

INTEGRATED DISTRIBUTION PLANNING: GUIDANCE FOR UTILITY COMMISSIONS

Stakeholder Review Draft: April 15, 2019

ACKNOWLEDGMENTS

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

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In addition, the authors also thank the following individuals for providing peer review and comments on a draft version of the report:

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- Illinois Commerce Commission staff
- More to be added as comments are received

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, District of Columbia, Maryland, New Jersey and Pennsylvania, along with the U.S. Department of Energy (DOE), U.S. Environmental Protection Agency, 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 the Regulatory Assistance Project, with funding from 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.

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EXECUTIVE SUMMARY

To be drafted after stakeholder comments are received and body of report is revised, but before final draft is circulated for steering committee review and acceptance.

DRAFT

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)¹ 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, system operators, and regulators.

This manual is designed to assist utility commissions in the restructured jurisdictions that participate in the Mid-Atlantic Distributed Resources Initiative (MADRI)² with guiding and overseeing the development of Integrated Distribution Plans (IDPs) for electric utilities.³

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 Distributed Energy Resources (DERs)⁴ 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 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;
- A greater emphasis on reliability given the increased impacts of outages on customers and communities;
- A need for resilience at the distribution system level;

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 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.

² The participating jurisdictions are the District of Columbia (DC), Delaware (DE), Illinois (IL), Maryland (MD), New Jersey (NJ), Ohio (OH), and Pennsylvania (PA).

³ 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.

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.

- 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 automation, 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 taken a hands-off approach to 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.

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. A good plan will describe the existing distribution system; identify planned retirements and committed future additions of 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 the transforming 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 might 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 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.⁵ 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.

⁵ See, most importantly: EPRI. (2018). *Distribution Planning Guidebook for the Modern Grid*. 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.

There are numerous procedural options and decisions in terms of how a commission can structure its regulatory agenda with respect to distribution system planning. Some of the key procedural issues and options are discussed 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 which 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, while also optimizing the use of new resources and grid technologies.

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 would be necessary. Any necessary IDP legislation should be simple and germane to the Commission’s authority in order 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 (Investigation, Rulemaking, or Contested Case)

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. 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 this process becomes lengthy and slows progress towards the development of an actual 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 approved in an IDP proceeding.

An IDP can be viewed as analogous to a more formal integrated resource plan (IRP),⁶ 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. Developing some form of consistent framework that must be followed in each jurisdiction is important for several reasons. Stated requirements clearly communicate the Commission's expectations regarding the level of preparation and some thoroughness is expected of the utility in preparing the plan. Completed applications will then ensure that the Commission and stakeholders or intervenors receive the initial level of detail required to review a utility plan. Uniformity in utility filings also makes them easier for commission staff and stakeholders to review.

Some jurisdictions have promulgated regulations for IRPs, while others have opted for guidelines.⁷ Regulations are requirements that must be followed unless a waiver is sought and approved by the Commission. Guidelines are not enforceable in the same manner and 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 creates uniformity in utility filings, making it easier for commission staff and the public to review them.

⁶ 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.

⁷ 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. 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.

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 respect to its methodology for developing the plan and the scenarios and information it is considering.⁸ The benefit of a technical conference 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 roadmap 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 vs. Jurisdiction-Wide Planning

When it comes to evidentiary proceedings, as opposed to generic industry-wide procedures, commissions typically will proceed one utility and one case at 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 mergers have created “sister” utilities within one jurisdiction, such as in Maryland and Pennsylvania.

⁸ 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.

A joint proceeding involving other utilities could produce a more consistent statewide plan. 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.⁹

A regional approach may be difficult even though one holding company may have affiliates in multiple MADRI states. This is 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 goals). This means having the utility provide information that identifies areas on their 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, replacing equipment, or deploying new technologies, DERs, 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 ability to mitigate the need for utility investments. Moreover, an IDP should include a competitive bidding process that includes DERs to meet the needs of the grid, so that the best options (considering least-cost and least-risk objectives) are selected.

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 twenty 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

⁹ 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, the 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 the Commission's decisions drastically depart from past practices, they are 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).

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 integrate *resource* planning in US jurisdictions have examined a ten- to twenty-year planning horizon, with the plan updated every two to five years.¹⁰ 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 ten-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 not create 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 should 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.

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. The right to be heard is a fundamental principle of good governance. Stakeholder participation at every commission 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. IDP proceedings should be treated the same as other commission proceedings with the opportunity for full participation by all stakeholders.

¹⁰ Wilson, R. and Biewald, B. (2013). *Best Practices in Electric Utility Integrated Resource Planning*. Synapse Energy Economics for the Regulatory Assistance Project. Retrieved from <https://www.raponline.org/knowledge-center/best-practices-in-electric-utility-integrated-resource-planning/>

5. Binding or Non-Binding 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 information approach raises two concerns. First and fundamentally, the utility may not be required to file for approval in advance of their 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 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 information 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 pre-approving 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, etc.

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

This section will focus on IDPs considered under a contested case hearing procedure which requires commission approval.¹¹ 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 of a specific feeder based on distribution system attributes. Alternatively, in considering a cost benefit analysis¹² the Commission should 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 and

¹¹ 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 v. 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.

¹² 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.

environmental 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.

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, processes for further stakeholder engagement and future Commission review such as later cost recovery proceedings. 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. A modification may require an opportunity for party and stakeholder response and additional Commission review. In this situation the Commission should clearly outline the path forward and include 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 towards modifications which will satisfy the Commission. As with a modification, a denial which 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 their 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 pre-approve cost recovery of distribution assets before they are

used and useful in serving ratepayers.¹³ 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. 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 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 re-examining 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, and storage) 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 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 which is before the Commission for potential rate recovery.

¹³ 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 work in progress, in which case some limited cost recovery could be permitted in a rate case prior to the completion of the project.

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.¹⁴ 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.¹⁵ While 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. This argues for considering interconnection practices as part of an IDP. On the other hand, having a separate proceeding to examine interconnection practices 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?

¹⁴ The Federal Energy Regulatory Commission (FERC) has jurisdiction over rules for resources that interconnect to the interstate transmission grid.

¹⁵ K. Ardani, et al., A State-Level Comparison of Processes and Timelines for Distributed Photovoltaic Interconnection in the United States, National Renewable Energy Laboratory, p. 13 (January 2015).

- 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?
- 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?¹⁶
- Is there a pre-application report that allows DER customers to access (for a reasonable fee) a preliminary grid information report prior to submitting a full interconnection application?¹⁷
- 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)?
- 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?

¹⁶ Several states, including Ohio, Massachusetts, Illinois, Iowa, and California, have adopted this transparent supplemental review process. See *Priority Considerations for Interconnection Standards: A Quick Reference Guide for Utility Regulators*, Interstate Renewable Energy Council, p. 6 (August 2017), available at: <https://irecusa.org/priority-considerations-for-interconnection-standards/>.

¹⁷ Pre-application 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 Erica McConnell & Cathy Malina, *Knowledge is Power: Access to Grid Data Improves the Interconnection Experience for All*, Greentech Media (31 January 2017), available at: <https://www.greentechmedia.com/articles/read/knowledge-is-power-access-to-grid-data-and-improvesthe-interconnection-exp#gs.SVY9Tdw>; Zachary Peterson, *The State of Pre-Application Reports*, National Renewable Energy Laboratories (June 2017), available at: <https://www.nrel.gov/dgic/interconnectioninsights-2017-07.html>.

- Does the utility publish and make publicly available distribution system maps (i.e., heat maps, hosting capacity maps)?¹⁸
- 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.C.) 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)?
- 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, 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.

¹⁸ Hernandez, Mari, *New Grid Transparency Tools Improve Distributed Generation Siting*, Utility Dive, (26 June 2018), available at: <https://www.utilitydive.com/news/new-grid-transparency-tools-improve-distributed-generation-siting/526500/>

3. Consideration of Creating a Distribution System Operator

Some power sector stakeholders have suggested that the essential role of utilities, and the way they earn profits, could be transformed.¹⁹ 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.²⁰ 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 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."²¹

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 and remove some of the disincentives on the part of utilities to embrace the adoption of DERs. Having the utility operate as the DSO helps support the goal of changing utilities' motivations and business value proposition and better supports integrated operations. Finally, the utility has more comprehensive knowledge than any other party of real time system conditions across the entire distribution grid.

¹⁹ 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 at <https://energynews.us/2017/10/05/midwest/platform-model-will-be-key-for-illinois-future-power-grid/>.

²⁰ New York Public Service Commission, Case No. 14-M-010, Proceeding on the Motion of the Commission in Regard to Reforming the Energy Vision, Order Instituting Proceeding.

²¹ *Id.*, Order adopting Regulatory Policy Framework and Implementation Plan, February 26, 2015.

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 proper incentives, 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.²²

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. 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 Model and Ratemaking Issues

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 its investors through a return on its rate base which consists largely of its 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 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.⁴ The objective of PBR is to better align the utility's interest with the 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

²² Migden-Ostrander, J. (2015, December). Power Sector Reform: Codes of Conduct for the Future. *The Electricity Journal*, 28(10), 69-79. Retrieved from <https://www.sciencedirect.com/science/article/pii/S1040619015002274>

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.²³

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 performance-based regulation (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.²⁴ 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 incent 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; 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.

²³ 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.

²⁴ 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.

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 more costly 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 EDU (or an aggregator), would be extremely beneficial.

