AEE INSTITUTE

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July 20, 2017

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, MN 55101

Re: Comments of the Advanced Energy Economy Institute on Distribution System Planning, Docket No. E999/CI-15-556

Dear Mr. Wolf,

The Advanced Energy Economy Institute (AEE Institute) respectfully submits these comments in response to the Commission's Notice of Comment Period on April 21, 2017. Our comments provide perspectives on Section C, and "relate to the efficient and economic investment in technological advancements, infrastructure and integration of DER into distribution system planning and operations." (page 7)

If there are any questions, comments, or concerns related to these comments, feel free to contact me directly.

Regards,

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State of Minnesota
Before the
Minnesota Public Utilities Commission

In the Matter of the Commission Investigation into Grid Modernization: Focus on Distribution System Planning	Docket no. E999/CI-15-556 COMMENTS

Introduction

The Advanced Energy Economy Institute (AEE Institute) appreciates the opportunity to provide these comments in response to the Minnesota Public Utilities Commission's (hereafter PUC or Commission) Notice of Comment Period on Distribution System Planning Efforts and Considerations, issued April 21, 2017.

AEE Institute is a 501(c)(3) charitable organization whose mission is to raise awareness of the public benefits and opportunities of advanced energy. AEE Institute provides critical data to drive the policy discussion on key issues through commissioned research and reports, data aggregation and analytic tools. AEE Institute also provides a forum where leaders can address energy challenges and opportunities facing the United States. AEE Institute is affiliated with Advanced Energy Economy (AEE), a 501(c)(6) national business association, representing leaders in the advanced energy industry. AEE supports a broad portfolio of technologies, products and services that enhances U.S. competitiveness and economic growth through an efficient, high-performing energy system that is clean, secure and affordable.

AEE Institute has substantial experience in participating in regulatory reform, grid modernization and "utility-of-the-future" discussions and proceedings across the country. AEE Institute has been very active in the New York Reforming the Energy Vision proceeding for the past three years, and has participated in similar efforts in California, Ohio, Illinois, Michigan, Pennsylvania, Rhode Island, the District of Columbia, and Maryland.

Distribution system planning will need to change to address, accommodate and benefit from changing technologies on both the grid- and customer-side of the meter, including increasing customer adoption of distributed energy resources (DER).[1] Fortunately, Minnesota has begun to anticipate these changes and has established several planning and regulatory mechanisms, including the discussions from the series of Grid Modernization workshops that were held in 2015-2016. We commend Minnesota for its vision and leadership, and we greatly appreciate the opportunity to engage in this proceeding.

[1] We define DER broadly to include energy efficiency, demand response, distributed generation of all types, energy storage, electric vehicles and microgrids.

1)Evaluation of utility plans. Discuss:

a. How utility distribution plans should be used in other proceedings: Should distribution plans be approved by the Commission? If so, what are the implications for cost recovery, i.e., to what extent would Commission approval of a plan constitute a finding of prudence?

We recommend that the Commission approve the distribution system plans and utilize the outputs from the plans to inform other Commission processes, but we suggest that the plan approvals should not constitute a formal finding of prudency. Our rationale for this recommendation is that if approval of the plans were to constitute a finding of prudency, that finding could have the unintended consequence of making the distribution system planning process overly formal and contentious, with parties needing to invest significant resources of time and money to engage; a preferable option is a less formal, non-adjudicatory, and more open and collaborative process where a wide range of stakeholders are engaged to help inform the process and develop solutions. Nevertheless, we support the Commission approving the distribution system plans before they are used, which would give stakeholders an opportunity to weigh in on the adequacy of the plans and give the Commission the opportunity to confirm whether the utilities are adhering to the guidelines and expectations of the Commission with respect to the plan itself and the process.

b. How specifically should an approved distribution system plan be integrated with other planning activities: resource planning, interconnection, transmission, or others?

