdictions a limited set of projects may require preconstruction regulatory approval.

In most cases, regulatory commissions that adopt a formal IDP requirement will want to prescribe, or at least outline, a *process* for the development of such plans by utilities. Because distribution system planning has traditionally been entrusted to utilities, with little *a priori* oversight or public engagement, commissions may wish to review current practices of their utilities before designing a new planning process.

Figure 2 illustrates how a typical distribution planning process, shown at the top of the figure, compares to an IDP process as shown at the bottom of the figure. The most essential factor that separates an IDP from a traditional distribution planning process is the integrated consideration of all possible solutions to identified needs. The goal remains to find the least costly, sufficiently safe and reliable option for ratepayers, but in IDP the preferred option may or may not include transmission or distribution infrastructure and may or may not be utility owned.

Figure 2: Comparison of Typical Distribution Planning Process and IDP[32]



State commissions may want to consider additional or different steps or give utilities some latitude in designing their own IDP process.

Some of the steps in the IDP process will require sophisticated software tools. Some of the necessary tools can be mapped to various utility systems, such as advanced distribution management systems and DER management systems, but others are standalone modeling applications. These technologies are at varying states of maturity — with some being fully

32 Volkmann, C. (2018). *Integrated distribution planning: A path forward*. GridLab. Retrieved from: https://gridlab.org/publications/.

commercialized and others in the research and development stage. The technology requirements to perform IDP will vary based on the planning objectives and the stage of DER penetration on the grid. As such, the technology needs will evolve as IDP goals become more sophisticated and new stages of DER penetration are reached. A U.S. DOE report, *Modern Distribution Grid, Volume II: Advanced Technology Maturity Assessment,* provides a helpful framework for identifying technology needs for IDP planning.[33]

The remainder of this section presents a brief explanation of the most important and universal of IDP process steps, along with a characterization of the kinds of software technologies that may be needed to complete each step. Details about the content of the written and filed IDP, and some of the challenges inherent in developing that content, are presented in later sections of this guide.

A. Forecast of Load and DER Deployment

The planning process begins with the creation of long-term (or at least medium-term) forecasts of load and DER deployment for the utility service territory, which when combined result in a net load forecast. In this guide, net load means the gross customer load minus any portion that will be served by behind-the-meter DERs. Net load is the load that the distribution system "sees" and the utility serves.

Forecasting is foundational to the IDP process because it defines the needs of the system over the planning period. Traditional forecasting tools have focused on customer load growth rather than DERs and mainly relied on demographic and economic data and energy usage trends. However, as DERs become more common, new models become necessary to accurately forecast DER adoption trends and their impact on future net loads. These DER adoption models incorporate input about the economics of DER technology (capital costs, O&M costs, performance data), policies supporting DER adoption and even rate designs. Technologies related to forecasting include load forecasting models and DER forecasting models.[34]

The hallmark of an IDP process is granularity. The forecasts will need to be spatially and temporally differentiated to enable a proper assessment of system needs and potential solutions. Net demand forecasts will need to identify the annual systemwide peak demand (measured in kW or MW) and the timing of that peak, as well as the annual coincident and non-coincident peak demand at different nodes on the distribution system that are relevant for planning purposes (e.g., feeders or possibly substations) and the timing of the non-coincident peaks. Although distribution system planning tends to focus primarily on ensuring adequate capacity exists to serve peak demands, for an IDP it may also be necessary to forecast net energy usage (measured in kWh or MWh) on annual, seasonal, monthly, or even daily timescales to enable proper evaluation of NWAs. Additional forecast data may be needed in some circumstances, for

33 U.S. DOE (2017). *Modern distribution grid, volume II: Advanced technology maturity assessment*. Washington, DC: U.S. Department of Energy. Retrieved from: https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-II_v1_1.pdf.

34 Figure 2 indicates the connection between load and DER forecasting and monitored EE and DR program results. Although this guide retains the original figure from the cited source document, unchanged, we note here that monitored results of other programs (e.g., programs promoting DG, storage, EVs, or microgrids) could also impact forecasting.

example if more complex power flow analyses are required to assess how the system might respond to a large DER installation.

Commissions will also need to decide whether to direct utilities to engage subject matter experts or stakeholders in developing these forecasts.

B. Assessment of System Conditions and Capabilities

The second major step in the planning process is to characterize the capabilities and limitations of the existing distribution system. This requires a detailed review of the capacity of existing infrastructure, as well as known problems, limitations and areas of concern. For example, some utilities will want (or be required) to identify the number and locations of transformers that contain polychlorinated biphenyls (PCBs) or devices that contain sulfur hexafluoride (SF_6).[35]

One aspect of an IDP that sets it apart from traditional planning processes is that this step of an IDP process also includes (or should include) an assessment of the hosting capacity of the existing distribution system. (Hosting capacity analysis and hosting capacity maps are discussed in greater detail in Section IV.D) Because system conditions and hosting capacity can vary from one line segment to the next, the assessment undertaken in this step of the IDP process must be very detailed and spatially granular. This step of the IDP process, like the traditional distribution planning process, will normally be completed by technical experts within the utility, possibly with consultation from outside technical experts.

C. Identification of Projected System Needs and Opportunities

In the next step, the assessment of current system capabilities is compared with the forecasts of load and DER deployment (or net load) to identify locations on the distribution system where the forecasted needs of customers will exceed existing capacity and capabilities.[36] At the same time, this analysis can also identify locations where deployment of additional DERs or traditional assets would have the greatest value or will be necessary to achieve any established environmental or climate goals of the state. Here again, the identification of system needs and locational value will normally be completed by technical experts.

Power flow analysis is a critical element of IDP that identifies the operational characteristics of the existing and planned distribution grid, including how conditions change in relation to customer load and DER adoption scenarios. Power flow analysis estimates voltages, currents, and real and reactive power flow, which are used to identify capacity constraints on the distribution system and options to resolve them. Power flow analysis software will contain the following capabilities:

- Peak capacity planning study

[35] PCBs are persistent bioaccumulative toxins and SF_6 is the most potent of all greenhouse gases. Some utilities are phasing out the use of PCBs and implementing plans to minimize leaks of SF_6.

[36] Planners might wish to take a broad view toward defining the "forecasted needs of customers." Although this term certainly encompasses traditional needs for electric capacity and energy, a broader interpretation could (for example) also encompass the need to bolster resilience at critical infrastructure facilities or the need to achieve state environmental and climate goals.

- Voltage drop calculator
- Ampacity calculator
- Contingency and restoration tool
- Reliability study tool
- Time series power flow analysis
- Balanced and unbalanced power flow analysis
- Load profile study tool
- Stochastic analysis tool
- Volt-var study tool

Power quality assessment studies the impact to power quality of increased penetration of intermittent renewables and inverter-based DERs on the distribution system, including voltage sag and harmonic disturbances. Violations of power quality rules can reduce the efficiency of the distribution system and damage sensitive equipment. The software packages for power quality assessment typically include the following functionality:

- Voltage sag and swell study tool
- Harmonics study tool

Fault analysis is used to identify anomalies in the flow of current on the distribution system. In an IDP context, fault analysis can model where faults are likely to occur on the system and define strategies to resolve power system failures. Fault analysis software contains the following modules:

- Arc flash hazard analysis tool
- Protection coordination study tool
- Fault probability analysis

Advanced optimization tools are being developed to identify the optimal size, location and capabilities of DERs that can provide grid services — including NWAs and power quality and reliability support — subject to technical distribution constraints. Advanced optimization tool kits model power flow for DER operations under maximum and minimum load conditions and for multiple planning scenarios to identify potential reliability violations. Distribution planners can use the modeling outputs from a DER impact evaluation tool to make sure that hosting capacity limits are not exceeded, as well as to better value DERs and plan for NWAs.[37]

D. Evaluation of Options and Selection of Preferred Solutions

After identifying forecasted needs, the planning process turns to a search for least-cost solutions to satisfy those needs. The essence of an IDP, and what sets it apart from a traditional distribution system planning process, is the *integrated* approach. All options to address

[37] DER optimization tools are commercially available from multiple vendors, as a simple internet search will reveal. This guide cannot endorse or recommend any specific commercial products, but we note *for illustrative purposes* that the U.S. DOE's Grid Modernization Laboratory Consortium is currently developing a *DER Siting and Optimization Tool to Enable Large Scale Deployment of DER in California*. Information retrieved from: https://building-microgrid.lbl.gov/projects/der-siting-and-optimization-tool-enable.

forecasted needs should be considered on a fair and equal footing. This includes not just distribution infrastructure investments, but also greater use of NWAs such as:

- EE and DR programs that encourage customers to reduce energy consumption, shift or reduce their peak demand or provide ancillary services;
- Utility investment in DG, energy storage, microgrids and EV charging infrastructure, where such investments are not precluded by state policies or regulations;
- Customer and third-party investments in DG, energy storage, microgrids, EV charging infrastructure and other behind-the-meter technologies; and
- Reformed retail rate designs that encourage customers to shift or reduce their peak demand.

A common approach to the evaluation of options is to first characterize the capabilities and costs of potential solutions in a generic fashion, and then identify which options are potentially suitable for addressing specific forecasted needs (i.e., the benefits of the option exceed the costs).[38] To ensure that all options are considered, distribution planning departments should coordinate with EE program planners and with other DER planning teams.[39] Utilities may benefit from engaging outside experts in the characterization of some options, and commissions could consider whether to require or encourage such consultations. For example, utilities may benefit from consulting with third-party energy storage solution providers to get a current and accurate assessment of the costs and capabilities of these rapidly evolving technologies. In pursuing this route, however, utilities should be encouraged to consult with multiple vendors to get a broad perspective on the range of options and costs.

Cost should not be the sole criterion used to evaluate options. Risk-informed decision support tools can also play a role.[40] These tools use a consistent methodology to assign a risk reduction score to grid projects or NWAs. Risks to include in such a score can include reliability, resilience, DER interconnection delay, safety, or performance metrics. Weightings can be assigned to various risks to denote priorities. Grid projects or NWAs can then be ranked by a combination of their ability to reduce risk and their projected costs, providing a prioritized list of grid projects or NWAs.

[38] Methodologies for assessing cost-effectiveness are beyond the scope of this paper but interested readers will find a thorough and up-to-date treatment of cost-effectiveness issues for EE in a 2017 *National Standard Practice Manual (NSPM)*. An NSPM for other DERs is slated for publication in 2020. See: National Efficiency Screening Project. (2017, May). *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources*. Retrieved from: https://nationalefficiencyscreening.org/national-standard-practice-manual/.

[39] For example, at Eversource, a Connecticut electric utility, the process to upgrade distribution feeders begins with the asset management department but is coordinated with the field engineering, load forecasting, and company management teams. Load forecasting for EE is additionally coordinated with ISO New England's EE forecast Working Group. See: Baatz, B., Relf, G., and Nowak, S. (2018, February). *The role of energy efficiency in a distributed energy future*. Washington, DC: American Council for an Energy-Efficient Economy. Retrieved from: https://aceee.org/research-report/u1802.

[40] Alvarez, P., Ericson, S., and Stephens, D. (2019, July). The Rush to Modernize: Distribution Planning, Performance Measurement. *Public Utilities Fortnightly*. Retrieved from: https://www.fortnightly.com/fortnightly/2019/07/rush-modernize.

Non-Wires Alternative Example

In recent years, some utilities have begun to consider NWAs as a solution to specific, localized needs. Instead of being concerned about peak demand exceeding power supply of the entire grid, the focus is on a specific circuit or load area of the distribution grid. As is described below in Section IV.E.2, one of the five reasons that grid components need to be replaced is when the load forecast for a circuit, group of circuits or substation shows that expected load growth in the coming years is likely to result in a peak load level that reaches or exceeds the power delivery capability of this portion of the grid. In some states, regulators have ruled that instead of simply proceeding to upgrade the grid, the utility must first solicit competitive bids from contractors who offer an NWA load reduction for a specific number of years, to defer the need for the utility to undertake the very expensive grid-upgrade project. If the deferral via the NWA solution results in a smaller utility bill impact, the utility must proceed with that approach. Instead of offering a preset payment to participants who allow their equipment to be used to reduce the load on the grid, as happens with a traditional DR program, the utility typically invites competitive bids and allows the bidders to determine the mix of DERs that will be deployed and used.

As one part of New York's *Reforming the Energy Vision* initiative (NY REV), the NY utilities developed suitability criteria for NWA projects. The utilities developed criteria to determine: (1) the type of projects best suited for NWAs; (2) projects with adequate lead times to allow an NWA procurement to be held; and (3) the minimum cost threshold warranted to run a procurement process. Each of the NY utilities has chosen different thresholds for these three criteria. An example from Central Hudson is included in Table 1.

Table 1: Sample NWA Project Suitability Criteria from Central Hudson[1]

<table>
<tr><td>Criteria</td><td colspan="2">Potential Elements Addressed</td></tr>
<tr><td>Project Type Suitability</td><td colspan="2">Project types include load relief and reliability. Other categories currently have minimal suitability and will be reviewed as suitability changes due to state policy or technological changes.</td></tr>
<tr><td rowspan="2">Timeline Suitability</td><td>Large Project</td><td>36 to 60 months</td></tr>
<tr><td>Small Project</td><td>18 to 24 months</td></tr>
<tr><td rowspan="2">Cost Suitability</td><td>Large Project</td><td>≥ $1M</td></tr>
<tr><td>Small Project</td><td>≥ $300k</td></tr>
</table>

Some states may wish to employ an iterative approach in which options are initially evaluated using assumed costs and capabilities, but those assumptions are tested through a formal request for information (RFI) from solution providers. Alternatively, the utility could issue a request for proposals (RFP) to solicit competitive bids. Assumptions about costs and capabilities can then be replaced with actual data from an RFI or RFP.

When all the suitable options have been assessed, a preferred solution or set of solutions can be chosen based on consideration of costs, capabilities, timing, uncertainties and risks. Most states will want to ensure that some degree of stakeholder involvement precedes any final decisions about preferred solutions. If a risk-informed decision support tool has been used and a prioritized list of options created, stakeholders will have a better understanding of what additional value they'd receive for capital budget increases, as well as what reduction in value they'd give up for capital budget cuts. Through this process, much like a resource planning process for generation, the greatest benefits (in terms of risk reduction) for the least cost can be secured for customers.

E. Implementation of Solutions

Following any required stakeholder review or regulatory approvals of the IDP, the utility will begin to implement the near-term projects and actions identified in the plan. More detailed assessments of specific projects may be necessary, and some types of projects (e.g., construction of a new substation) may require additional preconstruction approvals from the commission, from environmental regulators, or from local officials.

F. Ongoing System Monitoring

After each project or action is completed, and on an ongoing basis, the utility will need to monitor and report to the commission regularly on system conditions to determine if the system need has been met and to identify new capacity constraints to address in future updates to the IDP. It is also important to monitor load and DER deployment on an ongoing basis to determine if the forecasts that are used to identify system needs require modifications.

IV. CONTENT OF AN IDP

This section describes the content that regulators might reasonably expect to see included in a written IDP report that is submitted for their acceptance or approval. The information need not be presented in an IDP in the order that it is described in this report. Some commissions will choose to specify the required content of the IDP in an order, while others may prefer to promulgate regulations that set forth the filing requirements for an IDP. The key content elements of an IDP include a description of the current system, a summary of planned retirements and committed future resource replacements or additions, a load and DER forecast, a hosting capacity analysis, a needs assessment and risk analysis, an evaluation of options for meeting forecasted needs, an action plan, and a summary of stakeholder engagement. Each element is explained in detail below.

A. Description of the Current System

The purpose of a utility's distribution grid is to safely and reliably deliver power to end-use customers. To accomplish this, the utility designs, constructs and maintains a carefully engineered assemblage of equipment: electrical conductors; electrical insulators; transformers (sometimes with associated cooling devices) to establish a desired voltage level on a specific branch circuit; control devices such as breakers and relays to interrupt the flow of power when this is needed; impedances (inductances and capacitors) to maintain power quality; instrumentation such as voltage, current, power factor and temperature sensors; power meters; computers, data-recording device and data-display screens; supporting structures (e.g., poles and crossarms, steel towers, concrete pads); communication devices; and security infrastructure such as fences around substations, video cameras and intrusion alarms. Each of the grid components has a capability limit in the form of maximum current-carrying capability, maximum operating voltage and temperature and, in the case of supporting structures and insulators, maximum mechanical loading. Large, high-voltage transformers and associated control devices and sensors are installed at substations that are often the interface between the transmission grid and the distribution grid. Circuits branch out from the substations. Smaller transformers, operating at voltages from 240 volts up to about 10 kV, are installed at points along the circuits and where end-use customers are located.

The IDP should describe the utility service territory and summarize information about the number of customers served by the utility. The IDP should also provide data about key distribution system parameters, including:

- ☐ Status of AMI deployment by customer class;
- ☐ Miles of underground and overhead wires, possibly categorized by voltage;
- ☐ Number and capacity of distribution substations (possibly also noting the number of devices that contain SF_6);
- ☐ Number and capacity of distribution transformers (possibly also noting how many contain PCBs);
- ☐ Monitoring and measurement capabilities on the distribution system, for example the percentage of substations and feeders for which the utility has real-time supervisory control and data acquisition (SCADA) capability;
- ☐ Historical coincident and noncoincident peak loads on the distribution system;

- ☐ Estimated or known distribution system line losses;
- ☐ Amount of DG installed on the system (number of systems and nameplate capacity in kilowatts or kW) by generator types, noting geographic locations as needed for planning purposes;
- ☐ Amount and locations of distributed storage installed on the system (number of systems and ratings, measured in kilowatts and kilowatt-hours or kW and kWh);
- ☐ Number of EVs in each region of the service territory;
- ☐ Number, capacity, and locations of public and, where data are available, private EV-charging stations;
- ☐ Number, capabilities, and locations of any islandable microgrids;
- ☐ Recent history of investment in demand-side management (EE and DR) and results (energy and demand savings); and
- ☐ Recent history of distribution system investments (in dollars) categorized by reason for investment (e.g., replace failing equipment, increase capacity, etc.).

This characterization of the current system can be extremely detailed. Although utilities need to collect the detailed information, evaluate needs and options, run the models and select preferred solutions, regulators can give clear guidance about the level of detail they expect to see included in the written IDP report.

B. Planned Retirements and Committed Future Resource Additions

The IDP should similarly describe any known or expected future asset changes on the distribution system and state the reason for the change. This should include planned retirements of existing assets and infrastructure projects which are already underway or to which the utility has already made financial commitments (such as the scheduled replacement of existing assets or additions to existing capacity), as well as planned deployments of metering or SCADA technologies. This portion of the IDP should reflect *decisions already made*; it is separate from the analysis of future needs and alternatives and the selection of preferred solutions. For example, if a *previous* IDP identified the need to add capacity to a substation, a contract was signed to add that capacity, but the additional capacity is not yet installed, that addition would be noted as a committed future resource addition in this section of the IDP.

C. Load and DER Forecast

The IDP report should include a load forecast (both MW and MWh) that covers every year of the planning horizon. Similarly, the IDP should include forecasts of expected annual additions of each type of DER on the distribution system. Load forecasts can then be combined with DER forecasts to develop net load forecasts. As discussed earlier, these forecasts will need to have spatial and temporal granularity. That is, they should identify the net demand expected at different nodes on the distribution system that are relevant for planning purposes (e.g., feeders or possibly substations) and may need to forecast net energy usage (measured in kWh or MWh) on annual, seasonal, monthly, or even daily timescales to enable proper evaluation of NWAs. The report should also describe the methods, data sources and models used to develop these forecasts.

Utilities and regulators are increasingly aware and concerned about the growing complexity of net load forecasting. New technologies, such as EVs and electric air source heat pumps, could significantly add to energy and peak demand requirements, while more efficient appliances or appliances with automated DR capabilities could significantly reduce those requirements. Flexible technologies like energy storage and "smart" EV charging equipment might have little or no impact on energy requirements but significantly change temporal load shapes. The confounding factor for planners is that customers, not the utilities themselves, ultimately control the rate at which DERs and energy end uses are deployed and the way they are used. This makes forecasting more challenging than ever before. Methodologies for forecasting DER adoption and its impact on load continue to evolve, such that the best available techniques at the time that an IDP is first developed may be superseded by the time the IDP is updated.[41] Commissions will want to consider this fact when deciding the frequency of required IDP updates.

Because forecasting is increasingly complex and uncertain, utilities and regulators now commonly use a range of forecast scenarios to inform planning processes. For example, multiple load forecasts could be developed using different assumptions about future EV and PV deployments in the service territory. Commissions should strongly consider giving guidance to utility planners on specific load and DER deployment scenarios to assess in the IDP. The IDP report should describe the assumptions underlying each scenario analyzed.