When working on DER 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 DER 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 megawatt-hours or MWh) to an impact on the peak load forecast (measured in megawatts or MW).

The accuracy of both real-time and long-term load forecasting methods would be improved with greater visibility into the behind the meter solar installations, including historical output, location, and planned deployments. Additionally, any ability to receive telemetered output data

(even aggregated data) through coordination with EDUs 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. Commissions should 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 A to this guidance document.

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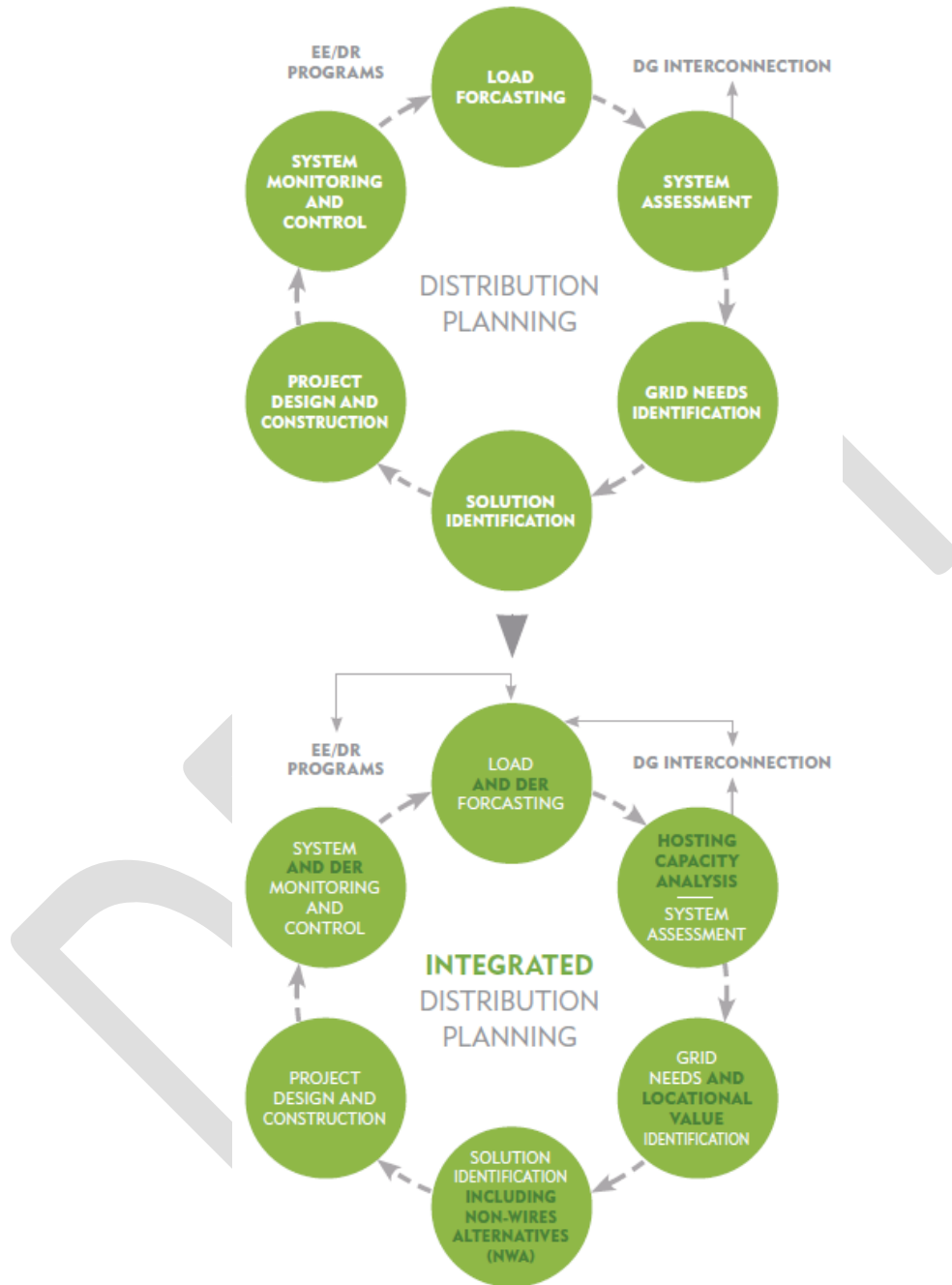
III. PROCESS FOR DEVELOPING AN IDP

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 pre-construction regulatory approval.

Regulatory commissions that adopt a formal IDP requirement will in most cases want to prescribe, or at least outline, a *process* for the development of such plans by utilities and for more rigorous oversight by the Commission. 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 1 below illustrates how a typical distribution planning process, shown at the top of the figure, compares to an IDP process as shown on the bottom of the figure.

Figure 1: Comparison of Typical Distribution Planning Process and IDP²⁵



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

²⁵ Volkmann, Curt. (2018). *Integrated Distribution Planning: A Path Forward*. GridLab. Downloaded from <https://gridlab.org/publications/>.

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 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. Department of Energy report, *Modern Distribution Grid, Volume II: Advanced Technology Maturity Assessment*, provides a helpful framework for identifying technology needs for IDP planning.²⁶

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. By net load, we mean the gross customer demand for electricity minus any portion of that demand that will be served by behind-the-meter DERs. This 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 forecast DER adoption trends. 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.

The hallmark of an IDP process is granularity. The forecasts will need to be spatially and temporally granular to enable a proper assessment of system needs and potential solutions. 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. One aspect of an

²⁶ US Department of Energy. (2017.) *Modern Distribution Grid, Volume II: Advanced Technology Maturity Assessment*. Available at: https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-II_v1_1.pdf.

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 is discussed in greater detail in Section IV.C.) 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. At the same time, this analysis can also identify locations where deployment of additional DERs or traditional assets would have the greatest value. 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 identify options to resolve system constraints. Power flow analysis software will contain the following capabilities:

- Peak Capacity Planning Study;
- 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; and
- 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; and
- 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; and
- 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 toolkits 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.

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 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 or energy storage, where such investments are not precluded by state policies or regulations;
- Customer and third-party investments in DG, energy storage, and other behind-the-meter technologies; and
- Retail rate designs that encourage customers to shift or reduce their peak demand.²⁷

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. Utilities may benefit from engaging outside experts in the characterization of some options, and commissions should 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.

Some states may wish to employ an iterative approach to selecting solutions, 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 or the Commission could issue a request for proposals (RFP) to solicit competitive bids.

²⁷ Appendix B offers examples that illustrate some of the ways DERs have been beneficially used by utilities and/or grid operators to meet distribution system needs.

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.

The final written IDP will cover all the steps up to this point. It will summarize the net load forecast, capabilities of the existing system, projected future needs, options, and preferred solutions to identified needs. Regulatory commissions will need to decide before the planning process begins whether and how to engage stakeholders and the public in review of the plan, and whether the Commission itself will formally approve the IDP or merely acknowledge that the plan and the planning process meet all legal requirements – unless these decisions are already specified in statutes mandating a prescribed IDP process.

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 pre-construction approvals from the PUC, 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.

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 cross-arm, steel towers, concrete pads); 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;
- 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 non-coincident 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 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 the service territory;

- Number and capacity of public EV charging stations;
- Number and capabilities of any islandable microgrids;
- Recent history of investment in demand side management (EE and DR) and results (energy and demand savings);
- 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 should 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, categorized by reason for investment. This should include planned infrastructure projects, 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.

C. 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. 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.²⁸ 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 other tools and approaches that should be considered and deployed to optimize DERs on the grid, including, but not limited 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.²⁹

²⁸Stanfield, Sky, S. Safdi, & S. Baldwin Auck. *Optimizing the Grid: A Regulator’s Guide to Hosting Capacity Analyses for Distributed Energy Resources*, Interstate Renewable Energy Council, p. 3 (December 2017), available at: <https://irecusa.org/publications/optimizing-the-grid-regulators-guide-to-hosting-capacity-analyses-for-distributed-energy-resources/> (“*Optimizing the Grid*”)

²⁹ *Optimizing the Grid* at 13-14; and Homer, Juliet (Pacific Northwest National Laboratory), A. Cooke (Pacific Northwest National Laboratory), L. Schwartz (Lawrence Berkeley National Laboratory), G. Leventis (Lawrence Berkeley National Laboratory), F. Flores-Espino (National Renewable Energy Laboratory), and M. Coddington (National Renewable Energy Laboratory), *State Engagement in Electric Distribution System Planning (Executive Summary)*, pp. iii-v (December 2017), available at: <https://emp.lbl.gov/publications/state-engagement-electric> (“*State Engagement in Electric Distribution Planning*”)

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.³⁰ 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 granular 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.

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 requiring regulated utilities to deploy HCA, including California, Hawaii, Minnesota, New York, and Nevada, with most working actively to integrate HCA into IDP.³¹ Others are in the early stages of exploring HCA, such as Colorado, Maryland, and the District of Columbia.³² Additionally, several utilities are deploying HCA outside of the context of more formal state requirements, including Commonwealth Edison (ComEd) in Illinois and Pepco Holdings, Inc., which owns several utilities in other MADRI jurisdictions.³³ 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

³⁰ For helpful references, refer to two publicly-available EPRI publications: 1) EPRI. (2018). *Impact Factors, Methods, and Considerations for Calculating and Applying Hosting Capacity*. Available at: <https://www.epri.com/#/pages/product/000000003002011009/?lang=en>. 2) EPRI. (2016). *Integration of Hosting Capacity Analysis into Distribution Planning Tools*. Available at: <https://www.epri.com/#/pages/product/3002005793/?lang=en-US>.