Distribution system planning should be closely integrated with other planning activities including resource planning, interconnection, transmission and DER deployment.[2] The growth of DER may alleviate the need for new centralized generation and/or

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[2] We support an integrated system planning approach, along the lines of the report on integrated distribution system planning prepared for the Commission in August 2016, by ICF International. ICF International. *Integrated Distribution Planning: Prepared for the Minnesota Public Utilities Commission.* U.S. Department of Energy. Washington, DC, 2016. Accessed June 15, 2017. URL: https://energy.gov/sites/prod/files/2016/09/f33/DOE%20MPUC%20Integrated%20Distribution%20Planning%208312016.pdf

transmission, and DER may also provide the opportunity for non-wires alternatives (NWA) projects that can substitute in certain circumstances for traditional utility distribution system solutions. Rising DER deployment also has implications for the types of distribution system investments that will be needed to accommodate and integrate those resources. Planning processes at all levels should take various DER growth forecasts and options into account and drive towards decisions that are optimal for the system and for customers. The growth of DER will also have implications for interconnection, with needs for improvements in interconnection processes to keep pace with market growth, and with a growing importance for hosting capacity analyses to help identify the best places to locate DER on the system. For example, growth of electric vehicles sales may provide opportunities and raise challenges for distribution system operators, and considering various market growth scenarios would be highly valuable.

In developing distribution system plans, the Commission, the utilities and other stakeholders should think through the different ways in which the plans may be used so that they have the right outputs and level of detail to be helpful for other planning processes. For example, if the goal is to identify NWA opportunities, then the plans should contain sufficient information about distribution system loads, load forecasts and conditions, such that DER providers can propose solutions that will meet system needs. The integration of distribution system information could enable a more location-specific accounting for the value of demand-side resources and therefore influence planning for energy efficiency, demand response, and other conservation improvement options. This information could include, for example, hourly load data, with projections, as well as DER hosting capacity on different circuits. A price range of avoided utility upgrades is useful to help DER providers identify opportunities where their technologies are cost-effective.

We also recognize that distribution system planning and its integration with other planning processes may best be done in an evolutionary approach. Implementation of distribution system planning process changes can align with the pace of industry and system changes, such as rates of DER adoption and evolving customer needs. For example, MoreThanSmart advocates for a "Walk-Jog-Run" Model[3] to characterize investment stages and states of DER penetration to guide transition of distribution system plans. "Walking" primarily involves anticipating changes. "Jogging" involves more advanced analyses, usually due to increased DER penetration. "Running" may involve more complex analyses based on a high-penetration of DERs and sophisticated data collection and analysis, which can inform system wide decisions. In an illustrative case, "Walking" may mean initiating DER hosting capacity analysis and improving interconnection processes, "Jogging" may entail characterizing locational benefits of DERs, and "Running" may involve using distribution system planning outputs to inform integrated resource plans and/or transmission planning.

c. **What are reasonable options for stakeholder participation in the planning process: direct engagement in the development of plans, the review of draft and final plans, other?**

Direct stakeholder engagement in the development of the plans, as well as stakeholder review of the draft and final plans is the optimal means of facilitating an improved, ore transparent distribution planning process. To ensure that plans are meaningful and developed with both utility and other stakeholder input we recommend that the Commission directly facilitate the process or that the Commission directly hire a third-party facilitator.

DER providers are in the best position to inform the distribution system plans about DER costs and capabilities. The goal of involving non-utility stakeholders is not just to have them review and comment on the plans, but to be more actively involved in identifying potential DER solutions to system needs that can then be incorporated into the plan and subsequently into rate cases and approved investment plans. They can also inform the Commission and utilities on the types of customer and system data they would need to develop those solutions.

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[3] De Martini, P., Brunello, T., and Howley, A. Planning for More Distributed Energy Resources on the Grid: A Summary for Policymakers on the Walk-Jog-Run Model. MoreThanSmart. Oakland, CA. 2016.

d. **Criteria or metrics the Commission should use in evaluating proposed distribution plans. How often should a utility distribution plan be submitted for Commission review?**

To evaluate the proposed distribution system plans, the Commission should develop a comprehensive benefit cost analysis (BCA) framework, and one that can compare traditional utility solutions to DER solutions. Using such a framework allows utilities to compare traditional solutions with alternative and emerging technologies, and can also inform utilities on the types of distribution system investments that will lead to greater benefits from investments in DER. Such a framework may include a wide range of technologies and appropriate societal benefits. For example, in the MN Department of Commerce's Value of Solar methodology, a social cost of carbon is embedded in calculations.[4]