D. Hosting Capacity Analysis

The IDP report should provide a narrative description of any HCA performed. HCA is one of the foundational steps in an IDP process and a necessary predicate to identifying grid needs, proactively pursuing grid solutions, including NWAs, and optimizing the role of DERs on the grid.[42,43] An HCA is an analytical tool that can help states, utilities, developers and other stakeholders gain greater visibility into the current state of the distribution grid and its physical capacity to host DERs. In the context of an IDP, HCA is but one of several tools and approaches that should be considered and deployed to optimize DERs on the grid, including, but not limited

41 For today's planners, we offer some potentially helpful resources on forecast methodologies: (1) Mills, A. (2017). *Forecasting load on the distribution system with distributed energy resources*. Berkeley, CA: Lawrence Berkeley National Laboratory. Retrieved from: https://emp.lbl.gov/sites/default/files/11b._gmlc_mills_forecasting_dg_necpuc_training.pdf (2) Novotny, G. (2018). *A better way to forecast DER adoption*. Clean Power Research. Retrieved from: https://www.cleanpower.com/2018/forecast-der-adoption/ (3) IREC editors (2018). *Cornerstone for next generation grid activities: Forecasting DER growth*. New York: Interstate Renewable Energy Council. Retrieved from: https://irecusa.org/2018/02/cornerstone-for-next-generation-grid-activities-forecasting-der-growth-2/

42 Stanfield, S., Safdi, S., and Baldwin Auck, S. (2017, December). *Optimizing the grid: A regulator's guide to hosting capacity analyses for distributed energy resources,* p. 3. New York: Interstate Renewable Energy Council. Retrieved from: https://irecusa.org/publications/optimizing-the-grid-regulators-guide-to-hosting-capacity-analyses-for-distributed-energy-resources/.

43 U.S. DOE (2018.) *Integrated Distribution Planning: Utility Practices in Hosting Capacity Analysis and Locational Value Assessment*. Washington, DC: U.S. Department of Energy. Retrieved from: https://gridarchitecture.pnnl.gov/media/ICF_DOE_Utility_IDP_FINAL_July_2018.pdf.

to: revised DER and load forecasting methodologies, a locational valuation analysis, and a grid needs assessment to determine where DERs might function as cost-effective NWAs.[44]

The main factors that influence hosting capacity are: (1) the precise DER location, (2) the nature of the load curve on the feeder, (3) the feeder's design and physical and operational characteristics and (4) the characteristics of the DER technology.[45] The hosting capacity of any given feeder is a range of values, which depend on the specific location and type of resource in question. The results of the HCA are typically displayed visually in the form of a map, which color-codes feeders or line segments according to their hosting capacity range, published with accompanying datasets containing the more detailed underlying data. The maps and datasets together provide public access to hosting capacity values by location along with information on specific operational limits of the grid and other important grid characteristics, including areas on the grid that might be able to accommodate additional DERs without violating hosting capacity limitations.

Directing a utility to develop an HCA is an important first step in gaining a better understanding of the current conditions of the distribution grid, including any operational limits impacting the ability of DERs to interconnect to the grid. In addition to its function within IDP, HCA can also help provide the necessary transparency to streamline the interconnection process for DERs (see Section II.E.2 above) and help developers identify locations where there is more available capacity to host DERs or design DERs to fit within operational constraints. If deployed with intention, HCA can support more efficient and cost-effective choices about deploying DERs on the grid and derive the most economical grid solutions.

Several states are now requiring regulated utilities to deploy HCA. Among the MADRI jurisdictions, New Jersey is a leader in this area. In January 2019, the New Jersey Board of Public Utilities adopted rules for a Community Solar Energy Pilot Program that includes a requirement for investor-owned utilities to make hosting capacity maps publicly available and update them periodically.[46] California, Hawaii, Minnesota, New York and Nevada also require HCA, with most of these states working actively to integrate HCA into IDP.[47] Other states are in

44 Ibid., 13–14; and Homer, J., Cooke, A., Schwartz, L., Leventis, G., Flores-Espino, F., and Coddington, M. (2017, December). *State engagement in electric distribution system planning* [executive summary], pp. iii–v. Electricity Markets & Policy Group. Berkeley, CA: Lawrence Berkeley National Laboratory. Retrieved from: https://emp.lbl.gov/publications/state-engagement-electric.

45 For helpful references, refer to two publicly available EPRI publications: EPRI (2018, January 31). *Impact factors, methods, and considerations for calculating and applying hosting capacity.* Palo Alto, CA: Electric Power Research Institute. Retrieved from: https://www.epri.com/#/pages/product/000000003002011009/?lang=en; and EPRI (2015, December 31). *Integration of hosting capacity analysis into distribution planning tools*. Retrieved from: https://www.epri.com/#/pages/product/3002005793/?lang=en-US.

46 New Jersey Administrative Code, § 14:8-9.9(f).

47 Homer et al., 2017, iv; and Nevada Public Service Commission (2017). *Investigation and rulemaking to implement Senate Bill 146.* Docket No. 17-08022; and New York Joint Utilities (2016, November 1). *Supplemental distributed system implementation plan*, p. 49. Case No. 16-M-0411: In the matter of distributed system implementation plans. Central Hudson, Con Edison, NYSEG, National Grid, O&R, and RG&E. Retrieved from: https://jointutilitiesofny.org/wp-content/uploads/2016/10/3A80BFC9-CBD4-4DFD-AE62-831271013816.pdf.

the early stages of exploring HCA, such as Colorado, Maryland and the District of Columbia.[48] Additionally, several utilities are deploying HCA outside the context of more formal state requirements,[49] including Commonwealth Edison (ComEd) in Illinois[50] and Pepco Holdings, Inc.,[51] which owns several utilities in other MADRI jurisdictions.

It is important to note that there are multiple HCA methodologies, each with different capabilities and limitations. HCA model providers continue to refine their tools, and models and methodologies continue to evolve with time and experience. As such, one of the key choices state regulators will need to make at the outset of an HCA process is deciding on which HCA methodology to adopt. Whether just beginning to consider or already actively exploring HCA, regulators and utilities can take steps to understand and gain familiarity with the different HCA methodologies, their functions, their capabilities and their limitations (leveraging the learnings from other states and utilities that are further along in their adoption and implementation of HCA).

Regulators overseeing an HCA should consider establishing a transparent public stakeholder process at the outset to help develop the HCA use cases and garner buy-in for the objectives of the HCA. Regulators can also provide clear and explicit guidelines to the utilities for HCA development and deployment to ensure alignment with those objectives and ensure the HCA will meet its stated purposes. Such foundational work prior to development and implementation of the HCA will help ensure the tool is both used and useful and that the time and resources committed by all involved stakeholders (including regulators) are efficiently spent. To this end, the following questions and considerations can be useful to ask and answer at the outset of an HCA effort:

- What process will the commission establish to allow for stakeholder input in the HCA development process (i.e., a series of workshops, meetings, a workgroup, written comments, etc.)?
- Who will be allowed to participate in the process?
- Will there be a facilitator for the process and how will he or she ensure effective and neutral reporting of stakeholder input and outcomes?
- What is the timeline for the process?

48 See Colorado Public Utilities Commission (2018). Review Of ERP, RES and Integration Rules. Docket No. 17M-0694E; Maryland Public Service Commission (2016, September 26*). In the matter of transforming Maryland's electric distribution systems to ensure that electric service is customer-centered, affordable, reliable and environmentally sustainable in Maryland*. Docket No. PC 44. Retrieved from: https://www.psc.state.md.us/wp-content/uploads/PC-44-Notice-Transforming-Marylands-Electric-Distribution-System.pdf; and Public Service Commission of the District of Columbia Docket (2019, May 1). In the matter of the investigation into modernizing the energy delivery system for increased sustainability [letter]. Docket No. FC1130-433. Filed by District of Columbia Government by Office of the Attorney General. Retrieved from: https://edocket.dcpsc.org/public/search/casenumber/fc1130https://edocket.dcpsc.org/public/search/casenumber/fc1130.

49 Stanfield et al., 2017, 41–42.

50 ComEd (undated). ComEd Hosting Capacity [web page]. Chicago, IL: Commonwealth Edison Company. Retrieved from: http://comed.maps.arcgis.com/apps/webappviewer/index.html?id=e1844512fecb4393b39d9e3068cfbd2f.

51 Pepco (undated). Hosting capacity map [web page]. Washington, DC: Potomac Electric Power Company. Retrieved from: https://www.pepco.com/SmartEnergy/MyGreenPowerConnection/Pages/HostingCapacityMap.aspx.

- How often will stakeholders be expected to meet to produce each deliverable, and in which stages of the HCA development and implementation will they be involved?
- What are the specified deliverables from the utilities and other stakeholders throughout the process?
- What protocol is needed to allow for nonutility stakeholders to review and provide input on the HCA tool development?
- How will transparency of data, assumptions and methodologies be assured for all participating stakeholders? If there are data privacy and/or confidentiality concerns, those should be discussed at the outset to identify workable solutions to allow stakeholder access to information as appropriate.

Whether and to what extent an HCA can be used to develop an IDP, inform short- or long-term grid investments and/or support the streamlined integration of DERs is directly connected to several factors, including: the defined use case(s) for HCA, the underlying methodology to support those use cases, and the assumptions used to run the HCA model. As noted, regulators and utilities should carefully consider and articulate their goals for the HCA and define the use cases at the outset of any formal regulatory effort. There are two principal applications, or use cases, for an HCA: (1) assist with and support the streamlined interconnection of DERs on the distribution grid; and (2) enable more robust distribution system planning efforts that ensure DERs are incorporated and reflected in future grid plans and investments. A third, complementary function of an HCA could be to inform pricing mechanisms for DERs based on separate analyses to assess the benefits of DERs based on their physical location on the grid and their performance characteristics.[52] Regulators overseeing and guiding IDP efforts should be aware of and familiar with the distinctions and trade-offs among HCA methodologies and models. Different HCA methodologies can result in different hosting capacity values due to different technical assumptions built into the models, and the methodological choices in an HCA can significantly impact whether the results are sufficiently reliable and informative for the intended use cases, whether for an IDP, for interconnection or to inform other grid-related investments. Commencing an HCA process without clear uses and goals creates a real risk of duplicative expenditures by utilities, which are ultimately borne by ratepayers. By clearly articulating the goals of the HCA planning use case, regulators can ensure that an effective HCA tool is developed. To help inform this understanding, regulators, with stakeholder input, should consider addressing the following questions at the beginning of an HCA process:

- What state policy goals, if any, will the HCA support?
- What are the use cases for the HCA, and how should they be defined?
- How will it be ensured that the HCA methodology selected by a utility can support the defined use cases?
- What are the limitations of the different HCA methodologies?
- What are the implementation costs of the different HCA methodologies?
- If there are two (or more) defined use cases (e.g., IDP and Interconnection), can the same HCA methodology and/or model be used to support both?

[52] Stanfield et al., 2017, 5–6.

- Will the HCA be developed in phases? If so, what will each phase address?[53]
- If developed in phases, how will the HCA be scaled over time? That is: Will HCA be performed across the entire distribution system at the outset or only on those feeders with the greatest projected DER demand? Will it be performed on single-phase feeders in addition to three-phase feeders?
- What have other states adopted and what has been their experience?

The accuracy of the HCA data, how HCA information is displayed and shared, and the transparency of the data and the underlying methodology will all impact its usefulness for its defined use case(s). In the context of IDP, for example, the HCA may need to be run on the entire distribution system under different scenarios about assumed DER growth across *varying time horizons*. Regulators might also consider how frequently the HCA needs to be run to ensure that results are sufficiently up to date, and the level of accuracy is necessary to meet the planning use case goals. Regulators may want to request the following information from the utility to ensure the HCA can be as useful as possible and that the tool can be validated, adapted and improved over time:

- How granular is the HCA and to what extent will the published maps and data files reflect that granularity (i.e., down to the line section and node level)?
- How many load hours or nodes are evaluated?
- What extent of the distribution system will be covered by the HCA (i.e., the entire system, high-priority portions, incremental expansion over time, etc.)?[54]
- What types of DERs will be modeled (i.e., DG, energy storage, EVs, microgrids or all DERs)?
- Is the HCA technology neutral?[55]
- How will HCA data be published and displayed on system maps?
    - What kind of color-coding will be required on system maps?

[53] See Nevada Public Service Commission, 2017. Alternative Rule NAC 704.948X(3) would require a "phased" process for developing the hosting capacity analysis: Nevada Energy (NVE) would file an initial analysis using thermal and voltage criteria for as many feeders on the system as possible by April 1, 2019, followed by a second analysis for all feeders in the system, adding protection, reliability and safety criteria, filed by June 1, 2021. Between the initial and second phases, NVE would engage with participants to identify pilot programs and projects to test the initial methodology and share the findings from the implementation of any pilot programs and projects with participants. Additionally, following each filing required by Alternative Rule NAC 704.948X, the commission would set forth a process for stakeholder comment pursuant to public notice. See also New York Joint Utilities, 2016, 49. The New York utilities proposed a four-stage HCA road map, with each subsequent stage increasing in effectiveness, complexity and data requirements.

[54] See Stanfield et al., 2017, 21: "The California utilities, for instance, mapped all three-phase lines in the test areas and are exploring expanding the HCA to single-phase lines and reserving for future analysis interactions with the transmission system (such iteration of the tool is a good example of how HCA efforts can be phased over time to become more sophisticated and robust). Xcel Energy in Minnesota has proposed excluding feeders serving low voltage networks in downtown Minneapolis and St. Paul areas, which have not been previously modeled."

[55] For example, at the direction of the California Public Utilities Commission, the utilities have made an "ICA translator" available to users to determine the hosting capacity values for different types of DERs. See CPUC, 2016, 16. New York and Minnesota are just focusing on solar of a certain scale in their initial analysis: New York Public Service Commission, 2017, March 9; Xcel, 2015, 3–4, 6 (focusing HCA analysis on small-scale DG technologies); Minnesota PUC, 2017, 9, 11 (explaining that "energy storage load characteristics were excluded from [Xcel's HCA] analysis" and excluding DR and EE technologies from Xcel's definition of DER).

    - What level of granularity will the maps reflect (e.g., hosting capacity data for each line section or only at the feeder level)?
    - Will data display boxes be required on the maps, and if so, what information should utilities be required to display? For example: An HCA value for each power system limitation or the overall HCA at a point? Existing and queued generation? The feeder load profile?
    - What kind of DER generation profile will the user be able to select?
    - Will hosting capacity maps be provided for both generation and load?
- Should any or all of the underlying data be made publicly accessible?
    - If so, how will the underlying data be shared (e.g., through downloadable and sortable data files or in a machine queryable format)?
    - If so, what underlying data will be provided (e.g., each operational constraint analyzed or only the limiting constraint) and at what level of granularity?
- Are there privacy, cyber or physical security considerations to consider when sharing HCA data? If so, what are the concerns and how can they be addressed and managed?
- How frequently will the HCA results be updated and published (i.e., real time, weekly, monthly, annually, etc.)?[56]
- How will HCA results be validated over time?

Lastly, to the extent regulators are overseeing HCA development across multiple utilities, efforts to ensure consistency in approaches and methodologies among all regulated utilities within the regulatory jurisdiction is likely to help simplify and streamline the implementation and oversight process while also ensuring a more consistent and efficient utilization of the tool. If utilities are at different stages in their ability to adopt and deploy HCA, regulators can help establish clear guidelines and direction to ensure consistency in approaches and models over time.

E. Needs Assessment and Risk Analysis

The IDP report will need to summarize both the methods and the results of the needs assessment step. This is the step where the current and planned capabilities of the distribution system are assessed to see if they can adequately serve the forecasted net load. Within the needs assessment portion of the report, the utility should first explain the criteria used to assess reliability and risk and the modeling tools and methods used to identify future system needs. The IDP report should then summarize the results of the assessment, beginning with the identified needs. Finally, the IDP report should describe the criteria used to prioritize grid investments and the results of that prioritization exercise. These three elements of the needs assessment are described below.

1. Reliability/Risk Criteria and Modeling Tools/Methods

Reliability at the distribution system level is commonly measured based on the average duration (system average interruption duration index or SAIDI) and frequency (system average interruption frequency index or SAIFI) of interruptions. Many utilities have established goals for these metrics or have been given targets (sometimes associated with performance incentives) by

[56] For planning purposes, less frequent updating may be required if scenarios are only needed on a periodic basis (such as annually or as appropriate). See Stanfield et al., 2017, 20.

regulators. In those cases, the goals or targets should be explained in the IDP report with a clear explanation of how the metric is defined and applied to the planning process.

Resource adequacy metrics that are commonly assessed for the bulk power system, such as loss of load expectation, are not typically applied at the distribution system level. Instead, it is common to compare the capacity of various distribution system components to their historical utilization and expected maximum future loadings to identify overload conditions. The system will, of course, be assessed under normal, intact conditions, but planners may also assess how the system holds up under N-1 contingencies,[57] such as the unscheduled loss of a single feeder. In any event, the IDP report should explain the criteria that are used by planners to determine if the system has adequate capacity and capabilities to reliably meet projected customer needs. It should also explain the components of the system (e.g., circuits or substations) to which each criterion is applied.

Although reliability metrics like SAIDI and SAIFI will not directly factor into the assessment of system capacity, utilities that are falling short of their reliability goals may adopt a more aggressive approach to planning for reliability improvements than utilities that have already reached their goals.

The IDP report should also clearly explain the modeling tools (i.e., software) and modeling methods (including a description of contingencies and scenarios evaluated) that were used to assess system adequacy and performance with respect to the established criteria and goals.

2. Identification of Constraints on the Distribution Grid

There is a complex interplay among variables that establishes a maximum load-carrying capacity for overhead power lines. Identifying constraints on the existing distribution system is an important part of the IDP needs assessment. A constraint, in this context, is any condition or consideration that may limit the capability of a distribution system component to serve load. Constraints can be related to equipment thermal ratings, power quality criteria that must be satisfied, reliability criteria, worker safety requirements or the need for system protection. For example, for reliability and safety reasons, there is a minimum distance that distribution lines must be away from the ground, structures and vehicles. The temperature of a conductor is determined by a combination of ambient air temperature, conductor material and size and current flow. The length of a suspended conductor increases as its temperature increases, which means that the low point of the line falls closer to trees, structures, and so on. In most of the United States, the amount of line sag is greatest on very hot summer afternoons and early evenings when lines are fully loaded. This phenomenon poses a constraint on power-carrying capacity of overhead circuits, where each crossing of a roadway must be evaluated. There is no policy imperative for regulators to specify detailed constraints at this level; utilities have adopted their own over the years and used them to achieve the higher-level goals already specified by regulators (e.g., SAIDI and SAIFI targets, safety requirements).

[57] An "N-1 contingency" examines the expected impacts on resource adequacy and power quality if one key component of the system becomes unavailable due to an unscheduled/forced outage – i.e., the normal system (N) minus 1 component.

There are basically five reasons why grid components need replacement over time:

i. Breakage or damage — A common reason for early replacement of power-line poles is breakage caused by vehicle impact or excessive mechanical loading caused by ice buildup on conductors, extreme wind velocity and/or wind-propelled tree limbs and debris impacting poles or conductors. Beyond these causes, any component may be subject to premature failure simply because expected life is a statistical value and a few units in the population will have a significantly longer or shorter time to failure.

ii. Age-related degradation — As the various components of the grid age with time, they are subjected to varying temperatures, ultraviolet radiation, wind loadings, vibration and operating cycles, all of which cause an inevitable degradation of some of the physical attributes of the components. The effects of this age-related degradation are one reason that components that require properly functioning electrical insulation, such as transformers and insulated conductors, need to be periodically replaced.

iii. Increase in the served electrical load — The power-delivery capability of each circuit is designed with a maximum load delivery value under expected ambient conditions (i.e., outdoor temperature, which has a significant influence on load), as determined by the circuit-by-circuit load forecast analysis that utilities typically perform each year. However, several years after some circuits are built and placed in operation, it is not unusual for the load forecast to show that the growth rate is expected to have a large increase three to six years in the future because a new housing development and/or new large buildings are now going to be built; plans that were not known at the time(s) when the earlier forecasts were prepared. The new forecast shows that the new peak load will reach or exceed the power delivery capacity of one or more circuits, which means that the utility should plan to replace some of the grid components with larger power-delivery ratings. In some cases, when the new forecasts for several circuits in a region of the grid show greater loads in the future, the utility may decide it is time to build a new substation to serve the region.

iv. Exogenous factors, such as trends in climate change or new security threats — The increase in the frequency of severe storms and hurricanes, rising sea levels, wildfires and new security threats have resulted in the need to harden or relocate existing grid assets to establish a more acceptable level of resiliency. In the case of substations, solutions include installing additional intrusion detectors and constructing concrete and steel barriers to protect vulnerable grid assets from bullets and wind-borne debris and surrounding them with berms to prevent flooding, backed by pumps to remove any surface water higher than a predetermined safe level. To maintain uninterrupted power delivery, relocation of power lines and smaller transformers is accomplished by first constructing new lines and installing new transformers and associated items at higher elevations, and then removing the existing, more vulnerable circuit components. This category also includes accidents, including construction and vehicle accidents damaging or destroying distribution equipment.

v. Significant technical enhancements available in new equipment — Occasionally, studies will demonstrate that premature replacement of existing grid components with new versions with added features and technological advances will result in cost savings. A prime example is the replacement of power meters that record cumulative kWh and peak kW over a period of time with AMI systems, which store kWh readings over successive brief intervals of time, and then automatically transmit the stored data to a central digital warehouse storage facility for later analysis and computation of monthly bills to be sent to end-use customers.