³¹ *State Engagement in Electric Distribution Planning* at iv; and Nevada Public Service Commission Docket No. 17-08022 Investigation and Rulemaking to Implement Senate Bill 146 (2017); and New York Joint Utilities, Case 16-M-0411, Supplemental Distributed System Implementation Plan, p. 49 (1 November 2016).

³² See: Colorado Public Utilities Commission Docket 17M-0694E Review Of ERP, RES and Integration Rules; Maryland Public Service Commission Docket PC 44 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; and Public Service Commission of the District of Columbia Docket FC1130 Modernizing Energy Delivery Structure.

³³ *Optimizing the Grid* at 41-42; and Pepco Hosting Capacity Map, available at: <https://www.pepco.com/MyAccount/MyService/Pages/MD/HostingCapacityMap.aspx>.

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).³⁴

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 should 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/she ensure effective and neutral reporting of stakeholder input and outcomes?
- What is the timeline for the process?
- 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 non-utility 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 key information.

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

³⁴ E.g., Case Studies for California, New York, Minnesota and Pepco Holdings Co., Inc. (*Optimizing the Grid* at 32-42); and *State Engagement in Electric Distribution Planning*.

their performance characteristics.³⁵ Regulators overseeing and guiding IDP efforts should be aware of and familiar with the distinctions and tradeoffs between and 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?
- 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?
- Will the HCA be developed in phases? If so, what will each phase address?³⁶
- If developed in phases, how will the HCA be scaled over time (i.e., 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 should 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

³⁵ Optimizing the Grid at 5-6.

³⁶ For example, in the Nevada Public Service Commission Docket No. 17-08022, Investigation and rulemaking to implement Senate Bill 146 (2017), the 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 Nevada Public Service Commission Docket No. 17-08022, Investigation and Rulemaking to Implement Senate Bill 146 (2017); and the New York utilities proposed a four stage HCA roadmap, with each subsequent stage increasing in effectiveness, complexity, and data requirements. See New York Joint Utilities, Case 16-M-0411, Supplemental Distributed System Implementation Plan, p. 49 (1 November 2016).

planning use case goals. Regulators should consider requesting 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., entire system, high priority portions, incremental expansion over time, etc.)?³⁷
- What types of DERs will be modeled (i.e., DG, energy storage, EVs, or all DERs)?
- Is the HCA technology neutral?³⁸
- How will HCA data be published and displayed on system maps?
 - What kind of color-coding will be required on system maps?
 - 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? (e.g., 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?
- Will the underlying data be publicly accessible?
 - How will the underlying data be shared (e.g., through downloadable and sortable data files or in a machine query-able format)?
 - 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.)?³⁹
- How will HCA results be validated over time?

³⁷ “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.” See *Optimizing the Grid* at 21.

³⁸ 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 Pacific Gas & Electric Co., R. 14-08-013, Pacific Gas & Electric Company’s (U 39 E) Demonstration Projects A & B Final Reports, Appendix A (Demonstration Project A— Enhanced Integration Capacity Analysis, p. 16 (Dec. 27, 2016)); New York and Minnesota are just focusing on solar of a certain scale in their initial analysis. See: New York Public Service Commission, Case 16-M-0411, Order on Distributed System Implementation Plan Filings, pp. 10-15 (Mar. 9, 2017) and Xcel Distribution System Study at pp. 3-4, 6 (focusing HCA analysis on small-scale DG technologies); Xcel Energy, Dkt. E002/M-15-962, Supplemental Comments: Biennial Distribution Grid Modernization Report, pp. 9, 11 (Mar. 20, 2017) (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).

³⁹ 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 *Optimizing the Grid* at 20.

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.

D. Load and DER Forecast

The IDP report should include a load forecast 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. The report should also describe the methods, data sources, and models used to develop these forecasts. Load forecasts can then be combined with DER forecasts to develop net load 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 might have little or no impact on energy but significantly change 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 developed may be superseded by the time the IDP is updated.⁴⁰

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.

E. Needs Assessment/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

⁴⁰ 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*. Lawrence Berkeley National Laboratory. Downloaded 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. Downloaded from <https://www.cleanpower.com/2018/forecast-der-adoption/>. 3) Interstate Renewable Energy Council. (2018). *Cornerstone for Next Generation Grid Activities: Forecasting DER Growth*. Downloaded from <https://irecusa.org/2018/02/cornerstone-for-next-generation-grid-activities-forecasting-der-growth-2/>.

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 been given targets (sometimes associated with performance incentives) by 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 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.

In addition to minimum design criteria, there may be more ambitious related goals. For example, planners might adopt a firm limit for deviations from nominal voltage at the customer’s meter to plus or minus five percent, while adopting a *goal* of limiting imbalances on feeder circuits to plus or minus three percent. Another criterion that might be used is to limit the loading on feeder circuits to some percentage (e.g., 75 percent) of rated capacity under normal conditions to allow for switching of load from other feeders in the case of N-1 contingencies.

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 and 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, etc. In most of the U.S., the amount of line sag is greatest on very hot summer late 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 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-build-up 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 3 to 6 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, 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.
- 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.

As noted above, 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, 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

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. In the traditional 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, or 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, and EE. Changes in rate design which affect peak demand may also be considered. The goal remains to find the least costly 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.

The IDP report should describe the assumed capabilities and costs of each option category considered. The evaluation of options generally assumes that utilities can purchase as many traditional assets as are needed to solve a distribution system problem; however, because the adoption of customer-owned or third-party owned DERs is not unlimited, planners may need to assess the amount of DERs that might reasonably be deployed in time to meet identified needs. 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. 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). If the IDP process used a range of assumed values or assessed multiple scenarios, the report should also explain how the preferred solutions were selected in cases where the least costly option varied depending on assumptions or varied across scenarios.

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 implementation actions that need to be performed in the near term, e.g. during 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 planning and investment decisions for the distribution system.

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 should rule on the Action Plan, with the options to approve, disapprove or modify the Plan, which then becomes the guiding roadmap 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 should 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 of 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.

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V. CHALLENGES FOR DEVELOPING AND IMPLEMENTING AN IDP

The process of developing an IDP raises new challenges for everyone involved. In this section, we will 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 in order 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 towards those goals.

Commissions should make sure they have the right staff capacity and expertise to oversee and implement an 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.

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 should make sure this transition is orderly, leads to benefits for the grid, and is not retroactively punitive.

There are two important aspects to DER implementation and compensation. First, 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. The second issue is that DERs ought to be compensated based on value to the grid. The goal is a fair and equitable resolution such that there are no rate subsidies either for the DER provider or the utility

ratepayers. While some DER adoption might come through a utility planning process, much of the DER deployment will fall outside the utility's control as customers make choices about their energy use and installing DERs. In either case, the goal of setting rates and compensation ought to be to ensure that 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. This is where establishing good rate designs becomes important.

1. Rate Design

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 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 the grid.

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 (LMPs) 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 resources to meet projected peak demand, also vary by location, season, 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.

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 load serving entities 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 industrial 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 1 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 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 1: 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.

2. 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 for utility commissions 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.

Utility commissions across the country have most commonly addressed DER compensation through net energy metering (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, the National Association of Regulatory Utility Commissioners (NARUC) published a comprehensive reference on DER rate design and compensation approaches in 2016 (hereafter, the “NARUC Manual”).⁴¹

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.”⁴²

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 4th Report from Lawrence Berkeley National Laboratory’s Future Electric Utility Regulation (FEUR) series, *Distribution System Pricing with Distributed Energy Resources*,⁴³ the authors used as a starting point 24 smart inverter functions described in an EPRI technical report.⁴⁴

⁴¹ NARUC Staff Subcommittee on Rate Design. (2016). *Distributed Energy Resources Rate Design and Compensation*. Washington, DC: The National Association of Regulatory Utility Commissioners. Available at: <https://www.naruc.org/rate-design/>.

⁴² NARUC Manual at page 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 a 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.”

⁴³ Hledik, R. and Lazar, J. (2016). *Distribution System Pricing with Distributed Energy Resources*. LBNL-1005180. Retrieved from <https://emp.lbl.gov/publications/distribution-system-pricing>

⁴⁴ EPRI has since updated its report on smart inverter functions: EPRI. (2016). *Common Functions for Smart Inverters: 4th Edition*. Retrieved from <https://www.epri.com/#/pages/product/3002008217/?lang=en-US>

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:

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.⁴⁵

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 their 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. 4.⁴⁶ 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 bi-lateral 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.

Commissions also need to look at the environment that DER will be deployed in and make sure that current rules do not unduly hamper DER growth. 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. Third party ownership of

⁴⁵ NARUC Staff Subcommittee on Rate Design. (2016). *Distributed Energy Resources Rate Design and Compensation*. Washington, DC: The National Association of Regulatory Utility Commissioners. Available at: <https://www.naruc.org/rate-design/>.

⁴⁶ Hledik, R. and Lazar, J. (2016). *Distribution System Pricing with Distributed Energy Resources*. LBNL-1005180. Retrieved from <https://emp.lbl.gov/publications/distribution-system-pricing>

rooftop PV is one example of many of the 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 PV. Another indicative example would be legacy statutes that treat residential customers with rooftop PV the same as a large and sophisticated corporate generator.