We recognize that a wide range of societal benefits are delivered through utility infrastructure. By establishing an appropriate valuation framework, the Commission can guide distribution system planning efforts toward uniform and understandable evaluative principles. Other states have recognized that use of the Societal Cost Test provides the most complete picture of the total benefits of an investment. For example, to manage the impact of looking at full societal benefits, many of which are not currently reflected in retail rates, New York set the Societal Cost Test as the primary test for all utility investments, but retained the option to use the Ratepayer Impact Measure test as a backstop keep track of rate impacts.[5]

In terms of frequency of plan review, we recommend that the Commission review the plans yearly given the rapid pace of change in the industry today. This recommendation would be consistent with Michigan's approach of requiring a yearly refresh of utility 5-year distribution system plans, starting this year. [6]

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[4] Minnesota Department of Commerce, Division of Energy Resources. *Minnesota Value of Solar: Methodology*. 2014 http://mn.gov/commerce-stat/pdfs/vos-methodology.pdf

[5] Case 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. Order Establishing the Benefit Cost Analysis Framework, Issued and Effective: January 21, 2016.

[6] DTE Energy Case U-18014 draft plan due by July 1, 2017; final plan due December 31, 2017. Consumers Energy Case U-179900 draft plan due by August 1, 2017; final plan due January 31, 2018

2) Feasibility of planning enhancements. Discuss:

a. Whether all investor-owned utilities should adopt uniform planning processes?

We support the development and use of uniform planning processes, while also understanding that utilities have differing systems and capabilities for planning. Specifically, we think about uniform planning processes in two categories: 1) the stakeholder engagement processes, and 2) tools and methodologies.

First, stakeholder engagement processes should be open and transparent, and uniform across utilities. System and customer data, modeling assumptions, and modeling scenarios should be shared such that stakeholders may provide valuable feedback for solutions to problems and utilities can identify opportunities to use DER to solve system needs more affordably and effectively.

Second, the tools and methodologies used for planning by all utilities should include, but are not limited to:

- Probabilistic forecasting of multiple DER and load growth scenarios
- Hosting capacity analyses
- Locational value of DER
- Interconnection studies
- Creation of a uniform benefit cost analysis framework

We recognize that each utility may be at a different stage of development with respect to using various tools, as well as the ability to collect and develop different levels of granular data. They may also have varying levels of automation on their system that dictate the type of planning tools that are most useful. Nevertheless, the goal should be to move all the utilities to a similar level of detail and uniformity of tools. This standardization will improve outcomes by making it more efficient for DER providers to participate in individual planning processes and to offer appropriate solutions.

b. **Taking resource concerns into account, what are the events or system conditions that should trigger the adoption of enhanced planning processes by an individual utility? (e.g., high distributed generation interconnection requests, high DER penetration, high capital/operating budget needs, other)**

Utilities should begin moving towards enhanced planning processes now. Getting distribution system planning processes right will take time and practice for utilities, regulators, and stakeholders, and building expertise in advance of events or systems conditions will be important. All utilities should advance the capabilities of their hosting capacity tools as quickly as is practicable.[7]

Regardless of the level of DER deployment or the level of investment needed, the technologies available today can improve system operations, improve the customer experience, and cost-effectively improve essential services for Minnesota's citizens and businesses. Minnesota can be proactive, rather than reactive, via enhanced planning processes. As mentioned above, a Walk-Jog-Run approach may be an appropriate way with which to view the evolution of distribution system planning in Minnesota.

The Commission should continue to dedicate resources to develop internal capacity to evaluate plans. The development of regulatory staff expertise in this area is crucial as distribution system planning and similar processes evolve and become more complex.

3) Forecasting. Discuss whether demand forecasting and DER modeling may be improved by:

a. **Integrating system-wide forecasts, circuit-level forecasts, and forecasts of geographic dispersion of DER to map potential impacts, both beneficial and detrimental, of increased DER, or other**

b. **Using probabilistic analysis for availability of DER in high-DER-penetration scenarios, i.e. considering the likelihood of coincident failure or unavailability of multiple DER assets**

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[7] We also recommend that distribution system plans inform an assessment of how investments are impacting hosting capacity over the long term. These assessments will be essential to driving policy analysis in related proceedings.

We believe that both multiple scenarios and probabilistic planning will best inform forecasting going forward. As DER adoption increases, predicting the types, amount, and adoption rates of DERs will change. This will make singular and deterministic forecasting practices less viable and less valuable as a means of predicting distribution system needs over the long-term.