The most common constraints are: (1) the inherent peak-load delivery limit, as determined by the capacity of a specific transformer or power line, and (2) the likelihood of damage to a power line or supporting structure (e.g., pole broken by vehicle impact or an extreme weather event).

3. Prioritization of Needs

The need for an upgrade to the peak-load delivery capability of a circuit or larger portion of the grid is a routine occurrence that cannot be ignored. However, some upgrades can be deferred in a way that produces long-term cost savings. On the other hand, damage to the grid caused by severe weather events may trigger the need for immediate remedial action. The point is that even necessary upgrades will vary in terms of their urgency and priority for action.

The IDP report should clearly describe the criteria used by planners to identify or rank the highest priority needs, and then document the results of this prioritization exercise. The result will be a transparent explanation and categorization of the distribution system needs that require immediate action, near-term action or longer-term action.

F. Evaluation of Options for Meeting Forecasted Needs

In a traditional distribution planning process, virtually every need would be satisfied by finding the least costly, utility-owned transmission or distribution infrastructure investment that solved each problem (e.g., a new primary or secondary line, a new transformer or a new substation, etc.). In an IDP process, those traditional options are supplemented with equal consideration of NWAs, including targeted applications of energy storage, DG, DR, managed EV charging, microgrids and EE. Changes in rate design that affect peak demand should also be considered.

The IDP report should describe the assumed capabilities and costs of each option category considered. The IDP report should describe the assumed capabilities and costs of each option category considered. Because the adoption of customer-owned or third-party-owned DERs is not unlimited and not controlled by utilities, planners may need to assess the amount of DERs that might reasonably be deployed in time to meet identified needs assuming utilities apply their best efforts to encourage and incentivize such adoption. EE potential studies, for example, could be used to estimate how much EE could be procured in a targeted area over a given timeframe. The planners may need to solicit data or bids from vendors to accurately characterize the availability, costs and capabilities of DERs.

Ultimately, the IDP report should identify the preferred solution and compare the expected cost of that solution to the expected cost of other options that were deemed technically capable of meeting the need. If risk or other criteria factor into the selection of the preferred solution, those criteria should also be included in the comparison. In some cases, the preferred solution may be a combination of resources — for example, a combination of targeted EE, targeted DR and traditional distribution infrastructure (but with the infrastructure assets sized smaller and costing less than if there were no EE or DR). And finally, if the IDP process used a range of assumed values or assessed multiple scenarios, the least costly option might vary from one scenario to the next or vary depending on which assumptions are used. In such cases, the report should explain how the preferred solution was selected.

G. Action Plan

An IDP should include an *action plan,* which is the culmination of the process in which numerous scenarios are considered to develop the best options for meeting forecasted needs. The purpose of an action plan is to set forth the actions that need to be implemented in the near term, as in the first four or five years of the planning period. The action plan is then the guiding document for the commission, the utility and the stakeholders to rely upon when making and evaluating planning and investment decisions for the distribution system.[58]

The action plan should include the plans for soliciting the deployment of DERs, as well as plans for permitting, constructing, preparing required reports and other significant activities where replacement, upgrades or expansion of utility infrastructure has been identified as the best option. Plans for the retirement or retrofit of existing major equipment should also be identified. The action plan should include a timeline that establishes the sequence of events for each action to be taken. Further, the action plan should include, where appropriate, plans to solicit competitive bids through a request for proposal process. In this manner, the commission can conveniently track the utility's progress in meeting the expectations of the IDP.

The commission will typically rule on the action plan, with the options to approve, disapprove or modify the plan, which then becomes the guiding road map until the next IDP and action plan are approved. Commissions may also want to consider allowing some flexibility for changed circumstances depending on the length of time between approved IDP action plans; however, the commission will want to retain the authority to review and approve any major changes.

H. Summary of Stakeholder Engagement

The IDP report should explain the roles that stakeholders played in developing the plan. This should include at a minimum identifying the involved persons and their organizational affiliations, summarizing any stakeholder meetings that were convened and noting any opportunities for comment that were afforded outside stakeholder meetings. The term *stakeholder* should be broadly construed here to include experts from outside the utility who may have been engaged as expert advisors or who may have provided data or data analysis.

[58] The elements of an approved action plan would likely become inputs in the utility's next rate case, or in a separate proceeding where a capital budget is approved (such as a grid modernization proceeding).

V. CHALLENGES FOR DEVELOPING AND IMPLEMENTING AN IDP

The process of developing an IDP raises new challenges for everyone involved. In this section, we examine some of the key challenges for utility commissions, utilities, customers and DER providers.

A. Commissions

The utility industry is facing a learning curve as new technology and changing societal priorities redefine the electrical grid. The issues are pervasive and complex. They include, for example, historical regulations and commission practice, utility priorities and legacy systems, customer knowledge and benefits and optimizing and valuing the DERs themselves. This next section will highlight some of the issues that utility commissions need to address in developing and implementing an effective IDP.

Commissions may need to consider different approaches than their traditional regulations and practices. Most have not had experience with granular and detailed planning processes for grid investments at the distribution level. Historical tariffs, rules and practices will have to change to align costs with prices. The need for an efficient and effective system to optimize DER deployment in an empirical and long-term sustainable manner grows as technology advances, societal goals shift and hard and soft DER costs decrease, resulting in resources becoming less centralized. It is imperative that a commission understands the goals it is trying to achieve and how it wants to try to achieve them and works to reduce the challenges and barriers that might harm its progress toward those goals.

Commissions will need to open what has traditionally been a rather opaque process to increase the transparency and efficiency of the distribution grid. Investments and methodologies that led to the current grid will be examined at a much closer level than before. Commissions can make sure this transition is orderly, leads to benefits for the grid and is not retroactively punitive.

Some of the biggest challenges for Commissions will relate to staffing, retail rate design and DER compensation, state rules that may prohibit or inhibit DER deployment, and data transparency and ownership. Each of these topics is addressed below.

1. Staffing

Commissions will want to make sure they have the right staff capacity and expertise to oversee the IPD planning process and utility implementation of the IDP. As covered above, the new elements that make up developing and implementing IDP are varied. These elements require new expertise and add on new considerations for traditional areas. For example, IDPs and grid modernization add new elements in engineering, operations, information technology, communications, short- and long-term investments, customer education and rate design, among other areas. The work is more varied and complex than simply expanding any current work the commission does to ensure a reliable distribution grid, to calculate the grid's revenue requirement of embedded (or sometimes marginal) costs, or to design retail rates. If necessary, gaps in capacity or technical expertise could be filled by contracting with qualified impartial experts.

2. Retail Rate Design and DER Compensation

IDP planning should incorporate least-cost options, and if a DER alternative will save ratepayer money over a traditional utility wires approach, then the DER alternative ought to be adopted. Thus, the challenge of developing a good IDP is closely tied to the challenge of optimizing DER deployment. If DERs are deployed in the right amounts and the right places, they can contribute to the most reliable, least-cost distribution system. If investment in DERs is too high (e.g., because they receive compensation in excess of their value to the grid) or too low (e.g., because they are not used to defer more costly system upgrades), system costs will increase. This is true of all types of resources, including traditional utility infrastructure investments, but the difference is that customers – not utilities -- determine when, where, and in what amounts to deploy DERs. And those customer decisions are heavily influenced by decisions that utility commissions make about retail rate design and DER compensation.

Retail rate design is a complex and challenging subject that is at the core of what utility commissions do. However, most of the long-held principles of retail rate design that have guided Commission decisions for decades were developed before the advent of affordable DERs. To get the right mix of resources installed on the grid, Commissions may need to reconsider their current approach to retail rate design and DER compensation. This would most likely occur outside of an IDP proceeding in a general rate case or a separate rate design proceeding. Given the complexity of this topic, additional guidance is presented in Appendix 2.

3. State Rules that May Prohibit or Inhibit DER Deployment

Existing administrative rules should be examined to see if any of them are unduly working against optimal DER deployment. Commissions can examine the regulatory environment in which DERs will be deployed to make sure that current rules do not unduly hamper DER growth at sub-optimal levels. For instance, the existing statutory authority, or existing commission rules, may represent an outright prohibition to some business and ownership models that would lead to beneficial DER deployment.[59] Third-party ownership of rooftop PV is one example of the many innovative ways to deploy DER for customers who may not be able to finance or purchase a PV system outright. Some jurisdictions may not allow these arrangements or may even require utility ownership and control of a PV system. Another indicative example would be legacy rules that treat residential customers with small rooftop PV systems the same as large and sophisticated merchant generators, for example with respect to interconnection studies or the need to obtain insurance against damages caused to the grid.

Interconnection rules are another example of an area in which customers may face long delays, confusing requirements or high costs and fees. Experience in other jurisdictions, such as California and Hawaii, have shown that at low deployment levels small systems proposed for distribution feeder lines with ample capacity should have easy and quick screens that allow them

[59] Many states do not allow non-utility third parties to bid aggregations of DR resources within their state directly into organized wholesale markets, but this restriction does not currently exist in any of the MADRI jurisdictions.

to forego more extensive and expensive interconnection studies. It is also beneficial to make sure customers have general information about project feasibility before involving the utility or third parties, for example through online hosting capacity maps that allow them to see where DERs are needed and where additional capacity investments might be required in order to accommodate DERs.

Commissions can strive to ensure their regulations address modern technology while also staying flexible enough for future changes and third-party business models. Technology-specific rules, such as requirements for smart inverters or interoperability standards, can help steer resources in directions that can provide more benefits and options for the customers and the grid.

Lastly, regulations regarding customer electrical data oftentimes have not caught up with the advancements in technology and need updating. Insufficient data, rules and protocols, as well as insufficient utility operational capabilities, can be a large and complex barrier to DER deployment. As technology and communications advance, the data produced concerning a customer's energy usage will increase in granularity and volume. From new AMI, utilities are now interacting with interval data broken out into smaller and smaller durations. Partially because of this vast expansion of the volume of data, many utilities have looked to outside vendors, usually so-called cloud providers, to help store and analyze all this new data.

In some jurisdictions, the commission reserves the right to include additional questions on related issues that may not be expressly addressed in an IRP. In a similar vein, to the extent that an IDP does not cover with sufficient detail the topics addressed in this section, the commission could reserve the right in its rules to require that this information be provided through a series of commission-issued questions.

4. Data Transparency and Ownership

It is crucial that the privacy of customer-specific data be protected with modern cyber security best practices. Commissions generally want to ensure utilities know what is expected of them, are following the latest best practices, and allow for adequate recovery of any associated costs. This should be done using industry standards. The commission's need to know what systems the utility has put in place for which cost recovery is requested should be balanced with any concerns about the commission knowing too much of the specifics.

Many advocates believe that customers should "own" the data that the utility infrastructure or third parties produce on their behalf or based on their metered usage. But putting aside any legal questions about data ownership, as commissions and utilities struggle to address this complicated topic in a cyber-security-sensitive environment, it is important to ensure that customers have adequate privacy protections. It is equally important to determine what types of data customers should be able to easily access and to mitigate any possible risks in providing that data to them.

This includes a safe way to share customer-identifying data with third parties that wish to market and price potential services to those customers. This should be achieved in a process that is as seamless and easy as possible, while still protecting customers. Many jurisdictions use Green

Button Connect My Data.[60] Some are also looking to include other standards, such as OpenID used by banks. Data privacy and security best practices must balance the utilities' requirements for confidentiality and security with the customers' desire for accessibility and transparency.

There also seems to be value in making aggregated and anonymous data available, perhaps with a small processing fee, to researchers and other interested parties. This allows independent analysis of the impacts of various products on bills or for the identification of savings opportunities for certain load types. The data is usually made anonymous by stripping out any customer-identifying information and aggregating usage by area so that any one customer's usage cannot be disaggregated. In any event, no customer-specific information should be shared without the customer's explicit consent.

Commissions have difficult changes ahead but forethought, empirical analysis and enough time for an orderly transition will greatly help with these challenges.

B. Utilities

DERs interact with the grid in ways that were not imagined when the system was originally built, and utilities consequently face a variety of new challenges that affect their ability to plan for a reliable and cost-effective distribution system. This section discusses some potential challenges facing utilities and briefly reviews a few possible approaches to addressing them. MADRI states will undoubtedly need to assess the relative importance of these challenges to their circumstances and how to approach any potential solutions.

1. Visibility and Data Quality

One major challenge for utilities is that operation of the electrical distribution grid increases in complexity as DERs are deployed. For instance, the utilities have not historically had to incorporate DG's two-way power flows coming from behind their residential meters. Maintaining safe and reliable grid operations now requires more data than ever before.

As regulators and utilities endeavor to develop an IDP, they may need to address whether there are limitations in the data available to planners and/or in the ability to process existing data to develop the necessary grid information tools to inform the IDP. As the IDP process outlined above indicates, planners need accurate information about current DER deployments to:

- Properly assess current system conditions, hosting capacity and locational values;
- Forecast future supply, demand and system constraints; and
- Assess potential solutions to forecasted system needs.

The term of art used by both planners and system operators is *visibility*. Having visibility means having sufficiently accurate data about the locations, capabilities and status of DERs to enable sound planning and system operations. A lack of visibility can lead to bad infrastructure investment decisions, inefficient system operations and reliability problems.

[60] For more information on the Green Button Program, go to http://www.greenbuttondata.org/.

Although there are not likely to be actual physical constraints on the grid that would prevent a utility from deploying an IDP, the existing grid infrastructure may limit the level of granularity and sophistication of the analyses. The following are a few considerations to keep in mind:

- **Smart Meters or AMI:** Deployment of AMI to all customers is useful for gathering more granular customer data, more precise load forecasts and other data that can help inform future grid planning. This does not mean that AMI deployment is a prerequisite for IDP. Using existing metering data as a starting point can help to identify information gaps and opportunities to learn from other utilities that have deployed AMI. Though an important consideration, metering infrastructure should not be an impediment to getting started on an IDP process.[61]
- **Interconnection data and DER databases:** Frequent tracking of interconnection applications for DG and storage assets and databases of existing DER on the grid (including EVs) can provide an important starting point for developing a clearer understanding of the grid's current conditions and anticipated future conditions as they relate to DER deployment. Not all utilities track, report and/or maintain updated interconnection data, though arguably this is part of the existing interconnection review process and thus would not be too difficult to develop in a sharable publicly transparent format. DER databases can also be scrubbed of proprietary customer data and used to provide information about existing grid conditions and DER adoption trends. Processing this data for the purposes of an IDP will require consistency over time in how the data is collected, tracked and reported.
- **Advanced inverters:** The adoption of the Institute of Electrical and Electronics Engineers (IEEE) 1547-2018 standards will result in a number of changes to DER infrastructure, including the inverter functionalities, to allow for near real-time responsiveness to grid conditions. IEEE 1547-2018 will also eventually result in the adoption of new communications and controls capabilities to enable the two-way flow of information between utilities and DER customers. Though widespread implementation of this standard is still a few years off (see Appendix 3), these forthcoming changes should be considered in the development of any IDP and revisited once IEEE 1547-2018 is fully rolled out with compliant technologies available in the marketplace.[62] PJM is planning to release a document providing guidance on the ride-through and trip aspects of the IEEE 1547-2018 standard.
- **Customer preferences:** Utility customer surveys regarding DER adoption can be useful to inform IDP, while keeping in mind that customer preferences are likely to shift over time as market conditions and other economic factors change and customers' actions do not always mirror their stated preferences. Consistent and regular surveys can be useful in informing an IDP effort (alternatively, foregoing such investigations may limit the accuracy of an IDP).

[61] One of the earliest accomplishments of MADRI was the creation in 2005 of an AMI toolbox, which was significantly updated in 2008. The AMI toolbox compiled reports and studies as well as other web-based resources that were accumulated by MADRI support staff as they evaluated AMI strategy options. The toolbox is archived on the MADRI website at: http://www.madrionline.org/resources/ami-toolbox/.

[62] Lydic, B. (2018, July 23). Smart inverter update: New IEEE 1547 standards and state implementation efforts [blog]. New York: Interstate Renewable Energy Council. Retrieved from: https://irecusa.org/2018/07/smart-inverter-update-new-ieee-1547-standards-and-state-implementation-efforts/.

- **DER and load forecasting methodologies:** The future growth of DERs on the electricity grid does not have historical precedent, and utilities and regulators will need to account for this fact as they adjust how they plan for and invest in their electricity systems over the long term. Ideally, accurate DER forecasts will help utilities and stakeholders answer related questions: When will DER growth occur over time? Where on the grid will that growth occur? How will these new DERs operate? What impact will this growth have on future load forecasts? These and other considerations are relevant to the effectiveness and accuracy of DER and load forecasts in the context of IDP and grid investments, and they can be limiting factors if not addressed proactively.[63]
- **Understanding the different impacts of DER technologies on customer load:** The distinct performance characteristics and related consumer behaviors associated with DERs are extremely relevant to DER and load forecasting and thus IDP. To obtain this data, utilities will need AMI (for customers with DERs, if not necessarily all customers), or they will need to collaborate with DER customers and third-party providers to monitor and gain insight into the variances in load behavior over time due to the adoption of DERs. Absence of this information may hinder efforts to develop more robust IDPs if not addressed.

2. Lost Revenues (the Throughput Incentive)

Under traditional cost-of-service regulation (COSR), the retail rates charged by an investor-owned utility are approved by a utility commission in a rate case. The approved rates are designed to recover the utility's fixed and variable costs of service, including an authorized rate of return for its shareholders, based on detailed assumptions about consumer demand for electricity and the costs of serving that demand.

Retail rates for large commercial and industrial customers have traditionally consisted of three parts: a fixed monthly customer charge (in dollars per month), a demand charge (in dollars per kW of maximum demand)[64] and an energy charge (in cents per kWh consumed). The utility recovers most of its fixed costs of serving those customers through demand charges and most of its variable costs through energy charges. Rates for residential and small commercial customers, in contrast, have traditionally consisted of just two parts: a customer charge and an energy charge. For those customers, a utility using the traditional rate design recovers its fixed and variable costs of service almost entirely through energy charges — "one kWh at a time." Thus, a tiny portion of the utility's fixed costs is recovered in each kWh delivered.

In between rate cases, if the utility's customers purchase fewer kWh or reduce their peak demand in kW below what was assumed when rates were approved, the utility may fail to recover its full cost of service. Variable costs will go down with reduced sales, but fixed costs will not, and the retail rates were designed to recover fixed costs through variable demand and energy charges.

[63] McConnell, E., and Johnson, A. (2018). *Cornerstone for next generation grid activities forecasting DER growth*. New York: Interstate Renewable Energy Council. Retrieved from: https://irecusa.org/2018/02/cornerstone-for-next-generation-grid-activities-forecasting-der-growth/.

[64] The billing determinant for demand charges varies from one utility to the next. The charge is most commonly based on the customer's highest average demand over a very short time interval (e.g., 15 minutes) at any time during the monthly billing cycle.

Conversely, if the utility sells more kWh or customers raise their peak demand higher than assumed, the utility may collect revenues greater than its cost of service and exceed its authorized rate of return. This is the essence of the throughput incentive: all else being equal, utilities under traditional COSR have an inherent incentive to maximize throughput, that is, kW and kWh sales.

The throughput incentive can be particularly powerful for restructured utilities, such as those in the MADRI footprint that are responsible for energy delivery but not energy supply. Most of the costs of *delivering* energy (i.e., the costs of maintaining an adequate distribution system) are fixed in the short term (between rate cases).

The throughput incentive can be a challenge for utilities implementing IDP because deployment of DERs can reduce energy deliveries or peak customer demand, resulting in lost revenues and decreased profits. This has been well documented, especially with respect to the impacts of EE measures.[65] Fortunately, practical solutions for addressing the throughput incentive exist.

One option is to use smart rate designs and fair DER compensation mechanisms, as detailed in Appendix 2. Rate designs and compensation mechanisms that send appropriate price signals to customers about system costs and cost drivers should minimize lost revenue problems.