3. State Rules that Prohibit/Inhibit DER Deployment

Existing administrative rules should also be examined to see if any of them are unduly working against healthy DER deployment. Interconnection rules are an 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 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 capacity maps that allow them to see where DERs are needed and where additional capacity investments might be required.

Commissions should 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 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/Ownership

It is crucial that the privacy of customer-specific data be protected with modern cyber security best practices. Commissions should 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. This is a complicated topic but a customer owning their data seems like an effective protection. However, what is probably most important, regardless of whether customer data ownership makes sense for one jurisdiction or another, is that customers have the same protections, access, and ability to share their data as if they owned it.

This includes a safe way to share their 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*.⁴⁷ Some are also looking to include other standards, such as OpenID used by banks. Data privacy and security best practices do not require a utility to prohibit or needlessly complicate a customer sharing their data, regardless of ownership.

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 anonymized 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 written 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 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

⁴⁷ For more information on the Green Button Program, go to <http://www.greenbuttondata.org/>.

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.

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 compare 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.⁴⁸
- **Interconnection data and DER databases:** Frequent tracking of interconnection applications and databases of existing DER on the grid 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 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 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, 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.⁴⁹

⁴⁸ 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/>.

⁴⁹ Lydic, Brian, Smart Inverter Update: New IEEE 1547 Standards and State Implementation Efforts, Interstate Renewable Energy Council, (23 July 2018), available at: <https://irecusa.org/2018/07/smart-inverter-update-new-ieee-1547-standards-and-state-implementation-efforts/>

- **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 (and, alternatively, foregoing such investigations may limit the accuracy of an IDP).
- **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.⁵⁰
- **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 these 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),⁵¹ 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

⁵⁰ McConnell, E. and Johnson, A. (2018). *Cornerstone for Next Generation Grid Activities Forecasting DER Growth*. Interstate Renewable Energy Council. Available at: <https://irecusa.org/2018/02/cornerstone-for-next-generation-grid-activities-forecasting-der-growth/>.

⁵¹ 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.

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. 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, i.e., 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.⁵² Fortunately, practical solutions for addressing the throughput incentive exist.

One option is to use smart rate designs to properly compensate owners of DERs and minimize lost revenue problems. With that goal in mind, in February 2016, the Regulatory Assistance Project (RAP) prepared a report at the request of the MADRI Steering Committee on designing tariffs for customers with DG.⁵³ NARUC later published its comprehensive reference on this topic, previously noted (which cites the MADRI paper on designing tariffs as well as many other resources).⁵⁴ 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 non-residential customers.⁵⁵

Another common approach to addressing the throughput incentive involves revenue regulation, also known as revenue “decoupling.” Under revenue decoupling, the Commission establishes the

⁵² See for example: National Action Plan for Energy Efficiency. (2007). *Aligning Utility Incentives with Investment in Energy Efficiency*. Prepared by Val R. Jensen, ICF International. Available at: <https://www.epa.gov/sites/production/files/2015-08/documents/incentives.pdf>.

⁵³ Migden-Ostrander, J., and Shenot, J. (2016). *Designing Tariffs for Distributed Generation Customers*. Montpelier, VT: Regulatory Assistance Project. Available at: <https://www.raponline.org/knowledge-center/designing-tariffs-for-distributed-generation-customers/>.

⁵⁴ NARUC Staff Subcommittee on Rate Design. (2016). *Distributed Energy Resources Rate Design and Compensation*. Washington, DC: The National Association of Regulatory Utility Commissioners. Available at: <https://www.naruc.org/rate-design/>.

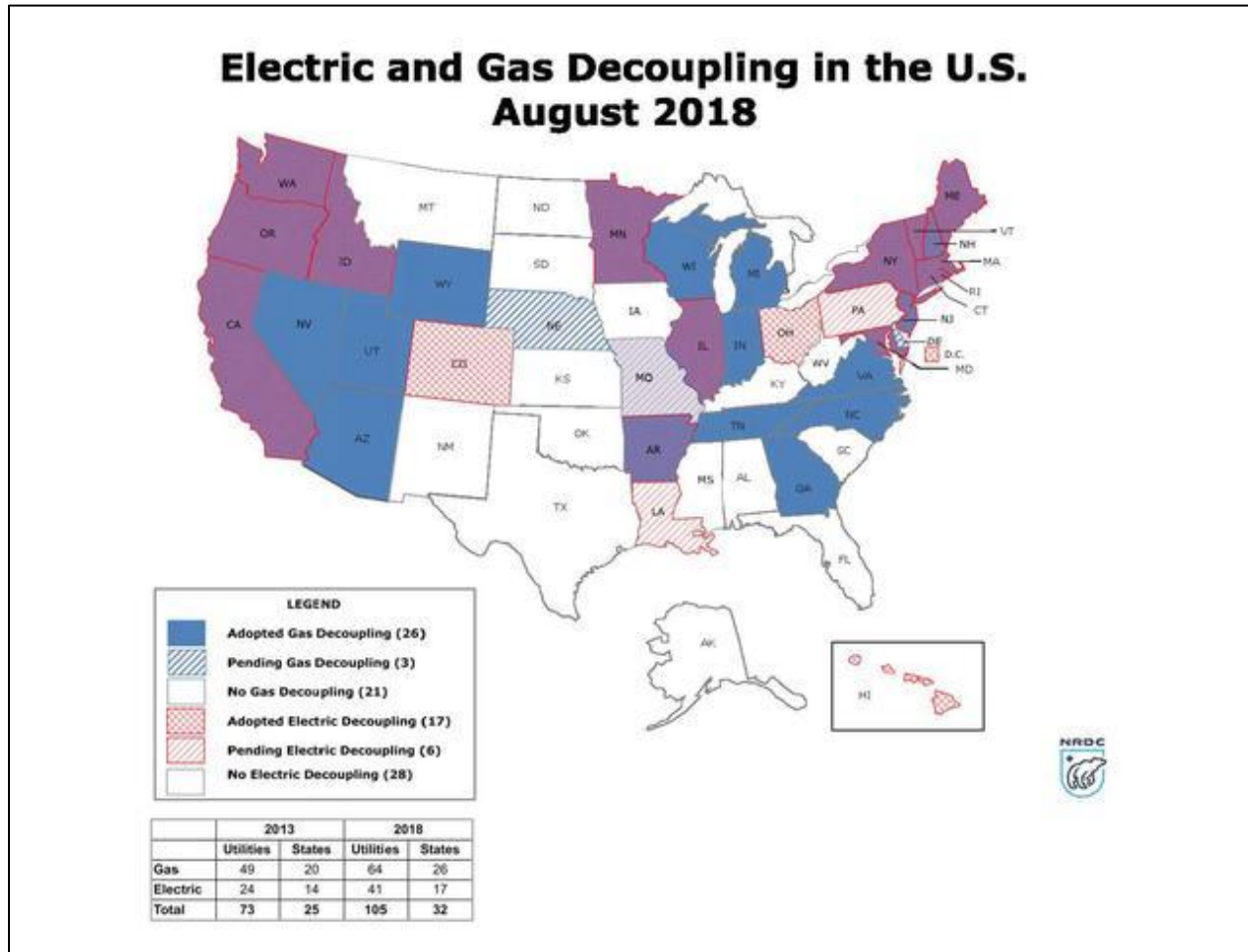
⁵⁵ See: 1) Lazar and Gonzalez. (2013). *Smart Rate Design for a Smart Future*. Regulatory Assistance Project. <https://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/>. 2) Linvill et al. (2017). *Smart Non-Residential Rate Design*. Regulatory Assistance Project. <https://www.raponline.org/knowledge-center/smart-non-residential-rate-design/>.

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.⁵⁶ In May 2006, a MADRI working group developed and published a Revenue Stability Model Rate Rider at the request of the MADRI Steering Committee.⁵⁷ 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 2.

⁵⁶ RAP produced two useful references on this topic, the first being a guide to theory and the second being a manual for designing decoupling mechanisms: 1) Regulatory Assistance Project. (2016). *Revenue Regulation and Decoupling: A Guide to Theory and Application*. Montpelier, VT: Regulatory Assistance Project. Available at: <https://www.raponline.org/knowledge-center/revenue-regulation-and-decoupling-a-guide-to-theory-and-application-incl-case-studies/>. 2) Migden-Ostrander, J., and Sedano, R. (2016). *Decoupling Design: Customizing Revenue Regulation to Your State's Priorities*. Montpelier, VT: Regulatory Assistance Project. Available at: <http://www.raponline.org/knowledge-center/decouplingdesign-customizing-revenue-regulation-state-priorities>.

⁵⁷ 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 2: Status of Decoupling Policies in the US⁵⁸



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 utility earnings. This creates a utility investment preference for

⁵⁸ Natural Resources Defense Council. (2018). Downloaded January 21, 2019 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.”⁵⁹

A second but related cause of capital bias occurs when the regulated rate of return is set above the utilities’ true cost of capital. This creates a financial “value engine” that rewards shareholders for expanding capital base.⁶⁰

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.⁶¹ The Illinois Commerce Commission has initiated a rulemaking to allow utilities to ratebase investments in cloud-computing software, if it reduces total costs, as an option to address the capital bias in one area of utility investment.⁶²

Performance Based Regulation (PBR) offers another option for addressing capital bias and aligning utility shareholder interests with least-cost IDP solutions.⁶³ PBR consists of a suite of tools that regulators can mix and match to best suit the needs and norms of their jurisdiction.