We recommend developing assumptions about different scenario options, making all resources available for inclusion in the scenarios, as opposed to developing technology-specific scenarios. This approach is consistent with our view of resource options. Moreover, DERs represent a resource available for forecast modeling, and their deployment should not be modeled as a load modification. In many cases, DERs can be a least cost resource.

In response to 3b, "considering the likelihood of coincident failure or unavailability of multiple DER assets," DER deployment is not necessarily a risk, but rather may provide opportunities. Widely deployed DER, particularly DER of varying types, is likely to have low likelihood of coincident failure. Rather, multiple DER assets may have a better chance of performing well than a single large asset that could experience fault and pose widespread system risk. Further, distributed, coordinated and/or aggregated DERs can provide significant risk-management benefits. As an example of coordinated action, demand response provides firm capacity reserves and system-wide peak shaving when demand is high. During the 2014 Polar Vortex, grid operators in PJM and ERCOT called on demand response, respectively, to help prevent blackouts when traditional generation sources were unable to respond. In PJM, DR was estimated at over 2,000 MW during crucial operating hours.[8] In Texas, ERCOT noted that DR provided nearly 496 MW of capacity, nearly 127% of contracted DR.[9]

We also recommend that probabilistic analysis not just be limited to DER, but used more broadly, for example, in defining future load growth scenarios.

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[8] RTO Insider. "Polar Vortex Revisited: How DR Helped Keep the Lights On.' January 21, 2014. URL: https://www.rtoinsider.com/pjm-demand-response-14c/

[9] Savenije, Davide. "AEMA: Demand response saved Texas during polar vortex" Utility Dive. April 19, 2014. http://www.utilitydive.com/news/aema-demand-response-saved-texas-during-polar-vortex/249212/

4) Scenarios. Discuss:

a. What type of input should stakeholders have into the selection of planning scenarios?

Stakeholder input is essential in building planning scenarios. The Commission should rely on broad stakeholder input for building scenario and forecast assumptions. Utilities may not have full, up-to-date information about DER cost and performance, as well as planned DER deployment at the distribution level. Stakeholder input can also help with development of the macroeconomic and other broad assumptions that help define different scenarios.

b. What criteria should be used by utilities to identify relevant planning scenarios?

To identify relevant planning scenarios, utilities should ensure that scenarios are aligned with the state's public policy goals. In the Minnesota PUC Staff report on grid modernization, the following goals were articulated (pg. 14):[10]

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;
- Enable greater customer engagement, empowerment, and options for energy services;
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies;
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs;
- Facilitate comprehensive, coordinated, transparent, integrated distribution system planning.

[10] Minnesota Public Utilities Commission. *Staff Report on Grid Modernization*. St. Paul, MN, March 2016.

Distribution system planning is both an articulated goal in and of itself, and a critical means of delivering on the other goals. Benefits due to those state policies may also inform scenario planning. For example, if public health benefits accrue due to increased DER deployment, those benefits may be appropriate for consideration.

c. **Should all utilities use common planning scenarios, or should they be tailored to the circumstances of individual utilities?**

Consistent with the distribution system plans, the basic principles, assumptions and data should be common for utility planning scenarios. However, scenarios should be adjusted based on utility-specific circumstances. For example, utilities may have differing obligations under renewable portfolio standards and should model scenarios fit for their specific compliance obligations.

In addition, the data needs, assumptions, and policy drivers of scenarios may change. The Commission should engage with stakeholders to periodically update the common elements of planning scenarios.

d. **Should planning scenarios be common across multiple planning cycles, or should planning scenarios be redefined with each new planning cycle?**

Although there is value in continuity from one planning cycle to the next, given the rapid pace of change, planning scenarios should be refreshed with each new planning cycle to ensure that they incorporate the latest developments. Nevertheless, the same types of scenarios can be carried forward year-to-year, for example, a "high economic growth" scenario. New scenarios can be introduced, or existing ones retired, as conditions warrant.

e. **What are reasonable timeframes for each use and consideration of a scenario, and how often should they be reevaluated?**

We recommend five-to-ten year forecasts, refreshing once a year. We encourage a manageable planning timeline, appropriate to forecast under uncertainty, with a frequent update.