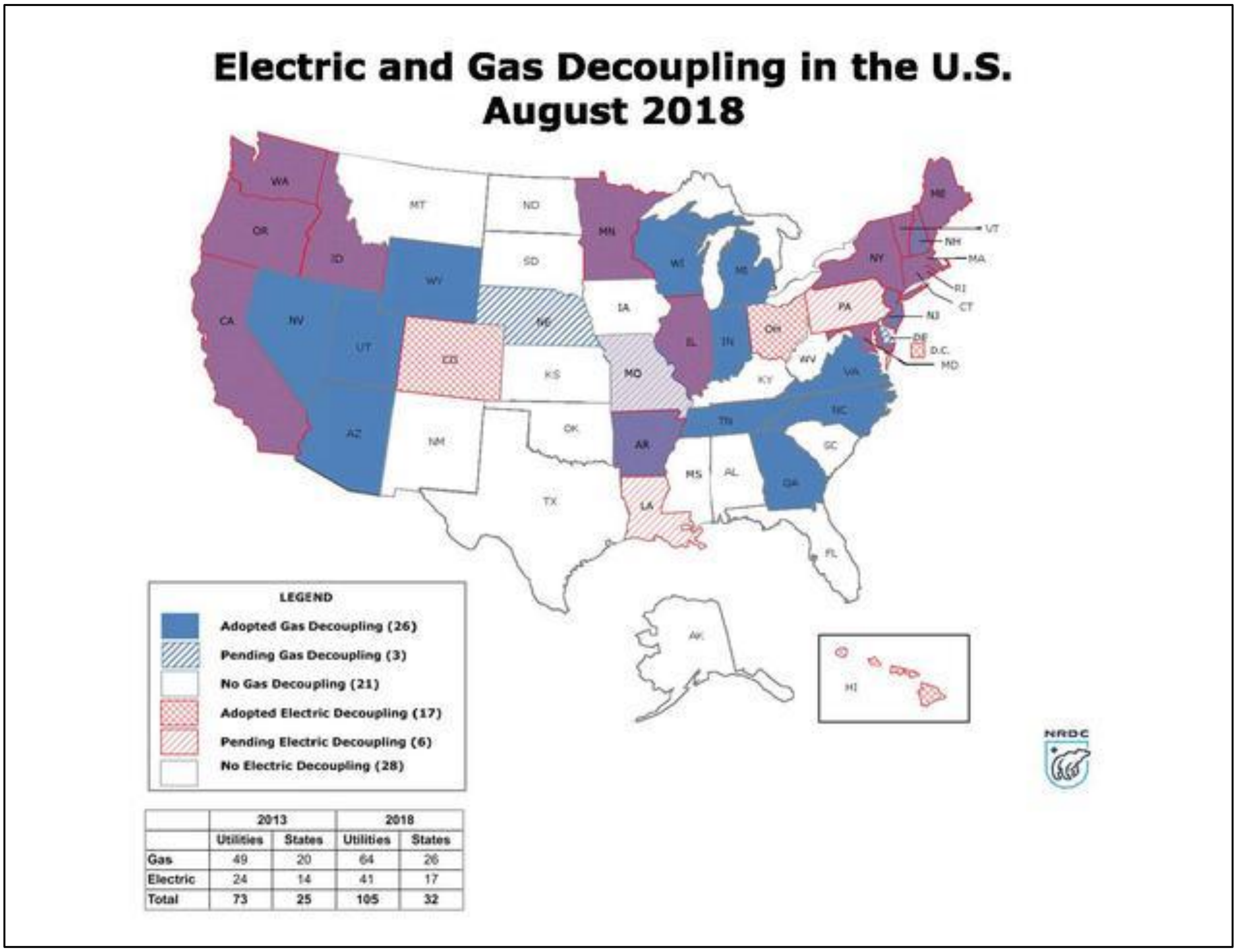
Another common approach to addressing the throughput incentive involves revenue regulation, also known as revenue decoupling. Under revenue decoupling, the commission establishes the utility's revenue requirements in a rate case in the standard manner. Retail rates are then periodically adjusted (usually annually, through a rider) to reconcile the difference between actual and authorized revenues. If the utility under-recovers, there will be a surcharge on customers' bills to make up the difference. Conversely, if actual revenues exceed authorized revenues, there will be a credit on customers' bills. The goal is to ensure that the utility receives its revenue requirements — nothing more and nothing less — and is not penalized for taking actions that are in the public interest but reduce sales.[66] In May 2006, a MADRI working group developed and published a revenue stability model rate rider at the request of the MADRI Steering Committee.[67] This detailed proposal was one of the earliest attempts to mitigate the throughput incentive through a decoupling mechanism. Since then, many states have adopted decoupling mechanisms for regulated electric utilities, as indicated in Figure 3.

65 See for example: National Action Plan for Energy Efficiency (2007, November). *Aligning utility incentives with investment in energy efficiency: A resource for the national action plan for energy efficiency*. Prepared by Val R. Jensen, ICF International. Retrieved from: https://www.epa.gov/sites/production/files/2015-08/documents/incentives.pdf.

66 RAP produced two useful references on this topic, the first a guide to theory and the second a manual for designing decoupling mechanisms: Lazar, J., Weston, F., Shirley, W., Migden-Ostrander, J., Lamont, D., and Watson, E. (2016). *Revenue regulation and decoupling: A guide to theory and application.* Montpelier, VT: Regulatory Assistance Project. Retrieved from: https://www.raponline.org/knowledge-center/revenue-regulation-and-decoupling-a-guide-to-theory-and-application-incl-case-studies/; Migden-Ostrander, J., and Sedano, R. (2016). *Decoupling design: Customizing revenue regulation to your state's priorities.* Montpelier, VT: Regulatory Assistance Project. Retrieved from: http://www.raponline.org/knowledge-center/decouplingdesign-customizing-revenue-regulation-state-priorities.

67 The model rate rider is archived on the MADRI website at: http://www.madrionline.org/wp-content/uploads/2017/02/madrimodelraterider-2006-05-16-1.pdf.

Figure 3: Status of Decoupling Policies in the US[68]



	2013		2018	
	Utilities	States	Utilities	States
Gas	49	20	64	26
Electric	24	14	41	17
Total	73	25	105	32

3. Utility Capital Bias

As discussed above, the IDP process will help regulators identify system needs and the types of resources that could potentially meet those needs. Traditionally, the utility would own and control the assets meeting those needs. But now some of the identified system needs can best be met through DERs. In addition to posing problems with cost recovery, these types of resources can also erode utility shareholder profits under the traditional COSR model.

Under traditional COSR, utilities create shareholder value by adding capital assets to their rate base and earning a rate of return on the residual value of these assets as they depreciate. The carrying cost on capital assets represents the time value of money and risk born by utility investors. To continue generating shareholder return, utilities must continually replenish and expand the rate base. In contrast, operating expenses are usually treated as a pass-through expense and do not contribute to utility earnings. This creates a utility investment preference for

68 NRDC (2018). Gas and electric decoupling [web page]. New York: Natural Resources Defense Council. Retrieved from https://www.nrdc.org/resources/gas-and-electric-decoupling.

capital expenditures (CapEx) rather than operating expenditures (OpEx) when seeking solutions to address grid needs — a "capital bias."[69]

The legacy regulatory model works well when the utility is the monopoly provider of grid services and when grid services are universally provided through capital investments (e.g., poles, wires, substations, etc.). However, this paradigm is being challenged by the emergence of customer-sited DERs that are capable of providing equivalent grid services, often at lower costs. Under the status quo, any distributed assets that delay or eliminate utility distribution system investment will reduce shareholders' opportunities to earn authorized profits. But ideally the decision to meet system needs through asset-based solutions or service-based solutions will be decided based on which solution set provides the best value to customers, rather than which solution set has more favorable regulatory treatment for shareholders.

Regulators are investigating opportunities to level the playing field between CapEx and OpEx for the provision of grid services. One option is to allow utilities to earn a rate of return on total expenditures (TotEx), similar to how they earn a rate of return on CapEx. CapEx and OpEx could potentially earn different rates of return based on different costs of investment or risk.[70] The Illinois Commerce Commission has initiated a rulemaking to allow utilities to rate-base investments in cloud-computing software, if it reduces total costs, as an option to address the capital bias in one area of utility investment.[71]

Performance based regulation (PBR) offers another option for addressing capital bias and aligning utility shareholder interests with least-cost IDP solutions.[72] PBR consists of a suite of tools that regulators can mix and match to best suit the needs and norms of their jurisdiction.

The most common approach to PBR worldwide is the multiyear rate plan, which is a variation on traditional COSR that enables utilities to operate for several years (typically four or five) without a general rate case. An "attrition relief mechanism," which automatically adjusts rates or the revenue requirement in between rate cases using forecasts or indexed trends to predict future utility costs, forms the heart of the multiyear rate plan.[73] This is considered a form of PBR

69 In academic circles, the capital bias is often referred to as the Averch-Johnson effect, based on a landmark journal publication: Averch, H., and Johnson, L. L. (1962). Behavior of the firm under regulatory constraint. *American Economic Review, 52*(5), 1052–1069. Retrieved from: https://www.jstor.org/stable/1812181?seq=1#page_scan_tab_contents.

70 This option is discussed in: Advanced Energy Economy (2018, June). *Optimizing capital and services expenditures: Providing utilities with financial incentives for a changing grid*. Retrieved from: https://info.aee.net/hubfs/PDF/Opex-Capex.pdf.

71 ICC (2017, December 6). *Illinois Commerce Commission on its own motion initiating proposed rulemaking relating to the regulatory accounting treatment of cloud-based solutions.* Case No. 17-0855. Retrieved from: https://www.icc.illinois.gov/docket/CaseDetails.aspx?no=17-0855.

72 Two recent publications on performance-based regulation may be helpful: Lowry, M., and Woolf, T. (2016). *Performance-based regulation in a high distributed energy resources future*. Ed. Schwartz, L. Vol. FEUR Report No. 3. LBNL-1004130. Retrieved from: http://eta-publications.lbl.gov/sites/default/files/lbnl-1004130.pdf; Littell, D. et al. (2017). *Next-generation performance-based regulation: Emphasizing utility performance to unleash power sector innovation.* Golden, CO: National Renewable Energy Laboratory. Regulatory Assistance Project. Technical Report NREL/TP-6A50-68512. Retrieved from: https://www.nrel.gov/docs/fy17osti/68512.pdf.

73 In the context of multiyear rate plans, "attrition" refers to the fact that the effectiveness of retail rates in recovering utility costs declines in between rate cases if utility costs are rising due to inflation or for other reasons.

because a utility that does a good job of controlling its future costs will collect revenue beyond the revenue requirement and increase shareholder profits, while one that fails to control costs will reduce profits.

More expansive forms of PBR can partially or fully replace rate base as the driver of utility shareholder profits. Instead of allowing an authorized rate of return on CapEx (or, as noted above, TotEx), regulators could instead establish performance incentive mechanisms (PIMs) as one of the drivers (or the only driver) of shareholder profits. PIMs consist of performance metrics, targets and financial incentives. PIMs have been employed for many years to address performance in areas such as reliability, safety and EE. In recent years, PIMs have received increased attention as a way to provide utilities with regulatory guidance and financial incentives regarding how well they enable the cost-effective deployment of DERs and the implementation of new technologies and practices.

A commission can use these and other similar tools to address the capital bias and greatly improve the IDPs produced by utilities and the value they provide to the public interest. By better aligning utility shareholder interests with those of customers, commissions are then free to optimize DER deployment and compensation through rate design or other DER compensation methodologies.

4. Potential for Stranded Assets

Under traditional COSR, only utility investments that are used and useful in providing service to customers are allowed in the utility's rate base. Under certain circumstances, past investments by utilities that were included in the rate base may be deemed to be no longer used and useful in serving customers. For example, investments in new air pollution control equipment at old coal-fired power plants may not be fully depreciated for decades, and some of those power plants may retire before the pollution controls are fully depreciated. These assets become stranded assets, and the utility and regulator will need to determine what elements of the original cost can be recovered from ratepayers and what elements should be paid for by the utility's shareholders.

The risk of stranding existing utility assets could be a challenge in developing and implementing a comprehensive IDP. This is because an IDP could reveal opportunities for distributed solutions that are cost effective for customers but that reduce the usefulness of, or demand placed on, existing assets. In other words, when developing an IDP, utilities might be concerned with whether their existing assets will be replaced before they are fully depreciated.

The challenge of assets becoming stranded as a result of increased reliance on DERs through detailed integrated distribution planning is likely to be most relevant for utility-scale generation and pollution control assets. This is generally not a big concern in MADRI states because most of those states have fully restructured their power sector and now preclude utilities from owning generation assets.[74] However, there is also a possibility that investments in the distribution

[74] In some jurisdictions, *holding companies* can own distribution utilities *and* merchant generation companies, but the finances of the regulated utilities and the merchant generators are isolated from each other. Stakeholders have sometimes disagreed over whether customers of the regulated utilities are completely protected from the financial

system itself (e.g., older, less-advanced metering technologies) could become stranded as new technologies emerge and as load profiles on distribution circuits change. This leads to a concern of ensuring that investments in new technology will be useful throughout their depreciable lives and will not become obsolete. Thus, utilities should consider the rapid pace of technological advancement and the possibility of creating a future stranded asset before making any kind of major infrastructure investment. One important strategy to reduce the risk of future stranded assets is for utilities to deploy technologies that utilize open technical standards.

5. Ownership and Control Issues

There is a debate across the country around which entities should be allowed to own, operate and control DERs and the services they can provide. Whereas traditional distribution facilities and services (e.g., poles and wires) seem to retain their natural monopoly status and features, there is debate about whether monopoly utility companies should be allowed to provide distributed energy services that competitive energy service companies can provide. Many utilities believe they are best suited to provide cost-effective DER solutions and see this as a natural expansion of their traditional role. Non-utility DER providers argue that these products and services belong in a competitive market.

The decision about what types of DERs, if any, utilities can own or control has implications for the development and implementation of a comprehensive utility IDP. If the least-cost solutions involve some combination of non-utility-owned assets, such as customer or third-party-owned solar and storage, utilities may want to control or set boundaries on how those assets are operated and how the owners will be compensated for services rendered. At a minimum, if the utilities cannot control the DERs, they will need some assurance that they will at least have visibility into the operation of those assets and that they will be operated in ways that meet identified distribution system needs. Without this, utilities will be likely to prefer a utility-owned solution, which could be costlier in some cases. One option is to add language to a standard interconnection contract that sets forth the obligations of the DER to provide the utility with the control or visibility required for reliable distribution system operations. The standard contract should be subject to regulatory approval to ensure that the requirements are not burdensome and a barrier to entry.

Disagreements about whether utilities should be allowed to own DERs could complicate an IDP proceeding. If utilities identify a DG solution as best for a particular area but they are not allowed to own the asset, it may be that they have to conduct some other kind of procurement. If they can't control the asset and the owner is not required to use it in a way that best minimizes distribution system costs, they may not be able to implement that solution. If they are allowed to own the generation asset, utilities will have a bias toward their own solutions and may not be as forthright with data for third parties who wish to bid for any open opportunities. If a utility is

risks of the merchant generators, but resolving that debate is beyond the scope of this guide. Ohio allows distribution utilities to apply for approval to own generation and recover costs in rates, but only if the utility can demonstrate a need to do so. Since Ohio restructured its utilities in 1999, no such approvals have been granted, but at least one such application was pending before the commission in March 2019.

permitted to own assets that compete with third-party suppliers, the operation of the business should, at a minimum, be functionally separated and subject to a code of conduct.[75]

For storage assets, there are ongoing conversations in MADRI states about if and under what circumstances utilities should be allowed to own storage assets behind the meter (e.g., on customer premises) or in front of the meter (FTM) (i.e., out on the distribution or transmission system). For example, stakeholders in Maryland developed a proposal to the Public Service Commission that would test different business models for deployment of storage, including one model that would allow utility ownership of FTM storage and another that would require utilities to contract with a storage provider for their needed distribution system services.[76] Lawmakers subsequently enacted a pilot program that requires each of Maryland's IOUs to propose at least two energy storage projects testing different business models, one of which must involve third-party or customer ownership of the storage assets.[77]

Because storage has unique attributes that allow it to provide multiple benefit streams (e.g., it can reduce distribution system costs, be bid into a wholesale market as a capacity resource and provide onsite backup energy for a site host), the decision about which entities can own and control the use of a storage asset has implications for what benefit streams will be prioritized and how those benefits will eventually accrue to ratepayers. For example, concerns have been raised that if utilities are allowed to own and rate-base the costs of storage investments, any revenue the utility might receive by bidding the resource into PJM needs to be netted out from the costs that ratepayers encumber to ensure that utilities do not earn a profit in the wholesale market on a rate-based asset. This is analogous to an off-system sale of generation where the lion's share of the revenues goes to the consumers with a small percentage kept by the utility as an incentive to engage in the best transaction possible. Conversely, storage that is owned by a third party might be optimized to reduce customer bills rather than meet distribution system needs, making it difficult for utilities to rely on that resource in an IDP.

C. Customers

The most fundamental challenge for customer adoption of DERs is obtaining compensation that is adequate to justify the investment. Customers will install DERs if they provide value through bill savings or other revenue streams that exceed installation and operational costs. Currently, it can be very difficult for customers to determine the total value proposition that DERs will provide. In addition, most decisions regarding compensation are made by other parties. Some of

[75] Migden-Ostrander, J. (2015, December). Power sector reform: Codes of conduct for the future. *Electricity Journal*, 28(10), 69–79. Retrieved from: https://www.sciencedirect.com/science/article/pii/S1040619015002274.

[76] Advanced Energy Economy, 2018.

[77] The *Energy Storage Pilot Project Act* (2019) amended the Annotated Code of Maryland, Public Utilities article, to create a new Section 7-216. Retrieved from: http://mgaleg.maryland.gov/2019RS/chapters_noln/Ch_427_sb0573T.pdf.

the key challenges regarding customer compensation that are determined by utilities or regulators are addressed in Appendix 2.

Customers who are interested in owning or hosting DERs also face their own unique set of challenges, relating to education, equity, access to financial products, physical limitations, and other issues. These challenges, summarized below, can make it difficult for an IDP to identify and execute the best, least-cost DER portfolio. Two non-profit organizations, GRID Alternatives and Vote Solar, maintain an online *Low-Income Solar Policy Guide* that explains many of these challenges and offers guiding principles, solutions, and real-world examples of overcoming them.[78] This website may prove useful to anyone seeking to include low income customers in plans to optimize deployment of DERs.

1. Customer Education, Engagement, and Acceptance

Customer education and engagement are critical to build momentum for DERs, especially in the residential sector. While large commercial and industrial customers often employ dedicated energy managers, the residential customer must consider energy choices with limited knowledge and a multitude of competing priorities. The benefits and costs of DER ownership are poorly understood by customers, and in many cases the policies delineating the benefits and costs are still being developed.

There is a clear need for customer education and engagement, and responsibility for educating customers will be shared by many parties, including DER providers, distribution utilities, governments (state and local), nongovernmental organizations, and state utility commissions. The extent that regulated distribution utilities play in this arena will be determined by rules governing the DER markets in each state.

Inertia may be the most powerful barrier to customer adoption of DERs. These technologies are still new and unfamiliar to many customers. DER marketers are competing not only for customers' dollars but also customers' time and attention. For a busy DER prospect with competing priorities, the decision to do nothing may be most attractive. The complex and lengthy process to purchase and interconnect a DER project may dissuade all but the most motivated customers. However, as customer familiarity with DERs increases and the financing, permitting and interconnection processes become more streamlined, the business case for DERs should begin to overcome customer inertia. Furthermore, certified third-party entities who can aggregate resources could provide an easier mechanism for customers to participate in some aspects of DER.

2. Low-Income Access to DERs

Despite the higher energy burdens experienced by low-income customers, these customers often face significant barriers to accessing DERs. These barriers may prevent low-income customers from realizing the potential benefits of DERs, including energy cost reduction, supply choice and enhanced reliability. The barriers to low-income customer adoption of DERs can generally be

[78] GRID Alternatives and Vote Solar. *Low-Income Solar Policy Guide* [Webpage]. Retrieved from https://www.lowincomesolar.org/.

segmented into four categories: financial barriers, physical barriers, housing barriers and market barriers. These barriers are briefly discussed below.

i. Financial Barriers

The high capital costs of DERs present a direct challenge for low-income customers who may lack savings or access to financing. Low-income customers often have lower credit scores that may disqualify them from financing or lock them into high interest rates that make the benefits of DERs less attractive. Many of the tax credits for DER ownership, such as the federal solar investment tax credit and the EV tax credit, are nonrefundable, which means that individuals cannot directly benefit from these incentives unless they have a tax liability. Some financial organizations that have provided funding for low-income customers do so to obtain offsets to their own tax liability, but this practice has not been widespread enough to have a significant impact in low-income communities. The *Low-Income Solar Policy Guide* provides a compendium of options and reference materials for addressing financial barriers on its "Financing" page.

ii. Physical Barriers

Low-income households are less likely to own their own homes, especially in urban areas, which makes it more difficult to install DERs with high capital costs. While renters may be able to access DR-enabled thermostats and low-cost EE measures, DERs requiring significant capital improvements, like rooftop solar and energy storage, are likely unavailable to renters. Low-income customers may also experience periods of housing insecurity, which presents a barrier to long-term planning for DER ownership. Low-income households are also more likely to live in multifamily buildings without access to their own roof. Virtual or public ownership structures for DERs, such as community solar and public EV-charging networks, may help overcome physical barriers to DER access.

iii. Housing Barriers

Low-income customers often live in housing that is older and that may be of poor structural integrity. A roof that needs repair is unlikely to be suitable for solar PV. Many low-income homes suffer from health, structural or safety issues, such as mold, leaky roofs or faulty wiring, as low-income people tend to be living in older buildings and have more limited income to invest in upgrades and repairs. These conditions may prevent installers from installing DERs, such as EE. Studies have found that a significant portion of low-income homes (more than 10% in one such study) have health and safety issues that prevent providers from delivering weatherization services.[79] Some utilities are working to remedy this by finding new funding or allocating additional existing funds to address these issues upfront.