⁵⁹ 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. (1962). *Behavior of the Firm Under Regulatory Constraint*. American Economic Review. 52 (5): 1052–1069. JSTOR 1812181.

⁶⁰ This second cause of capital bias is explained in detail in: Kihm, S. et al. (2015). *You Get What You Pay For: Moving Toward Value in Utility Compensation*. America’s Power Plan. Available at: <https://americaspowerplan.com/wp-content/uploads/2016/07/CostValue-Part1-Revenue.pdf>.

⁶¹ This option is discussed in: Advanced Energy Economy, June 2018. *Optimizing Capital and Services Expenditures: Providing Utilities with Financial Incentives for a Changing Grid*. Available at: <https://info.aee.net/hubfs/PDF/Opex-Capex.pdf>.

⁶² Illinois Commerce Commission on its Own Motion Initiating Proposed Rulemaking Relating to the Regulatory Accounting Treatment of Cloud-Based Solutions. Case No. 17-0855. Available: <https://www.icc.illinois.gov/docket/CaseDetails.aspx?no=17-0855>.

⁶³ Two recent publications on performance-based regulation may be helpful. 1) 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. Available at: <http://eta-publications.lbl.gov/sites/default/files/lbnl-1004130.pdf>. 2) 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. Available at: <https://www.nrel.gov/docs/fy17osti/68512.pdf>.

The most common approach to PBR worldwide is the multi-year 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, potentially paired with revenue decoupling, automatically adjusts rates or the revenue requirement in between rate cases using forecasts or indexed trends to predict future utility costs. This is considered a form of PBR 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 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.⁶⁴ However, there is also a possibility that investments in the distribution 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.

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 and 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 will need some assurance that they will 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 potentially more expensive, utility-owned solution. One option is to add language to a standard interconnection contract that sets forth the obligations of the DER to provide the visibility needed. 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 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.⁶⁵

⁶⁴ 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 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.

⁶⁵ Migden-Ostrander, J. (2015, December). Power Sector Reform: Codes of Conduct for the Future. *The Electricity Journal*, 28(10), 69-79. Retrieved from <https://www.sciencedirect.com/science/article/pii/S1040619015002274>

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.⁶⁶ 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 back-up 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

Customers who are interested in owning or hosting DERs face their own set of challenges, relating to education, equity, access to financial products, physical limitations, and other issues. These challenges can make it difficult for an IDP to identify and execute the best, least-cost DER portfolio. A fundamental challenge for customer adoption of DERs is that it is frequently difficult to determine if compensation for customer-sited DERs is adequate and fair. Customers will install DERs if they provide value through bill savings or other revenue streams that exceed installation and operational costs but currently it is a challenge for customers (and DER providers) to determine the total value proposition that DERs will provide.⁶⁷

1. Customer Education, Engagement, and Acceptance

Customer education and engagement is 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.

⁶⁶[https://webapp.psc.state.md.us/newIntranet/Casenum/NewIndex3_VOpenFile.cfm?filepath=C:\AdminDocket\PublicConferences\PC44\172\PC44-Letter2\(Attachment1\)-StorageWorkingGroupprogramproposal.pdf](https://webapp.psc.state.md.us/newIntranet/Casenum/NewIndex3_VOpenFile.cfm?filepath=C:\AdminDocket\PublicConferences\PC44\172\PC44-Letter2(Attachment1)-StorageWorkingGroupprogramproposal.pdf)

⁶⁷ This issue of customer compensation is more thoroughly discussed in section V.D.1. since it is as much of a challenge for DER providers as it is for customers.

Studies show that a large majority of customers care about clean energy and a sizeable minority would be willing to pay a premium for clean energy resources. But still, a lack of information and engagement prevents many customers from acting on these stated preferences and adopting DERs. 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), and non-government organizations. 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 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 that 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 ITC and the EV Tax Credit, are non-refundable, 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 in order 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.

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 multi-family 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. These conditions may prevent installers from installing DERs, such as EE. Studies show that fifteen percent of low-income homes have health and safety issues that prevent providers from delivering weatherization services.

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.

1. Customer Compensation for DERs

The biggest challenge for DER providers is ensuring that compensation for customers is adequate and fair. Customers will install DERs if they provide value through bill savings or other revenue streams that exceed installation and operational costs.

Some of the important reasons for implementing an IDP is to increase grid efficiency and optimize the resources distributed on the grid. Recognizing the full value that the resources provide to the grid and thus encouraging more investment by customers and third parties is a vital part of any effort.

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 for customers and DER providers is in assessing the potential revenue streams and determining the total value proposition that DERs will provide.

i. Tariffs or Bill Credits

Customers with DERs can be directly or indirectly compensated by their utility via their utility bill. To begin with, the rate design and the prices in a traditional utility tariff create an inherent value and compensation to the customer for any action that reduces billing determinants. When a customer reduces their energy consumption, the utility avoids energy costs and potentially some other costs, and the customer pays less on their bill. When a customer on a demand rate reduces their on-peak demand, the utility potentially avoids capacity costs and the customer is compensated through a reduction in their utility bill. Thus, even a “traditional” retail rate design will partially compensate DER owners for the values they provide to the utility system. The amount of compensation, however, may bear little resemblance to the value provided.

Many utilities also offer tariffs, bill credits, or rebates that more accurately compensate customers for the value of DERs – and especially DR actions. These include real-time pricing, critical peak pricing, variable peak pricing, other TOU rates, and peak time rebates (PTR). Each of these tariffs recognizes that utility system costs vary with time and sends a price signal that consumption during peak hours is much costlier than at other times (or conversely, actions that reduce demand during peak hours are much more valuable than similar actions taken off peak). In other words, these time-varying rate designs better align customer compensation with utility system avoided costs (value) than a traditional rate design.

Almost all utilities offer special tariffs to customers with PV or other forms of DG. The most common of these are NEM and net energy billing tariffs. A relatively small number of utilities instead (or additionally) offer Value of Solar tariffs (an example of a Value of Resource tariff), feed-in tariffs (FITs), or community solar programs that provide bill credits to participating customers. In each such case, the utility or its relevant regulatory authority decided when it created the tariff or community solar program how much credit customers should receive on their bill for each kWh of generation from the DG system. In many cases, these decisions have been informed by an investigation into the streams of value that a DG system typically provides to the utility. A Value of Service tariff is explicitly designed to offer compensation that reflects system value, whereas a FIT (which is only rarely available in the US) is usually designed to incentivize DG installations by offering compensation that exceeds the customer’s costs, regardless of utility system value. NEM and net energy billing tariffs are generally designed to be simple; they offer credit at the customer’s retail energy rate for every kWh the customer generates and consumes. However, NEM and net energy billing tariffs will also specify how much credit the customer receives for net excess generation (i.e., generation during a billing period that exceeds consumption during the billing period), and that credit is often set at a level intended to compensate the customer for specific value streams. Each type of DG tariff will also specify whether the customer or the utility takes ownership of any renewable energy certificates (RECs⁶⁸); if it is the utility, the compensation afforded to the customer may reflect this additional value.

⁶⁸ Renewable energy certificates (or credits) are used to demonstrate compliance with a state renewable portfolio standard or to substantiate claims regarding the voluntary purchase of renewable electricity. A REC represents the renewable and environmental “attributes” associated with one megawatt-hour of electricity generated by an eligible resource. Eligibility of resources varies from state to state.

These traditional compensation mechanisms are changing as the adoption of DERs, and in particular the adoption of distributed solar, increases. For example, in March 2017, the New York Public Service Commission (NY PSC) issued an order that broke new ground for compensating DERs for the values they provide to the utility system. In that order, the NY PSC reached a critically important conclusion that is undoubtedly applicable in many jurisdictions:

“The Commission also recognizes that existing DER business models are well-established and based largely on net energy metering (NEM). These business models reflect the capabilities and needs of the electric system at the time they were designed and they appropriately served to open up markets and drive initial development. But such business models and NEM in particular are inaccurate mechanisms of the past that operate as blunt instruments to obscure value and are incapable of taking into account locational, environmental, and temporal values of projects. By failing to accurately reflect the values provided by and to the DER they compensate, these mechanisms will neither encourage the high level of DER development necessary for developing a clean, distributed grid nor incentivize the location, design, and operation of DER in a way that maximizes overall value to all utility customers. As such, they are unsustainable.”

ii. Market Revenues

The seven ISOs existing in the US today operate wholesale markets for electricity services in which various market participants compete to provide energy, capacity, and ancillary services to load-serving entities (utilities and competitive retail energy suppliers). 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.

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.⁶⁹ 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.⁷⁰

⁶⁹ Refer to: <https://www.ferc.gov/whats-new/comm-meet/2018/021518/E-1.pdf>.

⁷⁰ FERC Order 841, paragraph 29.

Additionally, in a 2017 Policy Statement,⁷¹ FERC clarified that energy storage resources can look to recover their costs through both cost-based rates (i.e. ratebase) and market-based rates concurrently. This means that energy storage assets used as NWAs can 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.

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 distribution system operator (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.

PV and other DG resources may also be able to capture monetary value by participating in REC trading markets.

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.

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.