5) Standards. Discuss:

a. Standards and codes that will be applicable to the enhanced integration of DER into distribution system planning and operations

Standards are a critical part of integrating DER into distribution systems. Related to distribution system planning, at least two categories of standards are important: 1) interconnection standards, and 2) interoperability standards.

First, interconnection standards are important to distribution system planning. A standardized interconnection process helps to speed the process of new generator connections, reduces interconnection costs, ensures grid reliability, and avoids undue discrimination.[11] Interconnection standards may also interact across and between state and federal jurisdictions. Thus, development of interconnection standards and interconnection processes should include input from Federal Energy Regulatory Commission standards[12] and Midcontinent ISO standards,[13] where applicable.

For technical interconnection standards, much of the industry has mature guidance. For example, the Institute of Electrical and Electronics Engineers (IEEE) series of 1547 standards address interconnection of DER with the grid. IEEE 1547 provides mandatory functional technical requirements, and presents choices about equipment and operating details for compliance with the standard. Minnesota should defer to this standard, and the Commission should ensure distribution system plans comply, as applicable.[14] The Commission should also include revisions to these standards that relate to smart inverters, as inverter technologies are likely to have growing importance

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[11] Rauch, Jason N. *Renewable Generator Interconnection.* U.S. Agency for International Development/National Association of Regulatory Utility Commissioners. March 24, 2014. Accessed June 19, 2017. URL: http://pubs.naruc.org/pub/5381D31C-2354-D714-51ED-08FD965CF29D

[12] For example, FERC Orders 2003, 2006, 661; Standard Interconnection Agreements and Procedures for Small Generators https://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp

[13] MISO Generator Interconnection information https://www.misoenergy.org/Planning/GeneratorInterconnection/Pages/GeneratorInterconnection.aspx

[14] For more information, see Basso, Thomas S. *IEEE 1547 and 2030 standards for distributed energy resources interconnection and interoperability with the electricity grid*. Vol. 15013. National Renewable Energy Laboratory, 2014. URL: http://www.nrel.gov/docs/fy15osti/63157.pdf

in the future, and the Commission could consider requiring all inverters used in the state to have smart inverter capabilities, even if these capabilities are only enabled later.

Second, interoperability standards are increasingly important. Beyond the physical systems, a modernized grid relies increasingly on two-way communications technologies to inform system operations and improvement opportunities. The communications and operational characteristics of technologies must work together. Interoperability can be defined as "the capability of two or more networks, systems, devices, applications, or components to share and readily use information securely and effectively with little or no inconvenience to the user."[15] Under the Energy Independence and Security Act of 2007, the National Institute of Standards and Technology (NIST) facilitated the development of significant interoperability standards.[16]

Interoperability crosses jurisdictional, operational, and supply/demand boundaries: It is important that operators of generation, transmission, distribution, and customers all connect in a way that ensures a safe, secure, and reliable grid.

6) Access to grid and planning data by customers and third parties. Discuss:

a. To what level should distribution planning data of Minnesota utilities be accessible to third parties

A core element of modern distribution system planning processes should be providing improved information to customers, regulators, and third parties to create a common discussion and enable non-utility stakeholders to propose solutions to grid needs. Improved information means greater transparency of system needs, operational concerns, and paths that will encourage innovation and prudent investment by utilities. In other words, the planning process should provide significant data for stakeholders, regulators, and customers to move toward the Commission's principles of a modern

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[15]U.S. Department of Energy. *Smartgrid.gov - What is the Smart Grid: Standards and Interoperability.* Accessed June 19, 2017.
URL:https://www.smartgrid.gov/recovery_act/overview/standards_interoperability.html

[16] Ibid, https://www.smartgrid.gov/recovery_act/overview/standards_interoperability.html

grid. We generally view this as being more than utilities providing data as part of specific solicitations for NWAs. Beyond this application, third parties should have access to information that enables them to develop new products and services that can be of benefit to specific customers and to the system.

Utilities, customers and third-parties will be users of system and customer data. To be useful, the data may need to be provided to each of these entities in a different format. Customers may need data in a summary form for it to be useful to them in making decisions about how to manage their energy use, including whether to adopt DER. Increasingly, customers will also need access to more granular data in a timely manner, for example, so that they can act in advance to reduce peak load before they impose costs on the system and incur higher charges as a result. Customers may also choose to delegate their energy management to third parties, who will then be the entities that need access to timely, granular data in a form that they can use. Similarly, providing third parties with timely access to system data can facilitate the planning process as well as execution of utility investment plans that are increasingly expected to rely on NWAs. Third-parties would also need access to system data to appropriately identify where DER can best meet system needs.