[79] Refer, for example, to: (1) Carroll, D., Berger, J., Miller, C., and Driscoll, C. (2014). *National weatherization assistance program impact evaluation: Baseline occupant survey; Assessment of client status and needs*. Oak Ridge, TN: Oak Ridge National Laboratory. ORNL/TM-2015/22. Retrieved from: https://weatherization.ornl.gov/wp-content/uploads/pdf/WAPRetroEvalFinalReports/ORNL_TM-2015_22.pdf; (2)

iv. Market Forces

For many of the reasons described above, the low-income market is unattractive for many DER service providers, and low-income customers may have difficulty accessing their services. Additionally, low-income customers are often the target for scams, which erodes trust in the sales pitch of DER providers. Finally, language and cultural barriers make it difficult for low-income families to access the information they need to make informed choices about DERs.

D. DER Providers

The companies that offer DER products and services to utility customers must navigate between the realms of utility regulations, tariffs, and procedures on the one hand and wholesale electricity market rules on the other. This leads to a unique set of challenges for DER providers. Two of those challenges are explained in greater detail below.

1. Aggregation of Small DERs and Access to Market Revenues

As noted in Appendix 2, market revenues can be a key component of DER compensation. DER providers can play a key role in helping customers to access market revenues, but they face significant challenges. Their ability to overcome those challenges will influence whether DERs are deployed in an optimal fashion and whether a true least-cost IDP can be achieved in practice.

While individual DERs may be quite small (e.g., only a few kW), aggregated DER resources can add up to hundreds of MWs and can become significant players in distribution and wholesale markets. DER penetration is rising and becoming more diverse across the grid, which creates an opportunity to aggregate different DERs to provide a wider range of energy and grid services. Distributed solar, storage, EVs and targeted EE and DR can have a significant impact on the grid and have the potential of providing valuable services that obviate the need for distribution, transmission and generation investment. Third-party-driven investment in DER solutions is outpacing the ability of the existing markets to establish the required structures to enable DER participation and fairly compensate DERs for the services they provide. Appropriately, discussions at the federal level are now underway around the potential effects of DER integration into the bulk power system and the participation of DER resources in the wholesale markets.

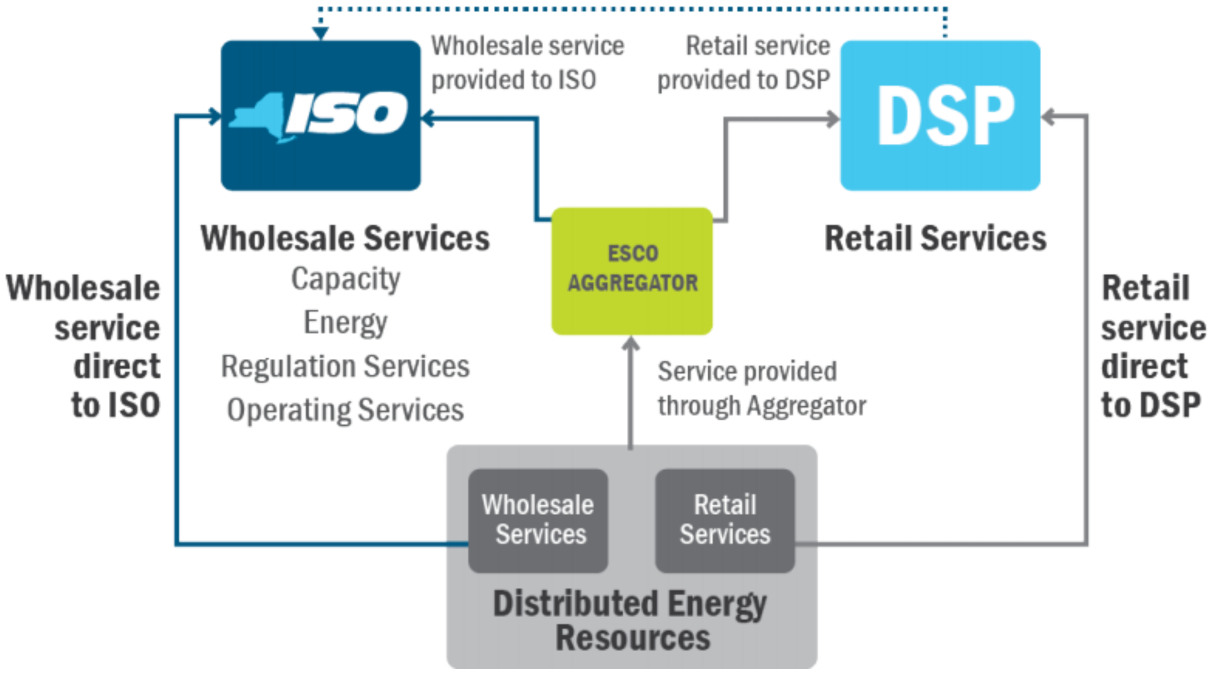
Rose, E., Hawkins, B., Ashcraft, L., and Miller, C. (2014). *Exploratory review of grantee, subgrantee and client experiences with deferred services under the Weatherization Assistance Program*. Oak Ridge, TN: Oak Ridge National Laboratory. ORNL/TM-2014/364. Retrieved from: https://weatherization.ornl.gov/wp-content/uploads/pdf/WAPRecoveryActEvalFinalReports/ORNL_TM-2014_364.pdf; and (3) Green & Healthy Homes Initiative (2010, October). *Identified barriers and opportunities to make housing green and healthy through weatherization*. Prepared by the Coalition to End Childhood Lead Poisoning. Baltimore, MD: Green & Healthy Homes Initiative. Retrieved from: https://www.greenandhealthyhomes.org/wp-content/uploads/GHHI-Weatherization-Health-and-Safety-Report1.pdf. The latter report notes (on page 5) that "Health and safety issues render homes ineligible for weatherization work though the degree may vary between [programs]. Overall, the average number of homes deemed ineligible in the pre-auditing or auditing phase was 12.88%; however, there is a wide variance in why programs find those homes ineligible."

Each ISO includes, among its eligibility rules, minimum size requirements for market participants. DERs, especially those owned by residential customers, are often too small to participate in wholesale markets on their own. However, if multiple DERs under the control of an aggregator of retail customers can meet the size requirement collectively, they may be able to participate. FERC, which has jurisdiction over ISO markets, established rules in Order 719 (2008) requiring each ISO to amend its tariffs as needed to allow for participation of aggregators of DR in organized wholesale electricity markets, unless such participation is limited by state and local regulatory authorities. As of June 2018, FERC had an open proceeding regarding whether to similarly allow aggregation of other DERs.

Multiple jurisdictions have taken steps to evolve their existing market structure to incorporate DERs, particularly aggregated DER from the distribution system. The California Independent System Operator (CAISO) made a distributed energy resources provider initiative (DERP) filing at FERC to facilitate participation of aggregations of small DERs in CAISO's wholesale energy and ancillary services markets. The FERC-approved DERP will provide new revenue streams for small DERs that can now sell directly into the wholesale market.

The New York Independent System Operator, Inc. (NYISO), through its DER Market Design Concept Proposal (MDCP), is evaluating its market design process that includes a strong foundation for DER integration. NYISO is working closely with the utilities of New York to develop a process for DER participation that includes situational awareness of DER output in its obligation to utility programs or their own load-serving objectives. Figure 4 below provides an overview of NYISO's vision for DER participation based on its ability to receive and implement dispatch signals that are driven by reliability or economics.

Figure 4: NYISO Vision for DER Participation[80]



The contribution of DERs to markets is becoming significant, but barriers remain for widespread participation of DERs in wholesale markets. These include:

- **Settlement requirement.** ISOs/RTOs want DER aggregators to provide services as reliably and transparently as conventional generators and do not want them to take advantage of price fluctuations by stepping out of the marketplace during times when wholesale energy prices are negative. This requirement can potentially discourage DER participation in markets, especially behind-the-meter DERs. Because of this 24/7 settlement requirement, if DERs generate or discharge to meet local demand when the wholesale price is negative, the DER operator must make a payment in the wholesale market even if no power was exported to the bulk power system.[81]
- **Interconnection requirement.** The interconnection process imposed by the ISOs on all DER participation in wholesale markets is cumbersome, imposes higher costs due to fees and hardware requirements and adds time to DER implementation in the field. These wholesale interconnection requirements exceed the requirements of typical interconnections on the distribution utility's system. DERs that have gained approval through the utility's process have to undergo a separate wholesale interconnection approval process. This process should be streamlined as the market evolves.

80 NYISO (2017, January). *Distributed energy roadmap for New York's wholesale electricity markets: A report by the New York Independent System Operator.* Retrieved from: https://www.nyiso.com/documents/20142/1391862/Distributed_Energy_Resources_Roadmap.pdf/ec0b3b64-4de2-73e0-ffef-49a4b8b1b3ca.

81 FERC Order 841 attempted to address this for energy storage resources by requiring wholesale prices to be applied to electricity consumed by distribution level storage resources that will later sell that electricity back to the wholesale market.

- **Metering requirement.** ISOs are applying the same metering and telemetry requirements for DERs as for traditional generators. The requirement of installing revenue recording meters for energy production and consumption along with the requirement to transmit data at short time intervals (such as one minute) is cost prohibitive for smaller DERs.
- **Wholesale/retail market boundary.** The definition of jurisdictional and technical boundaries for monitoring, control, visibility and oversight among the various stakeholders needs to be cleared up for better engagement of DERs at all levels.
- **Low net revenues.** Wholesale market participation for DERs interconnected at the distribution level is deemed unprofitable at this time. Revenue generation is likely to be low due to smaller DER sizes thereby requiring aggregation. However, aggregation requires significant upfront investment, creating a scenario for potential short- to medium-term losses, thereby inhibiting DER deployments.
- **Alternative revenue streams.** Many DERs participate in retail net energy metering (NEM) or DR programs. Participation in these programs may limit DER participation in new and upcoming DER wholesale market participation programs. This is done to prevent double payment under the retail programs and the wholesale programs. However, DER aggregators often choose the retail programs, as participation in the wholesale programs provide lower returns. Alternative revenue streams need to be developed to enable greater participation of DERs in the wholesale market.
- **Technical challenges.** Some technical challenges such as metering or the requirement to balance load versus supply (as set for traditional generators) remain today for the newer DERs. These challenges do not present a significant barrier but do need to be addressed by operators while designing a DER system that participates in the wholesale market.

2. Coordination of DER Operations between DER Providers and Utilities

The proliferation of DERs in the electric value chain has increased the interaction that utilities have with third-party entities, particularly those that use DERs to provide services in addition to traditional DR services. Typically, utility systems only have nameplate rating information about third-party DER providers, as interaction with the utility systems has been limited. However, smart inverters with inherent smarter functions are being deployed at a faster pace. These smarter functions have capabilities that can benefit not only the DER customer being serviced, but also the utility grid in the respective area. But taking advantage of these new capabilities presents new challenges for DER providers and utilities.

The California Public Utility Commission established a Smart Inverter Working Group (SIWG) that defined a road map for advanced smart inverter integration with utility distribution systems. The recommendations coming out of the SIWG have been used by many jurisdictions as a basis for reforming the interaction between DER providers and utilities, including in California’s Rule 21, which sets out interconnection requirements for generators wishing to connect to a utility distribution system.[82] Some of the recommendations have also been utilized by IEEE in its IEEE 1547 standards update, which will eventually make its way to multiple jurisdictions in the next few years.

[82] http://www.cpuc.ca.gov/Rule21/.

At the core of the coordination between utilities and DER providers is the communication architecture that will enable greater interaction and increase the efficiency of systems. Figure 5 below presents an overview of the communication between utilities and DER systems identified as individual DER systems, facility DER management systems (FDEMS) and retail energy providers (REPs).

Figure 5: DER Communication Landscape[83]

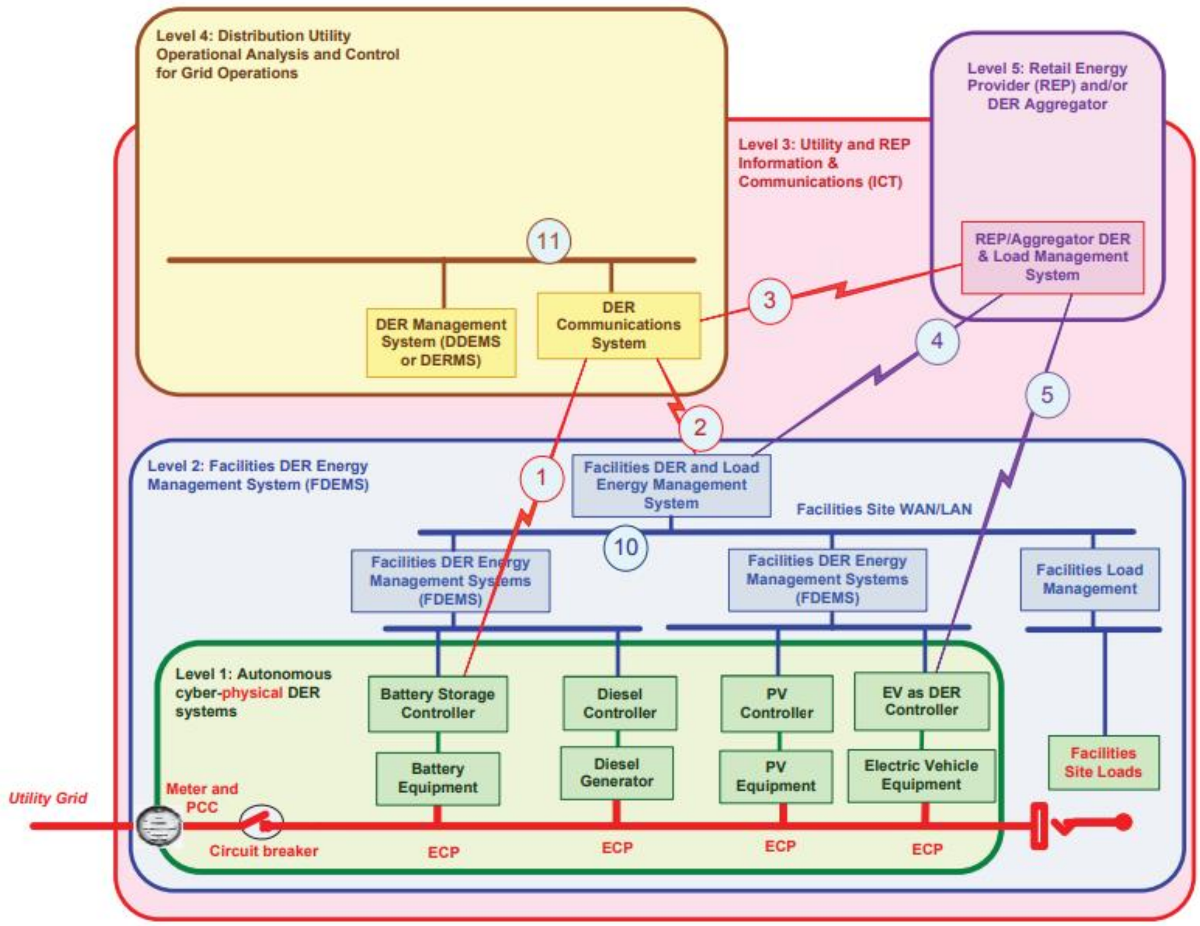
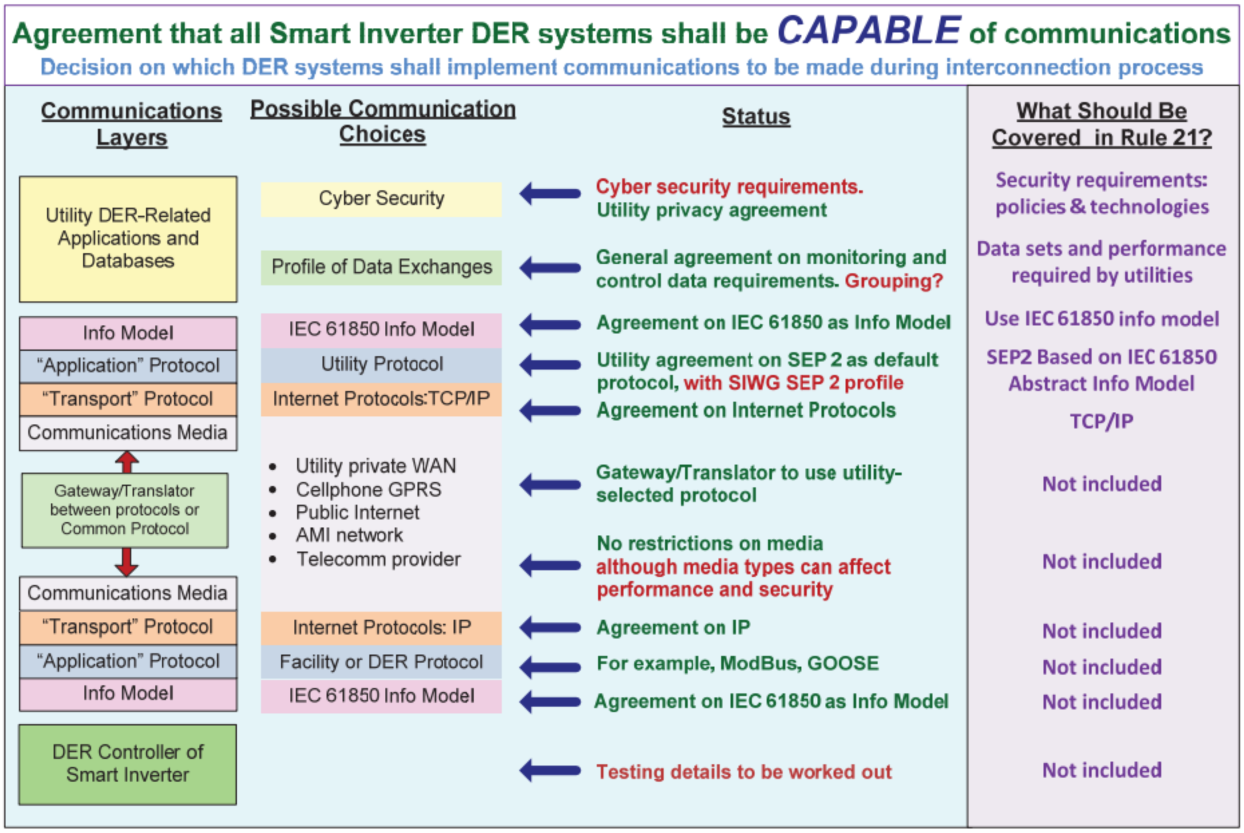


Figure 6 presents an overview of the status and expected coverage in California's Rule 21 for communication aspects of smart inverter systems.

83 CEC and CPUC (2015, February 28). *Recommendations for utility communications with distributed energy resources (DER) systems with smart inverters*. Smart inverter working group phase 2 recommendations. California Energy Commission. California Public Utilities Commission. Retrieved from: http://www.energy.ca.gov/electricity_analysis/rule21/documents/SIWG_Phase_2_Communications_Recommendations_for_CPUC.pdf.

Figure 6: Status and Expected Coverage in Rule 21 for Communication Aspects[84]



VI. OTHER CONSIDERATIONS FOR PLANNERS AND REGULATORS

This section examines some of the other policy and technical issues that will most significantly influence the assumptions, data and analysis of modeling results for an IDP, which commissions will need to be aware of as they guide and oversee the IDP process.

A. Policy Drivers of DER Growth

Across the United States, policymakers and regulators are enacting policies that are shaping the growth of DERs and net load in important ways. The energy policy toolbox is large, but an understanding of how these policies affect DER adoption is important for IDPs, especially at the DER forecasting stage. To facilitate a policy-aware IDP process, the following section summarizes several policy mechanisms impacting the growth of DERs in the MADRI region.

Clean Energy Goals and Expanded Opportunities

- Renewable portfolio standards (RPS) are policies that require utilities and other load-serving entities (LSEs) to source a certain amount of energy from renewable sources. Utilities and other LSEs demonstrate RPS compliance by obtaining renewable energy

[84] Ibid.

certificates (RECs), or solar RECs (SRECs), when there is a solar carve-out. Tradable RECs and SRECs create an opportunity for DG owners to monetize the value of renewable generation under the RPS framework.

- Energy efficiency resource standards establish targets for energy savings that must be fulfilled through the implementation of cost-effective EE programs. The EE programs may be run through the distribution utilities or through an independent EE utility.
- Other DER standards have been implemented for technologies such as DR[85] and energy storage.[86] Recently, several states have established energy storage targets, and others are considering targets for DR.[87]
- Community ownership models such as community solar or community energy storage allow customers to benefit from remotely sited DERs. Individual customers can benefit from fractional ownership of nonlocal DER resources through virtual net metering credits or other bill credits. This creates DER ownership opportunities for consumers that may not otherwise have access to DERs, such as renters or apartment dwellers. Additionally, virtual ownership provides flexibility to site DERs in areas of the distribution grid where DER services are more highly valued.
- Most states in the MADRI region struggle to achieve federal ambient air quality standards, and diligently look for low-cost opportunities to reduce power sector and transportation emissions. As DERs become increasingly cost effective, states may seek to include them in their plans for attaining the standards. State policies may also support accelerated DER deployment in those states that have adopted binding or aspirational carbon emissions targets.