2. Aggregation of Small DERs

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

⁷¹ FERC, Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery. January 19,

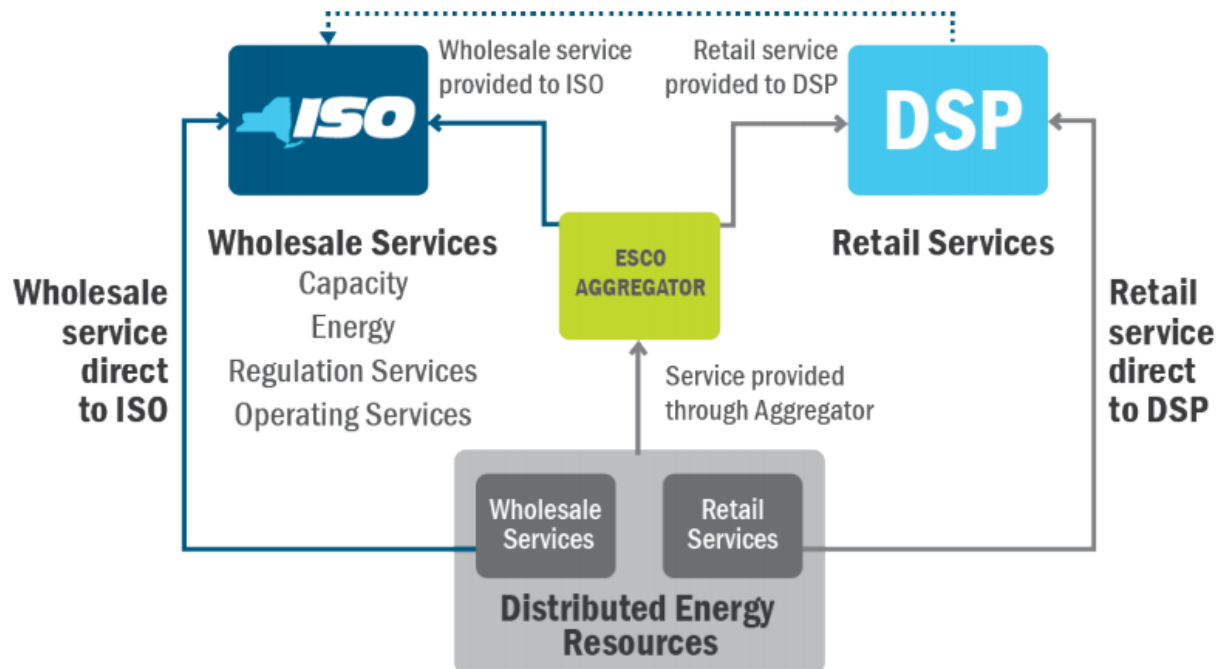
opportunity to aggregate different DERs to provide a wider range of energy and grid services. Distributed solar, storage, EVs, and targeted EE and DR can have a significant impact on the grid and have the potential of providing valuable services that obviate the need for distribution, transmission and 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.

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 the Federal Energy Regulatory Commission 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 3 below provides an overview of NYISO’s vision for DER participation based on their ability to receive and implement dispatch signals that are driven by reliability or economics.

Figure 3: NYISO Vision for DER Participation⁷²



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. Due to 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.⁷³
- **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 NEM interconnections on the distribution utility's system. DERs that have gained approval through the utility's NEM process have to undergo a separate wholesale interconnection approval process. This process should be streamlined as the market evolves.
- **Metering Requirement** – ISOs are applying the same metering and telemetry requirements for DERs as for traditional generators. The requirement of installing

⁷²

http://www.nyiso.com/public/webdocs/markets_operations/market_data/demand_response/DER_Roadmap/DER_Roadmap/Distributed-Energy-Resources-2017-Market-Design-Concept-Proposal.pdf

⁷³ 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.

revenue recording meters for energy production and consumption along with the requirement to transmit data at short time intervals (such as 1 minute) is cost prohibitive for smaller DERs.

- **Wholesale/Retail Market Boundary** – The definition of jurisdictional and technical boundaries for monitoring, control, visibility, and oversight between 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 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.

3. Coordination between Utilities and DER Providers

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 roadmap 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.⁷⁴ Some of the recommendations have also been utilized by IEEE in their IEEE 1547 standards update which will eventually make its way to multiple jurisdictions in the next few years.

⁷⁴ <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 4 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 4: DER Communication Landscape⁷⁵

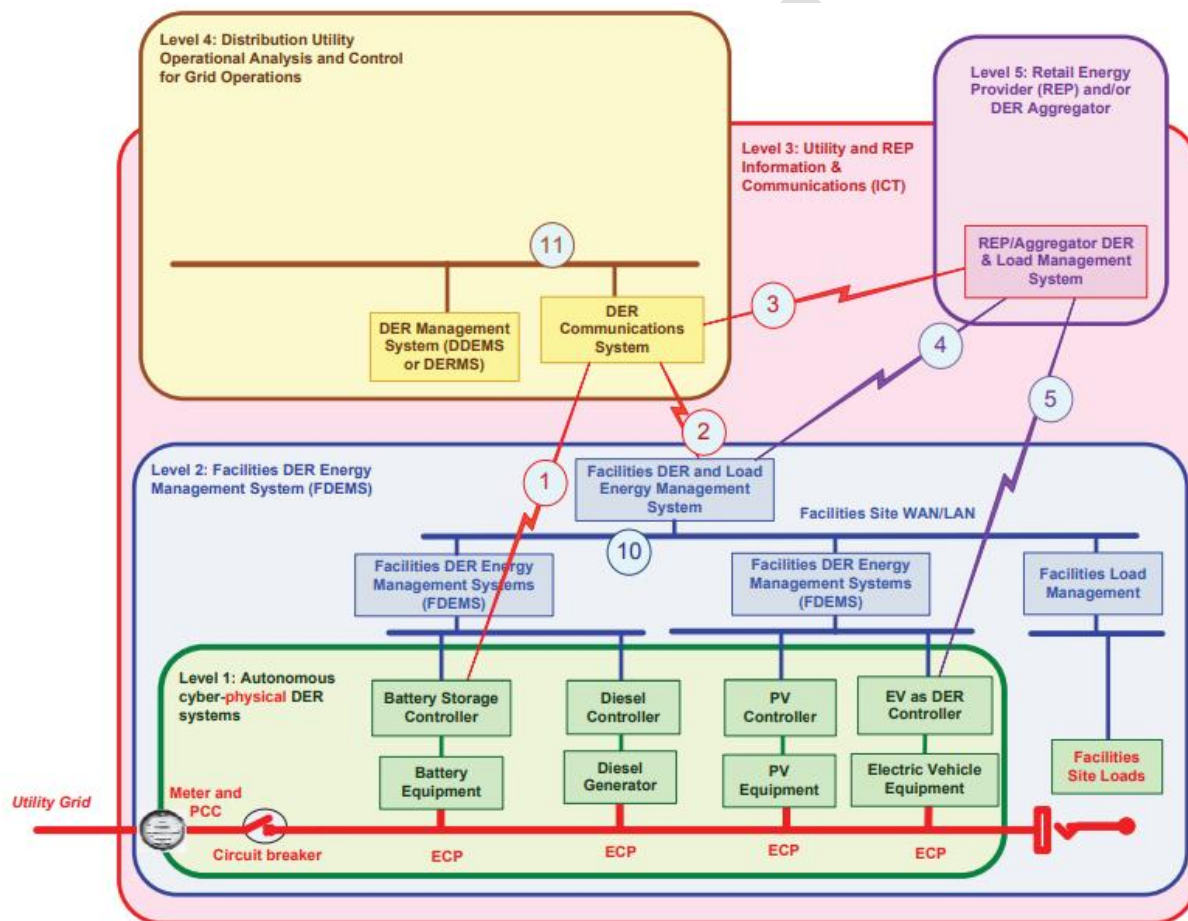


Figure 5 presents an overview of the status and expected coverage in California's Rule 21 for communication aspects of smart inverter systems.

⁷⁵

http://www.energy.ca.gov/electricity_analysis/rule21/documents/SIWG_Phase_2_Communications_Recommendations_for_CPUC.pdf

Figure 5: Status and expected coverage in Rule 21 for communication aspects⁷⁶

| Agreement that all Smart Inverter DER systems shall be <i>CAPABLE</i> of communications Decision on which DER systems shall implement communications to be made during interconnection process | | | |
|---|--|---|---|
| <u>Communications Layers</u> | <u>Possible Communication Choices</u> | <u>Status</u> | <u>What Should Be Covered in Rule 21?</u> |
| Utility DER-Related Applications and Databases | Cyber Security | ← Cyber security requirements. Utility privacy agreement | Security requirements: policies & technologies |
| | Profile of Data Exchanges | ← General agreement on monitoring and control data requirements. Grouping? | Data sets and performance required by utilities |
| Info Model | IEC 61850 Info Model | ← Agreement on IEC 61850 as Info Model | Use IEC 61850 info model |
| "Application" Protocol | Utility Protocol | ← Utility agreement on SEP 2 as default protocol, with SIWG SEP 2 profile | SEP2 Based on IEC 61850 Abstract Info Model |
| "Transport" Protocol | Internet Protocols: TCP/IP | ← Agreement on Internet Protocols | TCP/IP |
| Communications Media | | | |
| Gateway/Translator between protocols or Common Protocol | <ul style="list-style-type: none"> Utility private WAN Cellphone GPRS Public Internet AMI network Telecomm provider | ← Gateway/Translator to use utility-selected protocol ← No restrictions on media although media types can affect performance and security | Not included |
| Communications Media | | | |
| "Transport" Protocol | Internet Protocols: IP | ← Agreement on IP | Not included |
| "Application" Protocol | Facility or DER Protocol | ← For example, ModBus, GOOSE | Not included |
| Info Model | IEC 61850 Info Model | ← Agreement on IEC 61850 as Info Model | Not included |
| DER Controller of Smart Inverter | | ← Testing details to be worked out | Not included |

4. 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 DER. 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.