Data is critical for stakeholder engagement. Nevertheless, data should be shared in a way that ensures that customer trade secrets or individuals' personal identifiable information are not at risk. Further, data sharing should clearly relate to objectives and/or Commission principles. All data sharing should appropriately consider data characteristics, risks, and vulnerabilities.

In respect to privacy, there are many resources available to the Commission and many jurisdictions with existing privacy practices that may inform appropriate data sharing guidelines. The NIST Interagency Report 7628[17] provides an analytical framework for utilities and regulators to consider, including recommendations for security requirements and concerns, data privacy, and systems cybersecurity. Data sharing may be limited surrounding critical infrastructure assets, and any requests by distribution

[17] Smart Grid Interoperability Panel Cyber Security Working Group. "NISTIR 7628-Guidelines for Smart Grid Cyber Security vol. 1-3." Washington, DC: National Institute of Standards and Technology. Rev. 1 (2014). Accessed June 16, 2017. URL: http://nvlpubs.nist.gov/nistpubs/ir/2014/NIST.IR.7628r1.pdf

systems owners to withhold sensitive information should be justified to the Commission.

c. Discuss categories of data needed by third parties to:

i. Participate in developing system plans

ii. Critically review proposed plans

iii. Prepare commercial projects in response to plans

We believe the following data is important for third parties:

Distribution system characteristics

- Existing distribution characteristics at substation and feeder-level — coincident & non-coincident peaks, capacity levels, outage data projected investment needs
- Generation production characteristics, including those associated with variable resources
- Existing combined heat and power installations
- Hosting capacity at substation and feeder level

Distribution planning data

- Customer DG adoption forecasts
- Other customer DER adoption forecasts
- Distribution planning load forecasts, based on forecasting scenarios proposed elsewhere in the plan. [18]

d. Discuss the availability and importance of a standard, downloadable format for customers and third parties to assess planning opportunities

We support the use of standard, downloadable formats for data, including, but not limited to, the use of Green Button for customer data. Data sharing protocols should be non-proprietary and easily actionable by stakeholders.

[18] These recommendations are consistent with California Public Utilities Commission guidance on distribution system planning: California Public Utilities Commission. Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769. Draft Guidance for use in Utility AB 326 Section 769 Distribution System Plans. P 20 URL: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5107

Further, distribution system planning data should be appropriately structured with a data dictionary that includes standard definitions of data elements, their meanings, and the nature of values.

7) Hosting Capacity. Discuss:

a. What information should be made available to developers and the public, such as voltage, current generation, queued generation, peak and minimum load, and limiting factor criteria violations?

First, location-specific information should be available. As an example, both California and New York are employing "heat maps" of specific locations, with indicators of interconnection costs and queues, which are updated regularly.

Other important information may include circuit-specific conditions, customer breakdown, generation queues, interconnection agreement queues, and specific hosting capacity values.

b. Provide a description, method, and technological and personnel resources necessary, including security or password requirements, for conducting hosting capacity and making the data/output of the analysis available to the public

c. How should and in what format should the results of a hosting capacity analysis be made available?

Mapping and data should be refreshed regularly and publically available. In similar proceedings related to distribution system planning, the California Public Utilities Commission guidance suggests that utilities refresh publically available hosting capacity heat maps monthly. New York utilities publish feeder-level hosting capacity maps at least once per year.

We also believe that future hosting capacity information may require enhancements. As utilities and system operators engage in DER integration, we imagine that hosting capacity analyses will become more granular and dynamic. It will be important to continually develop and refine hosting capacity analysis use cases and methods. For example, New York expects utilities to provide advanced sub-feeder-level hosting capacity information by late 2017, and complete feeder-level hosting capacity analysis on all circuits by mid 2018.

8) Strawman distribution planning outlines and/or processes are welcome.