Incentives for DERs

- Federal tax incentives include the solar investment tax credit, the qualified plug-in EV tax credit and the modified accelerated cost recovery system. These incentives facilitate greater investment in DERs. State and local tax codes may also include incentives for DER investment.
- Direct incentives for DERs include rebates for participation in EE and DR programs, spur DER deployment by offsetting capital costs.
- Subsidized financing programs, including interest rate buydowns, credit enhancements and loan loss reserves, can help buy down financing costs and increase access to DER financing to customers with less access to credit. Utility on-bill financing and property assessed clean energy (PACE) financing allow customers to repay DER loans through their electricity bills and property tax bills, respectively.

85 Pennsylvania Act 129 establishes demand reduction targets. Pennsylvania PUC (undated). Act 129 information [web page]. Pennsylvania Public Utilities Commission. Retrieved from: http://www.puc.state.pa.us/filing_resources/issues_laws_regulations/act_129_information.aspx.

86 New Jersey A3723 establishes a goal of 600 MW of energy storage by 2021 and 2,000 MW of energy storage by 2030. New Jersey: Governor Phil Murphy (2018, May 23). Governor Murphy signs measures to advance New Jersey's clean energy economy [web page]. Retrieved from: https://www.nj.gov/governor/news/news/562018/approved/20180523a_cleanEnergy.shtml.

87 New Jersey legislature (2018, May 23). Bill A3723: Establishes and modifies clean energy and energy efficiency programs; modifies state's solar renewable energy portfolio standards. Retrieved from: https://www.njleg.state.nj.us/bills/BillView.asp?BillNumber=A3723.

- Specialized financial institutions, such as the DC Green Bank,[88] are public or quasi-public entities that use public capital and bonding authority to spark private capital investment in clean energy projects, including DERs.
- Multiservice capabilities that allow DERs to supply multiple types of grid services can enhance DER value. For example, a building energy management system could provide curtailment services for both bulk resource adequacy as well as congestion relief on the local substation or distribution feeder. This enables value stacking, which improves the business case for DERs.

The preceding section is not meant to be an exhaustive discussion of policies supporting customer investment in DERs. Macroeconomic policies affecting everything from import tariffs on solar modules, the regulation of carbon pollution and even the federal funds rate will have important implications for DER adoption, but MADRI states have limited control over these issues. The aggregate impact of these energy policies, the economy, demographics and the DER market will each impact customer adoption of DERs and should be incorporated into IDP DER forecasts.

B. Technologies to Facilitate Two-Way Power Flows

The objective of this section is to identify system requirements that must be addressed in the formation of a two-way system at the lowest cost possible. The primary principles driving this transformation include:

- Enabling a system that is simple, transparent and adaptable to new technologies;
- Maintaining affordability while delivering a secure, reliable, and potentially more resilient energy system;
- Enabling cost-effective solutions for integration of complex new technologies;
- Maximizing potential benefits for all stakeholders, including stakeholders without DERs;
- Lowering cost of entry for all stakeholders;
- Encouraging innovation and utilizing governance structures to avoid duplication of resources;
- Enabling a market structure that will promote competition for distribution level stakeholders (including behind the meter customers); and
- Enabling a transparent and market-driven approach that encourages investment across stakeholders.

The transition of the grid to accommodate two-way power flow will require implementation of both technology and applications. Technologies are the specific devices derived from each of the key technology areas and applications are software driven solutions that effectively integrate the technologies to accomplish a specific set of goals or objectives. Power grid technologies can be generally included in one or more of the following key technology areas:

- **Advanced power grid components.** These components are the next generation power system devices taking advantage of new material technologies, nanotechnologies,

[88] DOEE (2018). Green Bank [web page]. Washington, DC: Department of Energy & Environment, government of District of Columbia. Retrieved from: https://doee.dc.gov/greenbank.

advanced digital designs and so on to produce higher power densities, better reliability and improved real-time diagnostics to greatly improve grid performance.

- **Advanced control methods.** These are the methods and algorithms that predict conditions on the grid, take appropriate corrective actions to eliminate or mitigate outages and power quality disturbances and optimize grid operations. They also support market interactions and enhance asset management and efficient operations by integrating with enterprise-wide processes and technologies.
- **Sensing and measurement.** These technologies enhance power system measurement and enable the transformation of data into information. They evaluate equipment health, grid integrity and congestion; support advanced protective relaying; eliminate meter estimations; detect energy theft; and enable consumer choice and participation.
- **Integrated communications.** High-speed, fully integrated, two-way communication technologies establish the infrastructure needed to enable the power system to become a dynamic, interactive infrastructure system for real-time information and power exchange. The vision is an open architecture that creates a plug-and-play environment that securely networks smart sensors and control devices, control centers, protection systems and users.
- **Improved interfaces and decision support tools.** In many situations, the time available for DER operators to make decisions has been reduced to seconds. The modern grid requires wide, seamless, real-time use of applications and tools that enable power grid operators and managers to make decisions quickly. These technologies convert complex power-system data into information that can be understood by human operators at a glance. These technologies include the role of artificial intelligence to support the human interface, operator decision support (alerting tools, what-if tools, course-of-action tools, etc.), visualization tools and systems, performance dashboards, advanced control room design and real-time dynamic simulator training.

Applications are needed to integrate the various grid technologies to achieve maximum improvement in reliability, economics, efficiency, environmental performance, security and safety. Power grid technologies and applications can be categorized into the major areas they impact, as identified below:

- **Customer technologies.** Consumer-enabling technologies that empower customers by giving them the information, tools and education they need to effectively utilize the new options provided to them by the evolving grid. These options include solutions such as AMI, home area networks with in-home displays and two-way communicating load control devices and DR programs. Other options include upgrades to utility information technology architecture and applications that will support plug-and-play integration with all future evolving grid technologies, including EVs and smart appliances. Table 2 provides a list of technologies that enable customer interaction with the utility grid.

Table 2: Customer Technologies

Key Technology Area	Technology
Advanced Components	Photovoltaics
	Microturbines
	Reciprocating Engines
	Fuel Cells
	Plug-In Hybrid Electric Vehicles (PHEVs)
	Electric Vehicles (EVs)
	Smart Appliances
	Thermal Energy Storage
	Distributed Storage (Batteries, Ultra-Capacitors)
	Inverters
	Wind Systems
Advanced Control	Demand Response (DR)
	Price Driven Load Management (PDLM)
	Home Energy Management Systems (HEMS)
	Electric Load as a Reliability Resource
	Advanced Metering Infrastructure (AMI)
	Smart EV Chargers
Sensing and Measurement	Radio Frequency Identification (RFID)
Integrated Communications	Home Area Networks (HAN)
	Internet 2 (IP6)
	Fiber-to-Home (FTH)
	5G
	WiMax (4G)
	Cellular (3G)
	Wi-Fi
	Zigbee
Improved Interfaces and Decision Support	In-Home Displays
	Advanced Consumer Portal

- **Advanced distribution technologies (substation to the customer).** These technologies improve reliability and enable “self-healing.” New technologies include smart sensors and control devices, advanced outage management, distribution management, distribution automation systems, geographical information systems and other technologies to support two-way power flow and DER operation. Table 3 provides a list of advanced distribution technologies from the distribution substation to the utility side of the customer meter.

Table 3: Advanced Distribution Technologies (Substation to Customer)

Key Technology Area	Technology
Advanced Components	Combustion Turbines
	Microturbines
	Fuel Cells
	Solar Photovoltaic Systems
	Wind Systems
	IntelliRupter Pulsecloser
	Inverters (4 quadrant capable)
	FAST Switches
	D-VAR / DSTATCOM
	SCADA enabled circuit switches
	Advanced Energy Storage (Electric)
	Thermal Energy Storage
	Flywheels
	Capacitors (Fixed or Switched)
Advanced Control	Distribution Management System
	Geographic Information System
	Advanced Outage Management System
	Customer Information System
	Distribution Automation
	Conservation Voltage Reduction
	Advanced Network Applications
Sensing and Measurement	Intelligent Electronic Devices
	Advanced Digital Protective Relays
	Smart Transformers
Integrated Communications	Broadband over Power Lines (BPL)
	WiFi
	WiMax (4G)
	Cellular 3G
	Microwave
	Fiber Optic
	Power Line Carrier (PLC)
	Z-Wave
Improved Interfaces and Decision Support	Engineering Information Systems (EIS)
	Workforce Management System (WMS)
	Asset Optimization Tools
	Transient and Dynamic Modeling
	Load Flow Modeling

- **Advanced distribution operation technologies (transmission system to the substation).** These technologies integrate the distribution system and customer technologies and applications with substations and RTO applications to improve overall grid reliability and operations while reducing transmission congestion and losses. Advanced distribution operation technologies include substation automation, integrated wide-area-measurement applications, power electronics and advanced system monitoring and protection schemes, as well as modeling, simulation and visualization tools to increase situational awareness and provide a better understanding of real-time and future operating risks. Table 4 provides a list of evolving grid technologies that can be applied to the grid between the transmission system and the distribution substation.

Table 4: Advanced Distribution Technologies (Transmission System to Distribution Substation)

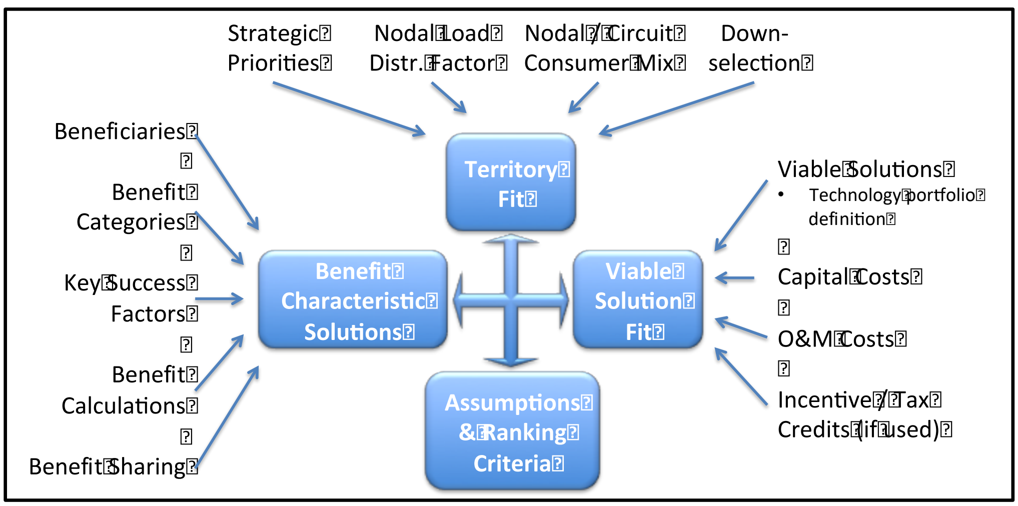
Key Technology Area	Technology
Advanced Components	Advanced Transformers
	Capacitor Banks
	Static VAr Compensator (SVC)
	Compressed Air Storage
	Pumped Hydro Systems
	Advanced Energy Storage (Electric)
	Utility Scale Solar Systems [Concentrating Solar Power (CSP Tower & CSP Trough System), Concentrating Photovoltaic System (CPV), Dish Sterling]
	Utility Scale Wind Systems
Advanced Control	Distribution System Modeling Software
	Demand Dispatch
	Substation Automation
	Advanced Feeder Automation
	Advanced Supervisory Control and Data Acquisition System (SCADA)
	Advanced Outage Managent System (OMS)
	Advanced Energy Management System (EMS)
	Condition Based Maintenance (CBM)
Sensing and Measurement	Phasor Measurement Units (PMUs)
	Wireless Intelligent Sensors
	Advanced Instrument Transformers
	Advanced Protection System
	Distributed Weather Data System
	Asset Health Monitors (IEDs)
Integrated Communications	Security Management Portal (SMP) Gateway
	Microwave
	Fiber Optic
	WiMax (4G)
Improved Interfaces and Decision Support	Engineering Information System (EIS)
	Capacity Planning Tools
	Workforce Management

A cost-benefit analysis (CBA) should be undertaken to identify leading technologies in a viable solution portfolio that can improve the reliability of the grid, lower costs to consumers and yield system, consumer and societal benefits. In the CBA, costs could be based on the full life-cycle deployment and operational cost for the selected viable solution portfolio. Benefits could be based on the differences in project baseline and final implementation outcomes, with benefits accruing to the three beneficiaries:

- Consumers — benefits that directly accrue to consumers served by the viable solutions (costs) implemented for their benefit;
- System — benefits that directly accrue to the utility's electric network served by the viable solutions (costs) implemented to benefit the electric network's reliability, economics and/or sustainability; and
- Society — benefits that broadly accrue to many consumers and society served by the viable solutions (costs) implemented to benefit society with improved reliability, better economics and improved sustainability.

To adequately apply the CBA for a particular jurisdiction, it is necessary to characterize the territory, and determine where, if applied, the viable solutions portfolio would provide the most benefits, as described by the beneficial characteristic solutions. Figure 7 summarizes a model that can be used to link benefits to solutions in a respective jurisdiction.

Figure 7: CBA Model Overview



C. Requirements for Transactive Energy Systems

Transactive Energy, as defined by the GridWise Architecture Council, is "[a] system of economic & control mechanisms that allows the dynamic balance of supply & demand across the entire electrical infrastructure using value as a key operational parameter." It captures the ongoing evolution from a centralized generation, transmission and distribution system to a complex two-way power-flow-enabled system that allows energy transactions at all levels of the value chain. A multitude of stakeholders and their resources including smart homes, smart buildings and industrial sites engage in automated market trade with other resources at the distribution system level and with aggregation or representation in the bulk power system. Communications are based on prices and energy quantities through a two-way market-based negotiation. A number of technologies and process improvements will be needed before transactive energy exchanges become commonplace, but establishing the communications network is arguably the first and most important step toward realizing value creation by expanding transactions. This section briefly discusses why the evolution toward transactive energy is important, the types of systems that are starting to appear, and the importance of communications protocols and data access in enabling transactive energy.

1. Why the Evolution toward Transactive Energy Is Important

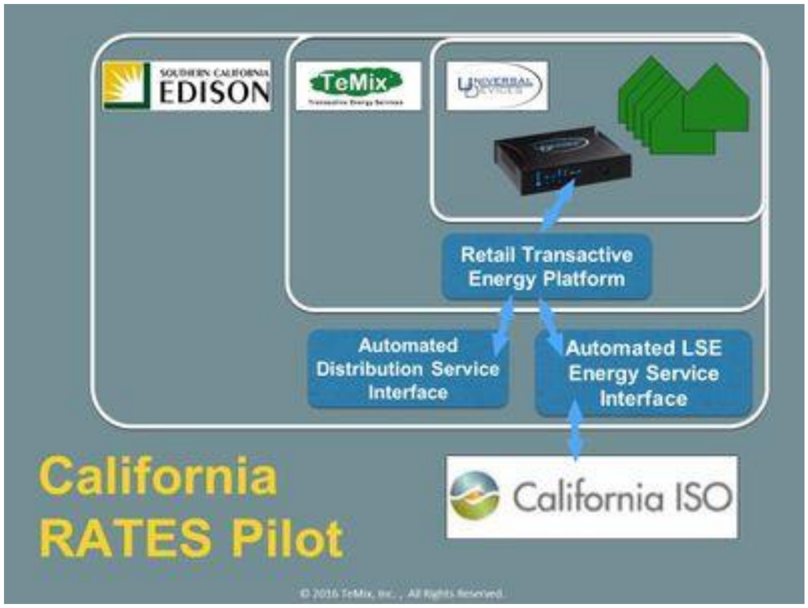
Resources at the distribution level are operated by devices that are optimized economically by a local intelligent controller that is administered by the user or an aggregator charged with representing the user's interest. The local controller receives transactive information and utilizes user preferences to operate or acquire resources to match supply and demand. These resources are part of a marketplace that allows market transactions to occur at the appropriate level in the value chain. The local controller communicates with the marketplace the resource availability based on user preferences and the willingness to pay, if it is a consuming device, and the price point to produce, if it is a producing device. All resources participate in the market by communicating their forecast to a range of price levels, thereby enabling the market mechanism to determine the price for the required balance of supply and demand.

The use of transactive energy systems that effectively optimize many DERs that have the power to produce or consume electricity concurrently requires improved active control and monitoring functionality. Modern energy management systems are improving and already have the capability to provide automation and control for a multitude of DERs. Transactive energy uses the mechanisms of control and monitoring in energy management to achieve value creation through mutually beneficial exchange. Realizing the promise of transactive energy is a natural next step in advancing energy management systems, especially at the distribution level involving energy-producing customers.

2. Transactive Energy Systems are Beginning to Appear

Many transactive energy pilots have been undertaken in the last few years. Figure 8 presents an overview of the retail automated transactive energy system being demonstrated with funding from the California Energy Commission. This pilot merges home and business automation development and deployment with electric power market design and a transaction platform. It helps coordinate operations and investment in wholesale transmission and generation system markets operated by CAISO, the distribution grid operated by Southern California Edison, an LSE, and customers who are producers and consumers of electricity.

Figure 8: California Retail Automated Transactive Energy System[89]



The above graphic depicts the high-level framework that could be deployed in a transactive energy system. At the core of this system is the ability of various devices in the electric value chain being able to communicate with one another in a market environment. The complex structure of the grid, which includes coupling among various entities, means that transactive energy systems are designed for multiple objective optimization that spans multiple time scales and hierarchies. Information and communication networks along with the physical networks are an integrated part of the transactive energy system. Information is exchanged among transacting parties (such as users, DERs, etc.), system operators, monitoring devices and control systems in a market-based environment.

3. Communications Standards and Protocols Are a First Step

There are literally dozens of DER communications standards, protocols and data models in use today. For example, some of the more familiar protocols include:

- OpenADR 2.0, which communicates price signals to activate automated DR resources;
- Green Button, which facilitates the transfer of retail customer energy consumption data, as described above in Section V.A.4; and
- EV-charging protocols, such as OICP (open intercharge protocol) and OCPP (open charge point protocol), that enable standardized data sharing among distribution system operators and EV-charging equipment operators and standardized communications between the cloud and EV chargers.

Communications standards, protocols and data models enable the transfer of messages among DERs, applications, aggregators, distribution system operators and transmission system

89 CEC (undated). Rates: Retail automated transactive energy system; Rates pilot overview [web page]. California Energy Commission. Retrieved from: https://rates.energy/overview-1

operators. The messaging requirements for transactive energy can be classified into the following:

- Resource management
    - Enrollment/registration
        - Asset owners/utility programs
        - Discrete devices
- Targeting/groupings of resources
- Operations messaging
    - Behavior profiles/schedules
    - Emergency dispatch
    - Advisory
        - Requests/prices/incentives
        - Schedules
- Reporting/monitoring
    - DER information/status
        - Configuration
        - Metering/performance
    - Notifications/alarms
        - Status/availability
- Transactions
    - Bids
    - Negotiations/forecasting
    - Transactions/measurement and verification/settlements

Transactive energy systems can use existing messaging protocols for direct or indirect control of DERs, various management functions, reporting, metering and transactive functions.[90] Technical standardization of transactive energy can be accelerated by extending existing protocols. The industry and stakeholders will find transactive energy easier to implement by using or evolving existing protocols or standards that work well with the control mechanisms of today. For example, blockchain is an evolving distributed ledger concept for delivery and acceptance of transactions at the DER level. At the time of this writing, blockchain in the energy management and control space is probably too new for stakeholders to make an informed judgment on the adoption and implementation of blockchain-based transactive energy systems.

4. Data Access Is a Prerequisite to Transactive Energy System Development

Access to electronic energy usage data allows customers to track and manage their energy consumption and thus is a prerequisite to enabling customer engagement in transactive systems. A customer's ability to know and share his or her usage profile allows the customer to engage with utilities and other producers of energy to develop innovative customer solutions. Availability of usage data also empowers nontraditional stakeholders to support the transition to a modern grid. The current inability of many utility customers to access their data or authorize the use of their data inhibits the energy marketplace. Transactive energy systems by design will

90 Mater, J. (2017, June 13-15). *Leveraging Existing Communications Protocol for DER and Transactive Energy Communications.* Presentation to 2017 Transactive Energy Systems Conference & Workshop. Retrieved from: http://www.rb-cg.com/GWAC/2017%20TESC/James-Mater-30645.pdf.

include a platform where all customer and service providers have access to data. The platforms need to be user-friendly and simple for consumers.

A standardized approach to data access takes three basic forms:

- Customer and energy service provider data that can be securely accessed in a timely manner by the market players;
- Aggregated, anonymized stakeholder data that can be accessed by authorized third-party providers; and
- Energy data from the system made available to third-party stakeholders.