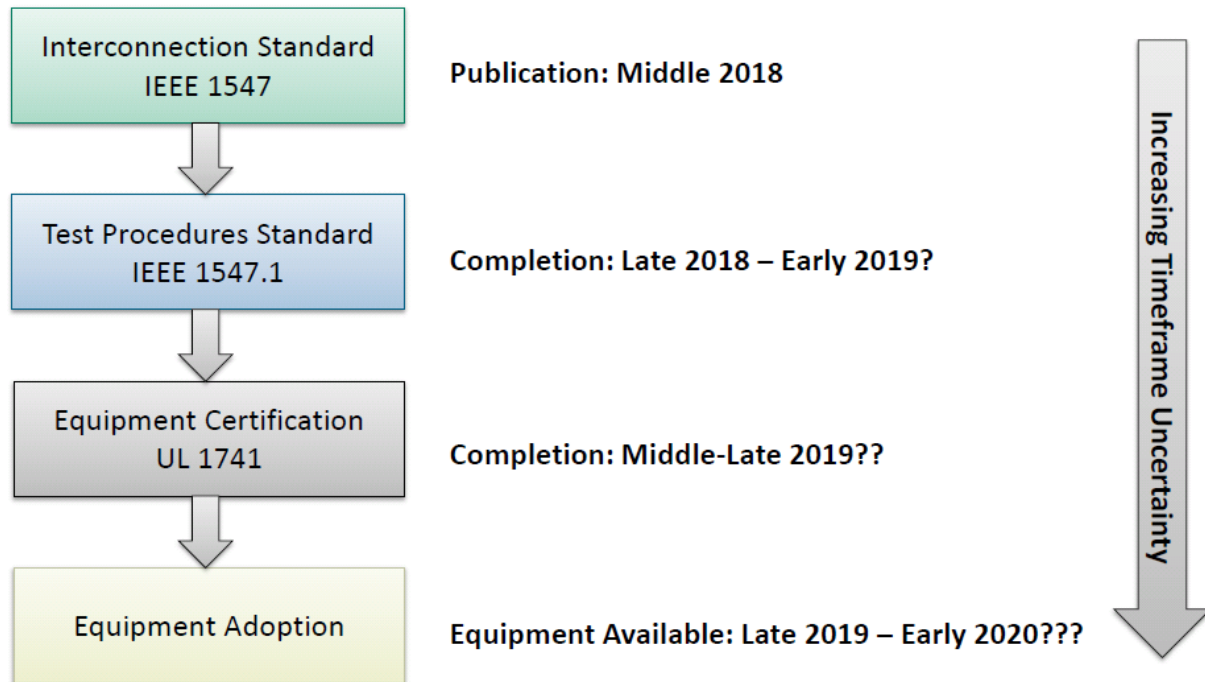
The implementation of the IEEE 1547-2018 standard update is an ongoing process and is not expected to be done until 2020. Figure 6 presents an overview of the IEEE 1547-2018 update process that includes updates to the test procedures standard (IEEE 1547.1) followed by equipment certification by Underwriter Laboratory (UL 1741) in 2019. The updated standard is expected to be adopted by equipment manufacturers by 2020. The successful roll-out of the new

⁷⁶

http://www.energy.ca.gov/electricity_analysis/rule21/documents/SIWG_Phase_2_Communications_Recommendations_for_CPUC.pdf

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 6: 1547-2018 Update Process



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, the data, and the analysis of modeling results for an IDP, which commissions should be aware of as they guide and oversee the IDP process.

A. Policy Drivers of DER Growth

Across the U.S., 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 to source a certain amount of energy from renewable sources. Utilities demonstrate RPS compliance by obtaining 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 DR⁷⁷ and energy storage.⁷⁸ Recently, several states have established energy storage targets and others are considering targets for DR.⁷⁹
- 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 non-local 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.

Incentives for DERs

- Federal Tax incentives including the Solar Investment Tax Credit (Solar ITC), 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.

⁷⁷ Pennsylvania Act 129 establishes demand reduction targets.

http://www.puc.state.pa.us/filing_resources/issues_laws_regulations/act_129_information.aspx

⁷⁸ New Jersey A3723 establishes a goal of 600 MW of energy storage by 2021 and 2,000 MW of energy storage by 2030. https://www.nj.gov/governor/news/news/562018/approved/20180523a_cleanEnergy.shtml

⁷⁹ New Jersey A3723

- Direct incentives for DERs, including 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.
- Specialized financial institutions, such as the DC Green Bank,⁸⁰ are public or quasi-public entities that use public capital and bonding authority to spark private capital investment in clean energy projects, including DERs.
- Multi-service 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” that 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 and reliable 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

⁸⁰ <https://doee.dc.gov/greenbank>

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, and advanced digital designs, etc., 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, 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 System (HEMS) |
| | Electric Load as Reliability Resource |
| | Advanced Metering Infrastructure (AMI) |
| Sensing and Measurement | Radio Frequency Identification (RFID) |
| Integrated Communications | Home Area Networks (HAN) |
| | Internet 2 (IP6) |
| | Fiber-to-Home (FTH) |
| | WiMax (4G) |
| | Cellular (3G) |
| | WiFi |
| | 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, and 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, 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 Management 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 |

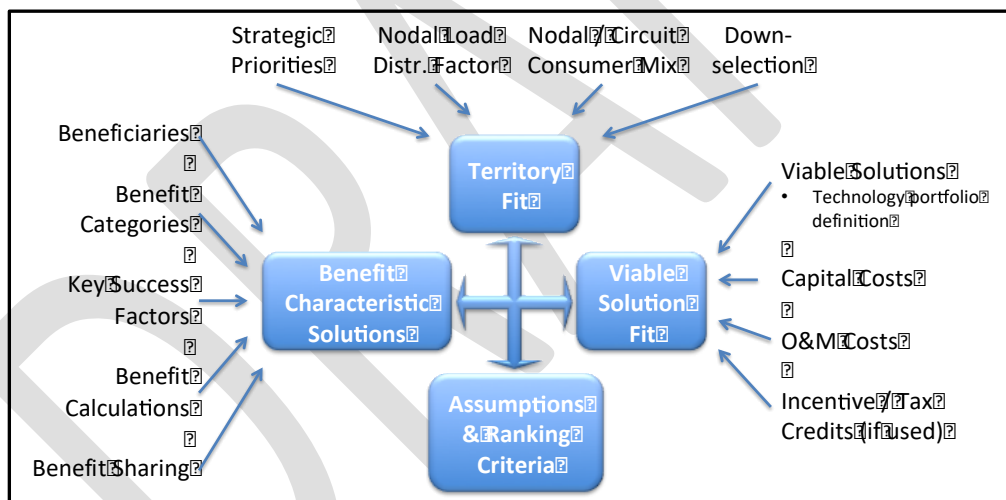
A Cost/Benefit Analysis (CBA) should be undertaken to identify leading technologies in a “Viable Solution Portfolio” that can improve the reliability of the grid, lower costs to consumers,

and yield system, consumer, and societal benefits. In the CBA, costs could be based on the full lifecycle 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 would provide the most benefits, as described by the beneficial characteristic solutions. Figure 7 below 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.

1. Why the Evolution Toward Transactive Energy is Important

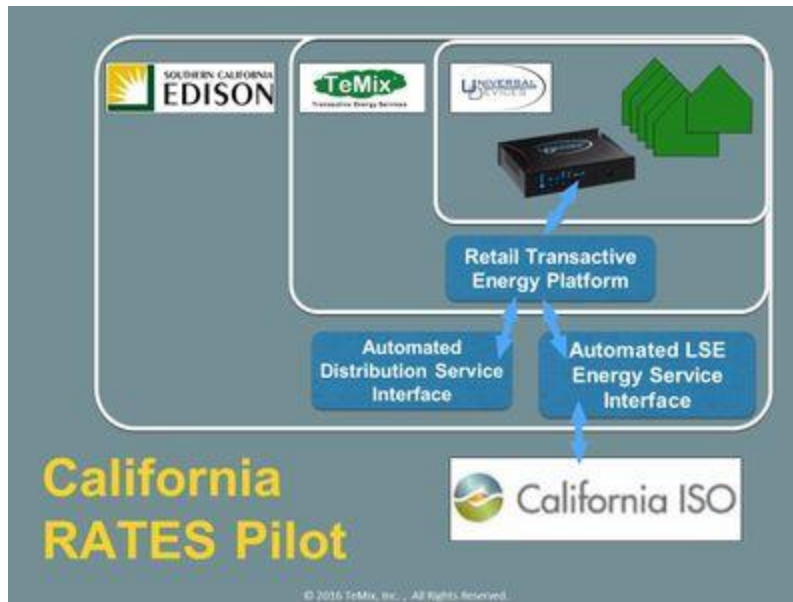
Resources at the distribution level are operated by devices that are optimized economically by a local intelligent controller that is administered by the user or an aggregator charged with representing the user's interest. The local controller receives transactive information and utilizes the user preferences 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's 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, a load serving entity, and customers who are producers and consumers of electricity.