Recommendations for improved data access to authorized stakeholders include:

- **Foundational element.** Policymakers should develop and implement foundational policies to enable a data-rich energy environment that allows authorized information sharing between all stakeholders (utility and nonutility service providers and customers).
- Data Infrastructure — Information technology systems based on standards such as Green Button and Green Button Connect could be developed to store and share market-based data for all stakeholders.
- **Data release.** Processes should be developed to release authorized customer data in a simple and seamless manner. This process can follow some of the following principles:
  - Verify and authenticate credentials;
  - Use digital processes for instant acceptance;
  - Enable click-through experiences;
  - Use standard language for information sharing; and
  - Simplify and streamline stakeholder authentication processes with effective use of technology.
- **Varied forms of data.** Anonymized aggregated data should be made easily available to all stakeholders to facilitate development of energy products and services.
- Incentivize Adoption — Incentive mechanisms need to be developed to access data for customers and raise their awareness and understanding of opportunities to reduce energy usage and costs.
- **Data protection.** Safeguarding of customer data is pivotal to increase the participation of customers and stakeholders in a transactive energy-based market system. Programs such as Data Guard, developed by U.S. DOE, should be evaluated for adoption as a privacy protection program for utilities and third-party stakeholders who commit to a code of conduct.

The development of transactive energy-based market systems will ultimately depend on the implementation of these data access principles.

VII. CONCLUSIONS AND RECOMMENDATIONS

The emergence of DERs as practical, affordable power system resources is changing the nature of the distribution grid and the roles of utilities and regulators. There is no turning back to the days of one-way flows of power (and data), with all assets owned or controlled by utilities. Power system planning, including distribution planning, must adapt to this new reality to maintain reliability and minimize costs.

A key aspect of this necessary adaptation is to bring distribution system planning out of the shadows, to inject transparency and oversight into an activity that has traditionally – and for good reasons – been left to the utilities to manage on their own. Furthermore, this newly transparent process must be integrated, i.e., distribution planning must take into consideration how DERs change load profiles and how their deployment and operation can be coordinated with the development and operation of traditional utility infrastructure (e.g., substations, transformers, and distribution lines). In short, IDP will become a necessary part of maintaining reliability and minimizing costs.

This paper provides detailed guidance to public utility commissions on the opportunity and the challenges associated with instituting an IDP requirement for regulated utilities. We conclude with a few of the most important recommendations found herein:

- Commissions, if they have the authority to do so, should investigate IDP and eventually institute an IDP requirement for the electric utilities they regulate;
- Because the IDP process may affect and be affected by other regulatory proceedings (e.g., grid modernization initiatives, resource and transmission planning), Commissions should consider how to coordinate such efforts to minimize counter-productive policies, confusion, and workload for themselves, the utilities, and all stakeholders;
- Commissions should ensure that stakeholders have a distinct and prominent role in any IDP process, not only in reviewing draft plans but also in the early stages of plan development, given that the actions of customers and DER providers will ultimately determine the rate and locations of DER deployment;
- When seeking solutions to identified grid needs, an IDP should give full, fair, and equal consideration to all traditional infrastructure options as well as all cost-effective DERs, including combinations of geographically-targeted DERs that constitute NWAs;
- In states that have adopted public policies favoring DERs or specifically promoting their deployment, the evaluation of solutions to grid needs should reflect those preferences and the plan should address the need to accommodate customer deployment of DERs;
- Hosting capacity analysis and hosting capacity maps should be included in an IDP, and are a crucial outcome of the planning process that can be used to steer DER deployment to where it is most valuable and expedite interconnection requests;
- Commissions, the utility planners they regulate, and other stakeholders should expect IDP to be challenging, at least initially, as it is a relatively new practice, but understand that methods and tools will improve over time, best practices will be identified and improved, and local experience and knowledge will grow with each iteration of the planning process;
- Some of the key challenges that will need to be addressed by all parties to optimize IDP outcomes include:

- Developing staff expertise and capacity for IDP and IDP oversight;
- Designing retail rates and compensation mechanisms to send appropriate price signals and provide fair compensation for the system value of DERs;
- Making the locations, capabilities, and operational status of DERs more visible to utility planners and transmission system operators;
- Adapting cost of service regulation and utility business models to make utilities indifferent to or supportive of cost-effective DER deployments;
- Educating customers about DER options and ensuring that low-income customers have reasonable opportunities to share in the benefits; and
- Enabling aggregations of DERs to provide bulk power system and distribution system services and receive compensation for those services.

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GLOSSARY

action plan. The component of a completed IDP (integrated distribution plan) that identifies specific activities to be taken to address near-term system needs.

advanced distribution management system (AMDS). A software platform that enables the distribution system operator to optimize grid performance (for example, voltage levels and reactive power) and automate some fault detection, isolation and restoration functions.

constraint. Any condition or consideration that may limit the capability of a distribution system component to serve load. Constraints on the distribution system can be related to equipment thermal ratings, power quality criteria that must be satisfied, reliability criteria, worker safety requirements or the need for system protection.

distributed energy resource (DER). Although defined differently in the statutes, regulations or policies of each jurisdiction, this term virtually always encompasses behind-the-meter distributed generation and electricity storage. In some jurisdictions, it may also include some combination of demand response, energy efficiency, electric vehicles, and in-front-of-the-meter generation or storage resources that are interconnected at distribution voltages.

distributed energy resource management system (DERMS). A software platform that enables the monitoring and controlled operation of DERs to meet customer or system operator objectives.

fault analysis. A technique used to identify potential anomalies in the flow of current on the distribution system. In an IDP context, fault analysis can model where faults are likely to occur in the system and define strategies to resolve power system failures.

hard versus soft DER costs. Hard costs include the costs of DER components and any associated equipment needed to operate the DER, for example solar panel and inverter costs. Nonhardware costs, such as permitting fees, the labor for installing panels and customer acquisition costs, are considered soft costs.

hosting capacity. The amount of DERs that can be accommodated on the distribution system at a given time and at a given location, under existing grid conditions and operations, without adversely impacting grid safety or reliability and without requiring significant infrastructure upgrades.

integrated distribution planning (IDP). A process that systematically develops multi-year forecasts and plans for the future of a distribution grid, considering both traditional infrastructure investments and non-wires alternatives as options for meeting forecasted needs. The acronym IDP may refer interchangeably to either the planning process or the plan it creates.

net load. In the context of IDP, the gross customer load minus any portion that will be served by behind-the-meter DERs.

non-wires alternative (NWA). A combination of DERs that cost effectively eliminates or defers the need for a traditional infrastructure investment on the distribution system.

partial requirements rate. A retail electricity tariff for customers with behind-the-meter DERs who require supplemental power when their demand exceeds their self-supply capacity, maintenance power when their DERs undergo scheduled maintenance and emergency power when their DERs have unscheduled outages.

power flow analysis. An analysis of the operational characteristics of the existing and planned distribution grid, including how conditions change in relation to customer load and DER adoption scenarios. Power flow analysis estimates voltages, currents and real and reactive power flow, which are used to identify constraints on the distribution system and identify options to resolve system constraints.

power quality assessment. An assessment of the impact to power quality of increased penetration of intermittent renewables and inverter-based DERs on the distribution system, including voltage sag and harmonic disturbances. Violations of power quality rules can reduce the efficiency of the distribution system and damage sensitive equipment.

renewable energy certificate (REC). A tradable certificate that represents the property rights to the environmental and renewable attributes of one megawatt-hour of electricity that is generated and delivered to the electricity grid from an eligible renewable energy resource. Load-serving entities that are subject to a state renewable portfolio standard can use RECs to demonstrate that they have procured sufficient renewable energy to comply with those standards. Companies and individuals that wish to voluntarily make claims about use of renewable energy may also purchase RECs.

telemetry. An automated communications process for transferring data electronically between remote locations, for example transferring state-of-charge information from a battery to an aggregator or system operator via a radio signal.

time of use rates (TOU). Retail pricing structures that divide the week into blocks of time during which electricity has different prices.

transactive energy. A system of local markets for DER compensation that operate automatically on a peer-to-peer level, overseen by the utility or another regulatory body.

value of resource. Compensation for DERs is fixed for each type of resource (e.g., distributed solar PV) and is calculated based on typical values for the benefits to the grid provided by that resource type.

value of service. Compensation for DERs is based on the value of the services provided, determined by type, location and time of each service, and is agnostic on the suitable technology used.

visibility. In the context of IDP, this term refers to the extent to which a system operator has accurate information regarding the existence, location, capabilities and current operational status and condition of a DER or another component of the distribution system.

APPENDIX 1: A PJM PERSPECTIVE ON PJM/UTILITY INTERACTIONS

The following perspective on IDP was provided by PJM staff for consideration within the context of this guidance document.

PJM would like to partner with commissions and distribution utilities to solve challenges that may exist in developing and implementing an IDP. PJM does not do central planning and will not provide advice regarding the best locations for DER deployment other than that provided by PJM market signals, but PJM can work with commissions and distribution utilities to review the impacts of anticipated deployments. Specifically, there may be technical barriers that must be overcome to foster coordination between the wholesale and retail markets as well as the distribution and transmission systems.

As DER deployment continues growing at the distribution level, the advantages of technologies, such as smart inverters, will increase in importance. PJM has required these technologies to be utilized for wholesale grid interconnection and encourages commissions to ensure the technologies are utilized for distribution-connected DERs and the settings configured to reinforce both distribution and transmission grid reliability.

During grid contingencies, such as the trip of a large generator or load, conventional generators must provide dynamic support to the grid in the form of ride-through. When frequency or voltage becomes unusually high or unusually low, generators with ride-through capability remain connected for a period of time. Ride-through capability ensures grid reliability during operational contingencies.

PJM has implemented ride-through requirements for DER that interconnect to the wholesale grid under federal jurisdiction. During the PJM stakeholder process discussions leading up to the adoption of this requirement, inverter manufacturers reported little or no increase in DER costs associated with implementing ride-through functionality.

For DG and storage connecting to commission-jurisdictional distribution lines, existing commission rules govern behavior during grid contingencies, including ride-through functionality. PJM urges MADRI commissions to consider revising rules in the future so that ride-through functionality is required, per the IEEE 1547-2018 standard. PJM would welcome the opportunity to work with commissions to study the IEEE 1547-2018 standard and to craft a DER interconnection rule that includes both voltage and frequency ride-through.

Additionally, as commissions consider deployment plans for DERs, PJM encourages any hosting capacity studies to also consider transmission grid impacts. Very small DERs are unlikely to have impacts on high-voltage transmission lines by themselves. However, large numbers of small DERs concentrated in a geographic area can and do create impacts. Therefore, it may be important for commissions and distribution utilities to coordinate with PJM on any hosting capacity studies to identify transmission impacts that could occur from anticipated deployments.

APPENDIX 2: OPTIMIZING DER DEPLOYMENT THROUGH SMART RATE DESIGN AND APPROPRIATE CUSTOMER COMPENSATION

If retail rate design and customer compensation do not reflect the true value of DERs, DERs will not be deployed at optimal levels. Customers' decisions about whether to install DERs will always involve an examination of their energy consumption patterns, their retail rate design and prices, and the potential costs or cost savings of installing the DER. Getting retail rate design and customer compensation right is critical to ensuring that customers with DERs can enjoy bill savings without creating any subsidies from other customers. It is equally important in the design of rates to ensure that the right price signals are sent and that rates align with costs. This will matter for all customers, whether they have DERs or not, and it will help to optimize the efficient and cost-effective use of DERs and utility investments in the grid.

With those goals in mind, in February 2016, RAP prepared a report at the request of the MADRI Steering Committee on designing tariffs for customers with DG.[91] The National Association of Regulatory Utility Commissioners (NARUC) later published its comprehensive reference on this topic, hereafter referred to as the NARUC manual, which cites the MADRI paper on designing tariffs as well as many other resources.[92] RAP has also independently published two guides on smart rate designs that align energy charges and demand charges with long-run costs of service, one for residential customers and one for nonresidential customers.[93] Some of the key takeaway messages from these reference documents are summarized below.

A. Retail Rate Design

It is well understood that the costs of power supply in the PJM wholesale electricity market vary from hour to hour, day to day and year to year. They also vary by location. The variation in wholesale energy costs is expressed in short-term locational marginal prices that reflect the availability of generators with different operating costs and the availability of transmission capacity to deliver generated electricity to load. PJM's capacity market prices, which reflect the longer-term cost of securing adequate generation and demand resources to meet projected peak demand, also vary by location and year (not hourly). Customer demand for energy in every hour of every day is the key driver of short-term wholesale energy costs. Customer demand during critical peak hours for the bulk power system is the key driver of longer-term transmission and wholesale capacity costs.

[91] Migden-Ostrander, J., and Shenot, J. (2016). *Designing tariffs for distributed generation customers*. Montpelier, VT: Regulatory Assistance Project. Retrieved from: https://www.raponline.org/knowledge-center/designing-tariffs-for-distributed-generation-customers/.

[92] NARUC (2016). *Manual on distributed energy resources rate design and compensation*. Staff subcommittee on rate design. Washington, DC: National Association of Regulatory Utility Commissioners. Retrieved from: https://www.naruc.org/rate-design/.

[93] See: Lazar and Gonzalez. (2013). *Smart rate design for a smart future*. Montpelier, VT: Regulatory Assistance Project. Retrieved from: https://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/; and Linvill, C., Lazar, J., Dupuy, M., Shipley, J., and Brutkoski, D. (2017). *Smart non-residential rate design*. Montpelier VT: RAP. Retrieved from: https://www.raponline.org/knowledge-center/smart-non-residential-rate-design/.

Distribution systems are sized primarily to meet peak demand at the local level. There are few variable operating costs in the distribution system. Almost all delivery costs are fixed in the short term. Thus, the costs of delivery by electric distribution utilities tend not to vary by hour or season in the short term. Customer demand during critical peak hours for the distribution system is the key driver of longer-term distribution capacity costs.

Retail rate designs can send price signals to customers that reflect these short-term and longer-term cost drivers and thus encourage consumption that is economically efficient (i.e., customers use energy when its value exceeds its cost). Over the long term, all costs are variable. PJM's wholesale capacity market secures generation capacity three years in advance. Investments in transmission and distribution capacity eventually wear out and must be replaced. The size and cost of those replacements will depend on peak capacity needs. Thus, changes in a customer's individual peak demand, or the customer's contribution to system peaks at the distribution level or the bulk power level, can increase or decrease long-term capacity market costs and transmission and distribution costs. This reality can be reflected in retail rates even though some of these costs are not variable in the short term.

Time varying rates can send a price signal that better reflects the cost of electricity supply and delivery and gives customers one avenue for reducing their bills and recovering the cost of their investments. These kinds of rates help ensure the benefits of DER are passed on to consumers in their bills and that the DER providers are fairly compensated for the benefits being provided. Customers can use behavior or technology (e.g., DERs) to save money by reducing consumption or shifting usage away from peak periods. One type of time-varying rate and one of the most popular is time of use rates (TOU), which divide the week into blocks of time during which electricity has different prices. For example, the volumetric rate for electricity supply might be five times higher during the afternoon and early evening of weekdays when compared to overnight hours. The length of the blocks of time, the number of blocks, the ratio of on- and off-peak prices and other variables can all be adjusted by the commission to best suit its jurisdiction's needs. A critical peak pricing component can be added to a TOU rate that reflects the unusually high cost of procuring power during a system peak when customers are being encouraged to moderate usage. It is used infrequently throughout the year and typically for a limited number of hours.

Another type of time-varying rate is real-time prices. These rates follow the wholesale markets and generally expose the customer to the volatility and price risk that LSEs deal with every day. Since the customer is taking on that risk, they generally save money by avoiding paying a risk premium, even if they don't change their usage patterns, but they can also use behavior and technology to strategically use more or less electricity at different times of the day and further reduce bills. While the rate the customer will be paying is known either through the day-ahead or real-time wholesale markets, the customer does not have certainty more than a day out on what they will be paying for electricity supply. Because of the complexity, volatility and need to monitor market prices, typically only large customers subscribe to this rate. Residential customers of the Illinois utility ComEd have proven to be the only exception to this general rule in the PJM footprint: more than 10,000 of ComEd's residential customers have opted for real time prices — though it should be noted that this represents only a small fraction of the residential customers of this very large utility.

TOU rates can be offered on an opt-in or opt-out basis. Most consumer advocates prefer an opt-in basis in which customers can make an informed decision to alter their rate schedule. If customers are put on opt-out TOU rates and do not understand how the rates work, they could be the unwitting recipients of large bills — and the utility and the commission could be the recipient of a large volume of angry calls. Education is key. One helpful educational tool is to provide customers with a "shadow bill," which shows the customer on a traditional, non-TOU rate what that customer would have paid under a TOU rate. This gives the customer a point of comparison and an opportunity to experiment by altering usage patterns and seeing what the potential bill savings could be.

Utility commissions in the MADRI jurisdictions have authority to set retail rates for delivery and for default power supply. They cannot control the prices or the rate designs offered by competitive retail energy suppliers. Thus, compared to commissions regulating vertically integrated utilities, MADRI commissions have less ability to reflect long-term cost drivers in retail rates, though they still have some limited ability to do so. Table 5 provides an illustrative example of a TOU rate design that might be suitable for delivery (distribution) and default power supply. It sends price signals to the customer that reflect both short-term and long-term cost drivers. Delivery charges are somewhat lower for off-peak consumption and are much higher for critical peak consumption to send a price signal about long-term distribution capacity cost drivers. Default power supply charges are more variable than delivery charges because they reflect both the variability in long-term generation capacity costs and the short-term variability in energy costs.

Table 5: Illustrative TOU Rate Design for Restructured Jurisdictions

Distribution Charges	Unit	Residential
Customer Charge	$/Month	$4.00
Off-Peak	$/kWh	$0.040
Mid-Peak	$/kWh	$0.050
On-Peak	$/kWh	$0.060
Critical Peak	$/kWh	$0.240
Default Power Supply Charges		
Off-Peak	$/kWh	$0.03
Mid-Peak	$/kWh	$0.04
On-Peak	$/kWh	$0.08
Critical Peak	$/kWh	$0.50

Policy decisions around rate design are likely to influence DER adoption rates. In particular, attempts to change how much of the utility's costs are recovered through energy charges and how much through demand charges will make some DERs more valuable, and others less so. For example, shifting more of the cost recovery to demand charges will decrease the value of EE and DG but increase the value of DR and energy storage resources.

B. DER Compensation

Retail rate designs create inherent incentives for customers to install some types of DERs. Customers can avoid charges on their utility bills by installing DERs. If the avoided charges are greater than the cost of installing the DER, the customer saves money. But focusing exclusively on retail rates and customer bill savings overlooks the fact that some DERs can provide value to the distribution (or bulk power) system — not just to the customer with the DER. The challenge is to create appropriate compensation mechanisms for DERs that provide system value, so customers with DERs can receive that value and customers without DERs can benefit from it without subsidizing it.

There are at least four common mechanisms for compensating customers who install and operate DERs: (1) tariffs or bill credits, (2) market revenues, (3) power purchase agreements (PPAs) or contracts and (4) one-time payments or credits. The challenge is in assessing the potential revenue streams and determining the total value proposition that DERs will provide.

i. Tariffs or Bill Credits

Utility commissions across the country have most commonly addressed DER compensation through NEM tariffs for DG, rebates and incentive payments for EE measures and incentive payments or rate designs for DR programs. In addition to these common approaches, many commissions across the country are now conducting analyses to calculate compensation for DER using value of resource or value of service methodologies. In response to a growing interest in DER compensation issues, NARUC published the NARUC manual in 2016.

In value of resource approaches, compensation is calculated based on the specific resource or category of resources that provide benefits to the grid. The most common example is a value of solar tariff. For valuing the costs and benefits of DER to the grid, the NARUC manual notes:

> Most methodologies currently being used consider both the positive and negative effects of the following: 1. Avoided energy/fuel; 2. Energy losses/line losses; 3. Avoided capacity; 4. Ancillary services (may include voltage or reactive power support); 5. Transmission and distribution capacity (and lifespan changes); 6. Avoided criteria pollutants; 7. Avoided [carbon dioxide] emission cost; 8. Fuel hedging; 9. Utility integration and interconnection costs; 10. Utility administrations; 11. Other environmental factors; and 12. Reliability factors and costs.[94]

In value of service approaches, the compensation is based on the value of the service provided, based on the type, location and time of service, and is agnostic on the suitable technology used. The first step in this process usually is exploring the different services that DERs can provide to the grid. Providing energy is only one of the many services, and commissions must ensure that DERs are fully compensated for all grid benefits. In the fourth report from Lawrence Berkeley National Laboratory's Future Electric Utility Regulation (FEUR) series, *Distribution System Pricing with Distributed Energy Resources*,[95] the authors used as a starting point 24 smart inverter functions described in an EPRI technical report.[96]

Another compensation methodology is transactive energy (TE), which is a newer concept that compensates DER through local markets that operate automatically on a peer-to-peer level overseen by the utility or another regulatory body. The NARUC Manual describes it as follows:

[94] NARUC, 2016, 133. The manual cautions, in a footnote: "It is important that the costs and benefits under this strategy are similar to those afforded to traditional generation resources. If a jurisdiction identifies additional benefits, such as job creation, it should be considered outside the development of the rate itself and can be treated as an adder or compensated for in some other manner."

[95] Hledik, R., and Lazar, J. (2016). *Distribution system pricing with distributed energy resources*. LBNL-1005180. Berkeley, CA: Lawrence Berkeley National Laboratory. Retrieved from: https://emp.lbl.gov/publications/distribution-system-pricing.