Figure 8: California Retail Automated Transactive Energy System⁸¹



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 each other in a market environment. The complex structure of the grid including coupling among various entities means that transactive energy systems are designed for multiple objective optimization that spans multiple timescales 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 OCHP and OCPP, that enable standardized data sharing between distribution system operators and EV charging equipment operators.

Communications standards, protocols, and data models enable the transfer of “messages” between DERs, applications, aggregators, distribution system operators, and transmission system operators. The messaging requirements for transactive energy can be classified into the following:

- Resource management

⁸¹ <https://rates.energy/overview-1>

- 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
- 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.⁸² 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 judgement 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 their usage profile allows them to engage with utilities and other producers of energy to develop innovative customer solutions. Availability of usage data also empowers non-traditional 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.

A standardized approach to data access takes three basic forms:

⁸² <http://www.pointview.com/data/2017/06/1904/pdf/James-Mater-30645.pdf>

- 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 non-utility 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. Department of Energy, 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

To be drafted by Steering Committee/RAP following stakeholder review

DRAFT

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GLOSSARY OF TERMS

Action Plan: The component of a completed IDP that identifies specific activities to be taken to address near-term system needs.

Advanced Distribution Management System: 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: 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: 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 on the system and define strategies to resolve power system failures.

Hard vs. 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. Non-hardware 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.

Net Load: In the context of IDP, the gross customer demand for electricity minus any portion of that demand that will be served by behind-the-meter DERs.

Non-Wires Alternative: 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: 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: 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, based on the 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 A - 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 EDCs 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 EDCs 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 become 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 B – USING DERS TO MEET DISTRIBUTION SYSTEM NEEDS

In some cases, electric utilities can directly or indirectly⁸³ use DERs to reduce the electrical energy (MWh) or peak demand (MW) requirements of the customers they serve. The customers and/or third parties may be able to extract additional economic value from wholesale market revenues or through reductions in their utility bills.

The following three examples illustrate different ways DERs have been beneficially used by utilities and/or grid operators to meet distribution system needs.

Energy Efficiency Example

The approach of encouraging utility customers to use less electricity to moderate future electricity price increases was first adopted by Pennsylvania Power & Light (PPL) in the late summer of 1972. The utility CEO, Jack Busby, announced that the utility's economic studies showed that the average cost of generating a kWh of electricity (\$/kWh), which had been steadily falling during the time the utility had been in existence, had reached its lowest level in 1970, and from now on it would be rising.⁸⁴ In the past, more electricity sales meant both the utility and its customers benefited from rapidly increasing usage because the economies of scale meant lower costs and lower \$/kWh. The new analysis showed that high interest rates and new regulations meant that every time a new power plant and grid expansion were undertaken, rates would increase, and the best way to slow the rate of increases was to slow the annual rate of increase of electricity sales. Previously, PPL's marketing efforts had always been focused on promoting more usage, with the recent efforts targeting the adoption of electric heat pumps for space heating and cooling, replacing fuel-burning heaters and window-mounted air conditioners or fan-only cooling. Now, the marketing message would be for customers to practice energy conservation by adding insulation to their home, turning-off lights when leaving a room, and adjusting thermostat settings so less electricity or fuel is consumed. To provide more guidance, PPL built and gave tours of an Energy-Saving Demonstration Home that displayed several energy-efficient design features.

Subsequently, the federal government under President Nixon and Carter echoed the same "Use Less Energy" message, and laws were passed and regulations issued that encouraged end-use customers to install DERs. Electric utilities were asked to offer residential customers a walk-through energy audit and report containing EE recommendations. A few states began to require electric utilities –and in some cases also gas utilities – to offer EE programs to customers, and over time more and more states saw the benefits of such programs and adopted similar requirements or authorized a state agency or a third party to offer the program. In addition to providing information about energy-efficient practices, the programs typically also featured financial incentives to further encourage the installation of energy-efficient equipment. The federal government also collaborated with manufactures and builders to develop codes and

⁸³ "Direct use" means the utility owns, installs, and controls the DERs. "Indirect use" means the utility or the grid operator enters into contractual agreements to compensate DER owners (third parties and/or customers) or DER aggregators for operating their DERs in ways that meet distribution system needs.

⁸⁴ A member of the team of authors of this manual, William Steigelmann, was present at one of the first public presentations where Mr. Busby announced the new policy.

standards that specified efficiency values for homes, buildings, and new equipment manufactured or imported after a specific date. Beyond EE, other types of DERs encouraged by federal government actions included combined heat and power systems (CHP, also known as “cogeneration”), solar water heating, and self-generation of electricity by using renewable energy (solar, wind, hydro, geothermal, and biomass).

Demand Response Example

DR programs have been offered by utilities for decades. Historically, the primary reason utilities offered DR programs was to have a means to curtail load in a controlled fashion when there was a danger that the total load might exceed the total power supply capability (i.e., the aggregate power output of all the utility’s power plants plus firm power purchases from other utilities, minus power losses in the transmission and distribution grids). Since most utilities in the U.S. experience peak load conditions during a very hot summer afternoon when air conditioning equipment is fully loaded and most businesses are operating, load curtailments were typically focused on achieving small reductions in a large number of air conditioning units. This was done either by raising the thermostat set-point a few degrees or by cycling the compressors, turning them off for ten or fifteen minutes and then back on for the same length of time. Additional load reductions could be achieved by turning-off equipment such as electric water heaters and swimming pool pumps for a few hours. In larger buildings, some lights can be dimmed or turned off, the operation of some equipment can be interrupted, and the operating speed of fans and pumps can be reduced. Also, a back-up generator can be operated to power some equipment, or to operate in parallel with the utility grid, which accomplishes the fundamental goal of reducing the facility load supplied from the grid.

To obtain this power curtailment ability, the utility would undertake DR programs that incorporated one or both of the following initiatives:

- Hire a contractor to recruit residential and small-business customers to become program participants, which meant allowing the contractor to install the needed controls and the means for the contractor to remotely send curtailment start and stop signals to these controls when the utility requested a load reduction. The contractor would need to have a way of measuring or accurately estimating the specific MW of load reduction achieved for each event. The utility would pay the customer a fixed amount per summer month for agreeing to participate for up to a specified maximum number of curtailment events. In most programs the customer was permitted to override the control a few times without having a penalty (i.e., incentive reduction) imposed. These terms could vary based on the utility tariff or contract.
- Hire a contractor to recruit large non-residential (commercial, institutional, and industrial) customers to become program participants. Because the various facilities operated by these customers are highly diverse, the contractor typically would need to inspect many of the facilities to help the customer’s staff identify equipment that could be controlled (turned off, cycled off and on, slowed/dimmed, or back-up generator operated). Often the control actions needed to produce the load reductions could be accomplished via the facility’s energy management system. Some DR programs incorporated thermal storage via tanks that could hold chilled water or ice. The utility

incentive to the customer was proportional to the kW load reduction that could be demonstrated in a test.

After large-customer DR programs had operated for a number of years and the customers had gained a good deal of experience with them, customers were permitted to participate directly without the involvement of an overseeing contractor.

For the past several years regional grid operators have been conducting competitive auctions to select which power plants will supply capacity to the grid a few years in the future. The whole process is overseen by FERC. After the first couple of auctions, utilities and the contractors who ran the DR programs argued for the inclusion of DR programs, arguing that load reductions accomplished the same end-goal as generating plants: achieving a match between power supply and load. After extended discussions and protests from power plant owners, FERC eventually ruled that the regional grid operators should write rules that allow DR programs (which produce peak load reductions) and EE programs (which produce load reductions every day of the year) as well as individual customers that meet the minimum reduction threshold, all be permitted to participate as bidders. In the past few years an additional DER – electric storage batteries -- has been included in some bids. Although thermal storage, electrical storage (i.e., batteries), and EE have a relatively high cost per kW of load reduction, these DERs can be used on a daily basis to produce electric-bill savings for their customer, which can off-set much of the cost premium. Batteries can also be used to provide ancillary grid services on a routine basis, for which the regional grid operator will provide a payment.

Non-Wires Alternative Example

NWAs generally encompass DERs such as DG, DR, energy storage, and possibly EE. Neither distribution utilities nor FERC have consistently defined the term at either the distribution or transmission level. The objective of an NWA analysis is to allow the distribution utility to defer or avoid upgrades to the grid by procuring NWA solutions at a lower cost, while maintaining grid reliability.

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 above 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,⁸⁵ 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 pre-set 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

⁸⁵ For example, regulators in New York, Maine, Rhode Island, and California have ordered utilities to develop NWAs.

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.⁸⁶ 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 5.

Table 5: Sample NWA Project Suitability Criteria from Central Hudson⁸⁷

| Criteria | Potential Elements Addressed | |
|--------------------------|---|-----------------|
| Project Type Suitability | Project types include Load Relief and Reliability*. Other categories currently have minimal suitability and will be reviewed as suitability changes due to State policy or technological changes. | |
| Timeline Suitability | Large Project | 36 to 60 months |
| | Small Project | 18 to 24 months |
| Cost Suitability | Large Project | ≥ \$1M |
| | Small Project | ≥ \$300k |

⁸⁶ Joint Utilities Filing of Utility-Specific Implementation Matrices for Non-Wires Alternatives Suitability Criteria. March 2017. Case # 16-M-0411 and 14-M-0101

⁸⁷ <https://www.cenhud.com/workingwithus/non-wires-alternative-opportunities>