[96] EPRI has since updated its report on smart inverter functions: EPRI (2016). *Common functions for smart inverters: 4th edition*. Palo Alto, CA: Electric Power Research Institute. Retrieved from: https://www.epri.com/#/pages/product/3002008217/?lang=en-US.

> TE is a concept developed by the GridWise Architecture Council (GWAC) and Pacific Northwest National Labs (PNNL). TE is both a technical architecture and an economic dispatch system highly reliant on price signals, robust development of technology on both the grid side and the customer side, and rules allowing for markets to develop that enable a wide variety of participants to provide services directly to each other. This "peer-to-peer" component differentiates TE from many of the other options discussed herein.[97]

Pricing these various grid functions is a complicated task for any commission. Ultimately, the goal of many jurisdictions will be to let local TE markets price the services. Value of resource and value of service methodologies could be used as an interim step toward TE or as a final step for commissions that decline to implement TE. At low levels of deployment and at the very beginning of deployment, NEM rates that credit DER customers at their full retail rate can continue to be used. Setting values of different benefits to the grid involves controversial issues, such as whether to use short-term or long-term costs and benefits. Additionally, the values will change over time and by location. The categories of different costs and benefits to be included in calculating a customer's compensation are also a subject of debate.

Any commission attempting to transition to one of the value-based methodologies should leave adequate time for a robust empirical study of the value DER can provide to the grid in its jurisdiction. Once the values are known, they can be implemented in different pricing models, as illustrated by the four indicative examples in the FEUR Report No. 4.[98] The buy/sell arrangement, also known as buy all/sell all, would include the value of resource or service methodologies, in which a customer pays the normal rates for retail delivery services and then receives compensation for the specific services provided to the grid. The procurement model more closely resembles TE, but in this case the utility requests proposals for needed services and aggregators bid to provide those services. The compensation earned by customers is solely governed by a separate bilateral agreement between the aggregator and customer. The last indicative example of pricing models is a DER-specific rate, which would be much like a partial requirements rate but for a separate subclass of residential and small commercial customers. The report also includes an indicative granular rate, which unbundles the different delivery services (and includes locational adders). Under this model, the DER customer avoids costs through self-supply but isn't necessarily provided direct compensation for all the value provided to the grid.

ii. Market Revenues

The seven ISOs existing in the United States today operate wholesale markets for electricity services in which various market participants compete to provide energy, capacity and ancillary services to LSEs. If they can meet eligibility requirements set by the ISOs, and successfully compete with other market participants, the owners of DERs can receive monetary payments for the values they provide to the bulk power system. The seven markets vary not only in their eligibility rules but also in how they compensate capacity and specific ancillary services.

[97] NARUC, 2016.
[98] Hledik and Lazar, 2016.

PJM has long allowed DERs to participate in its energy, capacity and ancillary services markets. Resources must meet certain minimum-size thresholds to participate, and those thresholds generally exclude participation by individual DERs, which tend to be very small. However, aggregations of small EE and DR resources have historically played a significant role in PJM's markets. For example, over 10,000 MW of EE and DR were procured by PJM in recent forward-capacity auctions. Other types of DERs have not participated as actively.

In February 2018, FERC issued Order 841, *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, which directed ISOs and RTOs to develop new rules for energy storage participation in the wholesale energy, capacity and ancillary services markets.[99] When implemented, Order 841 will favorably impact the cost effectiveness of energy storage as an NWA. The order specifically extends to allowing distribution-connected energy storage resources to participate in RTO/ISO markets.[100] Additionally, in a 2017 Policy Statement,[101] FERC clarified that energy storage resources might be able to recover their costs through both cost-based rates (i.e., rate base) and market-based rates concurrently. This means that FERC may approve energy storage assets used as NWAs to also participate in markets during the hours of the day or months of the year that they're not required to provide load reduction for the distribution system; however, the exact mechanics of this type of dual use asset have yet to be ironed out by the ISOs, RTOs and utilities.

In just the past few years, several state public utility commissions have begun to discuss whether to create markets for electricity services at the distribution system level. These markets could potentially be operated by the local utility or by a DSO. Although this kind of market does not exist anywhere today, it is actively under consideration in New York and California and could someday provide another avenue for DER owners to capture value through market revenues.

iii. Power Purchase Agreements or Contracts

Utilities often enter into PPAs with independent power producers or third-party energy service companies to provide energy, capacity or ancillary services. A PPA is a negotiated contract; thus, the terms and conditions vary from one PPA to the next. Utilities can compensate DER owners for different value streams (e.g., energy value and REC value) separately but more commonly offer compensation via bundled, fixed price per kWh rates. It is also possible for owners of PV and other renewable DG resources to sell undifferentiated power to a utility via a PPA and sell their RECs to another party via a separate contract. PPAs and contracts are more common in areas without an ISO.

[99] FERC (2018, February 15). *Electric storage participation in markets operated by regional transmission organizations and independent system operators.* Docket Nos., RM16-23-000; AD16-20-000; Order No. 841. Federal Regulatory Commission. Retrieved from: https://www.ferc.gov/whats-new/comm-meet/2018/021518/E-1.pdf.

[100] Ibid., paragraph 29.

[101] FERC (2017, January 19). *Utilization of electric storage resources for multiple services when receiving cost-based rate recovery* [policy statement]. Docket No. PL17-2-000. Federal Regulatory Commission. Retrieved from: https://www.ferc.gov/whats-new/comm-meet/2017/011917/E-2.pdf.

iv. One-Time Payments or Credits

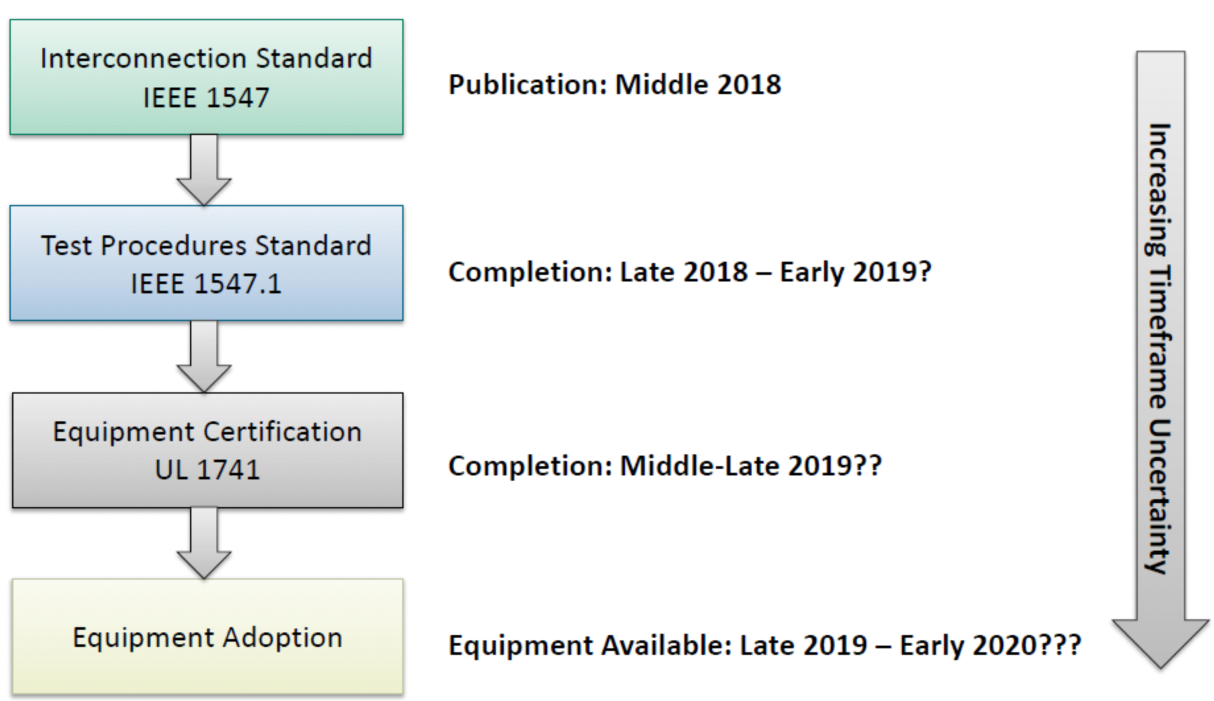
The federal government and many state and local jurisdictions offer or require utilities to offer one-time tax credits, rebates, up-front incentives and other forms of compensation to DER owners that often are not tied to utility or wholesale market revenues. There are many varieties and examples of these one-time payments, including the federal investment tax credit for PV, state and federal tax credits for new EV purchases, customer rebates for energy-efficient appliances, and up-front bill credits for customers who participate in a utility's direct load control DR program. All these options provide compensation to DER owners that is intended to reflect in some way the value those DERs bring to the utility system or to society.

APPENDIX 3: TIMELINE FOR IEEE ROLLOUT OF SMART INVERTER FUNCTIONS

IEEE has undertaken an effort to revise the IEEE 1547 standard that addresses the interconnection of distributed resources with power systems. An update to the standard, IEEE 1547-2018, was released in April 2018 that includes multiple recommendations from the smart inverter working group around functions and communications for interconnection of DERs. One of the major updates includes changes to the voltage and frequency ride-through functions. These changes will help ensure that DER capacity is not automatically tripped off every time there is a transient disturbance in power quality, which enables owners and aggregators to get more value from DERs.

The implementation of the IEEE 1547-2018 standard update is an ongoing process and is not expected to be done until 2020. **Error! Reference source not found.** presents an overview of the IEEE 1547-2018 update process that includes updates to the test procedures standard (IEEE 1547.1), followed by equipment certification by Underwriter Laboratory (UL 1741) in 2019. The updated standard is expected to be adopted by equipment manufacturers by 2020. The successful rollout of the new IEEE standards will affect the ease with which DER providers and customers can adopt increasing amounts of DERs and will minimize the need for distribution system infrastructure upgrades to accommodate those DERs. DER providers will need to continue to engage in the roll-out of these standards and in the decisions that commissions and utilities make about how to implement them.

Figure 9: 1547-2018 Update Process



Attachment B

PNNL-28113

Illinois Distributed Generation Rebate – Preliminary Stakeholder Input and Calculation Considerations

October 2018

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Executive Summary

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

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

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

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

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

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

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

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

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

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Acronyms and Abbreviations

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

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1.0 Introduction

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

1.1 Report Scope

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

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

1.2 Report Purpose

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

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

1.3 Context

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

1.3.1 Distributed Generation and Distributed Energy Resource

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

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

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

1.3.2 Context Interpretations

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

1.3.3 Investigation vs. Valuation

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

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

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

[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.

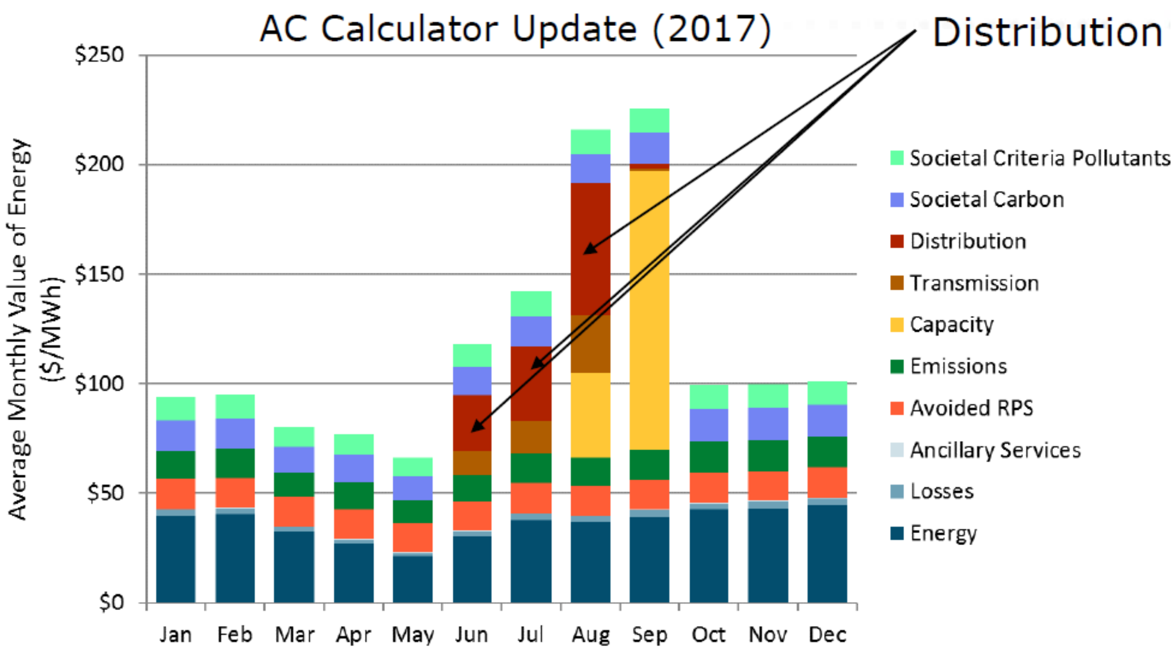

Figure 1. Average Monthly Value of Energy in California (E3 2017)

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.

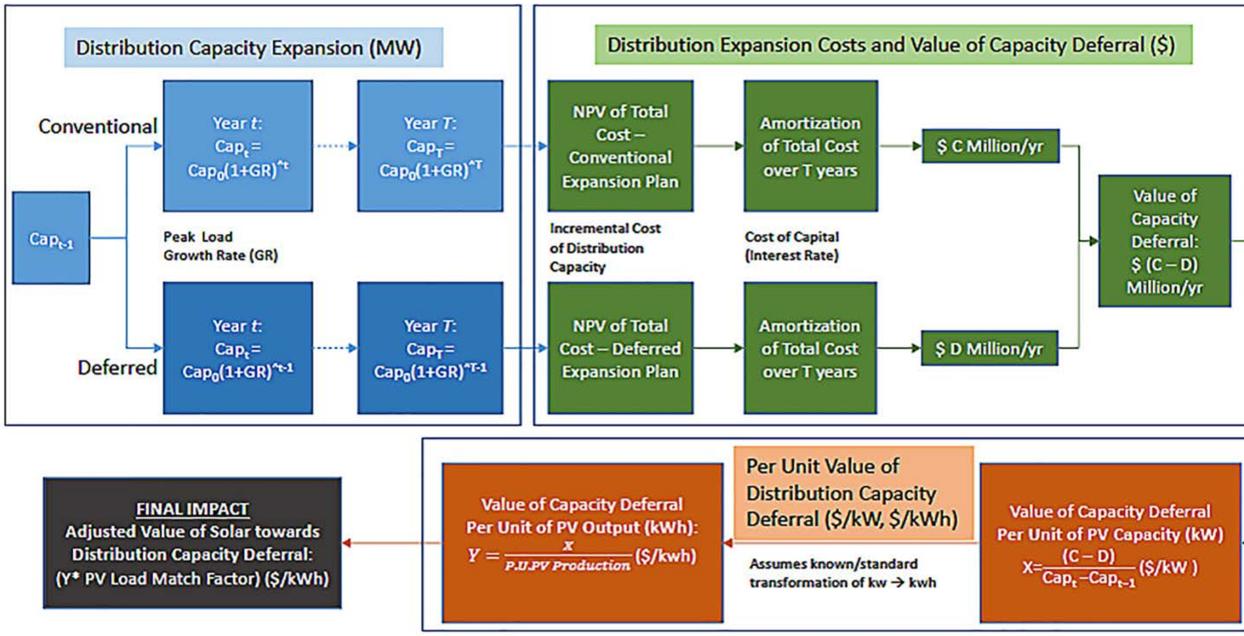

Figure 2. Minnesota Distribution Capacity Value Calculation

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]

<table>
<tr><th>Step</th><th>ConEdison Approach</th><th>National Grid Approach</th></tr>
<tr><td rowspan="2">Identification of Locational System Relief Value (LSRV) areas</td><td>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.</td><td>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.</td></tr>
<tr><td colspan="2">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.</td></tr>
<tr><td>Cap limiting the amount of DER capacity that may receive LSRV compensation</td><td>Amount of coincident relief that would reduce projected energy use to the point that usage falls below the threshold criteria.</td><td>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).</td></tr>
<tr><td>Calculation of LSRV and demand reduction value (DRV) rates</td><td>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.</td><td>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.</td></tr>
</table>

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

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

Appendix B

Minnesota VOS Tariff Avoided Distribution Capacity Cost Calculation Methodology

Appendix B

Minnesota VOS Tariff Avoided Distribution Capacity Cost Calculation Methodology

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

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

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

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

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

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

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

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

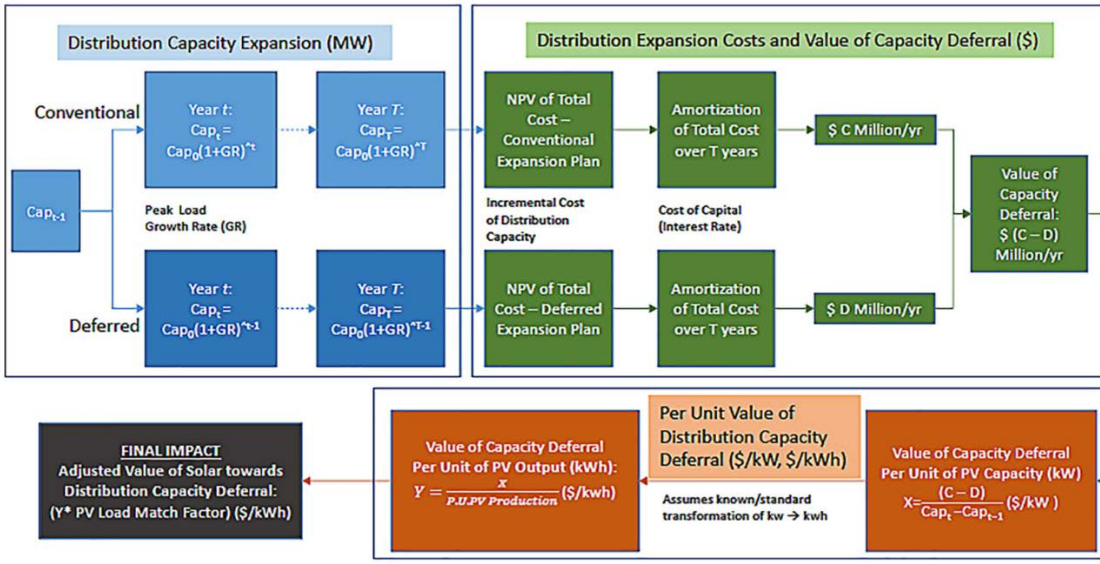

Figure B.1. Minnesota Distribution Capacity Value Calculation

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

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

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

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

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

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

Peak load reduction (PLR) is defined as

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

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

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

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

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

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

25 Year Levelized Value	Economic Value ($/kWh)	x	Load Match (No Losses) (%)	x	(1 +	Distributed Loss Savings (%)	)	=	Distributed PV Value ($/kWh)
Avoided Fuel Cost	E1					DLS-Energy			V1
Avoided Plant O&M - Fixed	E2		ELCC			DLS-ELCC			V2
Avoided Plant O&M - Variable	E3					DLS-Energy			V3
Avoided Gen Capacity Cos	cid:image001.png@01CF3783.2FA63960		ELCC			DLS-ELCC			V4
Avoided Reserve Capacity Cost	E5		ELCC			DLS-ELCC			V5
Avoided Trans. Capacity Cost	E6		ELCC			DLS-ELCC			V6
Avoided Dist. Capacity Cost	E7		PLR			DLS-PLR			V7
Avoided Environmental Cost	E8					DLS-Energy			V8
Avoided Voltage Control Cost									
Solar Integration Cost									
									Lev. VOS

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

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

Appendix C

Minnesota Valuation Components and Data Sources

Appendix C

Minnesota Valuation Components and Data Sources

Table C.1. Minnesota Valuation Components and Data Sources

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

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

Legislative Guidance	Basis	Value Component	Data Sources	Applicable Links and Resources	Notes
Required (delivery)	Capital cost of distribution	Avoided Distribution Capacity Cost	Standard PV degradation value	0.50%	
			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		
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		Applied to Avoided Generation Capacity Cost, Avoided Reserve Capacity Cost, Avoided Transmission Capacity Cost
			PTC Rating - California Energy Commission, or standard values provided by methodology	http://www.gosolarcalifornia.ca.gov/equipment/pv_modules.php	
			Inverter Efficiency Rating - California Energy Commission, or standard values provided by methodology	http://www.gosolarcalifornia.ca.gov/equipment/pv_modules.php	
			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	https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx	
Required (capacity)	Load Match Factor	Peak Load Reduction (no loss)	Utility		Applied to Avoided Distribution Capacity Cost
			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	http://www.gosolarcalifornia.ca.gov/equipment/pv_modules.php	
			Inverter Efficiency Rating - California Energy Commission, or standard values provided by methodology	http://www.gosolarcalifornia.ca.gov/equipment/pv_modules.php	
			Internal PV Array losses - measured or design		

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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