The stakeholder engagement process should be transparent. Administratively, it is important to organize planning processes to ensure the most stakeholder input possible. Technology providers, developers, and other critical stakeholders vary in their regularity of interacting with regulatory commissions and their processes. As an example of best practices, the Michigan Public Service Commission currently uses listservs and working groups to actively manage multiple subject matter working groups to address streams of energy law responsibilities.[19] We recommend that the complex planning processes be treated similarly, with parallel and distinct working groups and voluntary listservs. This process allows stakeholders to find specific tasks or subjects and will facilitate better engagement. The process could begin first with working groups that focus on developing guidance for utilities to follow when developing their plans. This process coalesces the stakeholder community around a shared vision, or at least a commonly agreeable vision, of what the distribution system plans should look like. Development of the plans and implementation can proceed more smoothly once this foundation has been laid.

9) Are there other issues or topics not covered here that are relevant to discuss in distribution system planning? If so, what are they and why are they relevant?

The decision to explore enhancements to the distribution system planning process is timely and opportune, as technological advancements and policy urgency are pushing commissions around the country. We view distribution system planning as a very important mechanism for attaining the grid of the future. With more granular data,

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[19] Michigan Public Service Commission Energy Implementation - URL: http://www.michigan.gov/mpsc/0,4639,7-159-16400_79103---,00.html

deeper and more instantaneous grid-visibility, and more involved customers and third-parties, planning for the distribution system must change.

To take full advantage of the benefits that new technologies can provide to the system, the utility business model may need to be realigned to put new technologies and traditional technologies on an equal playing field. New utility business models that should be explored include allowing a return on certain operational expenses and introducing performance based regulation (PBR). Planning processes would then evolve in parallel in response to utilities adjusting the way they do business in response to these changes to the regulatory framework.

<u>Return on Certain Operational Expenses</u>

The traditional cost-of-service utility business model based on earning a regulated rate of return on capital investments is not a natural fit with distribution planning that attempts to maximize the benefits of DER deployments and give customers more options for managing energy use and costs with DER. As customers deploy more DER, the opportunity for utilities to invest in traditional distribution assets may decrease, so long as the DERs are integrated well. However, other, different types of investments will be necessary, and new utility services will emerge. With an expectation of a high-DER future, it is beneficial to provide the utility with the motivation to plan for and operate the distribution system in a way that leverages private assets to minimize costs, and this process requires changes to the way the utility makes money. Under the current cost-of-service model, if the utility leverages an asset owned by a customer or a third party to support the grid rather than invest in its own solution, the utility will shrink its capital expenditures, its main source of profit. The utility will thus need other means of generating profits.

For example, if the utility contracts with an energy storage project owner or a distributed generator to provide capacity at a peak hour and avoids the need for a new transformer, the utility could earn on that service expense just as it would have earned on installing the new transformer. The fact that the asset is owned by a third party and the utility paid for a service expense rather than a capital investment does not change the outcome, and, in fact, the service-based arrangement may be a more cost-effective solution overall, to the benefit of all customers. Importantly, the utility is still fulfilling its core function of maintaining the reliability of the grid, although through different means. As such, the utility's profits should not suffer because of it. Allowing the utility to earn on these types of operating expenses that cost effectively replace a capital expenditure can help resolve this bias toward capital expenditures that is built into the current regulatory model.

Performance Based Regulation (PBR)

PBR is a regulatory framework that attempts to align the behavior and financial interests of regulated utilities with public interest objectives and consumer benefits. It does so by rewarding utilities for achieving well-defined performance metrics (outputs), as opposed to providing incentives related primarily to capital investment (inputs). Rewarding performance does not necessarily mean abandoning traditional cost of service approaches. PBR represents an evolution, not a revolution, in regulatory processes and revenue opportunities for utilities, wherein a state may choose to use a hybrid of cost-of-service and PBR approaches. The Commission should consider how a performance-based regulatory framework could help utilities transition toward desired system outcomes. In Minnesota, PBR has been supported by, and has been investigated through, both e21[20] and the Citizens League. [21]

Conclusion

AEE Institute appreciates the opportunity to submit these comments. We look forward to further opportunities to contribute to the Commission's important work related to grid modernization.

[20] e21 Initiative Phase II Report On implementing a framework for a 21st century electric system in Minnesota

[21]Citizens League. Policy Framework to Optimize Efficiency of the Electrical Energy System. Minneapolis, MN June 2014 URL:https://citizensleague.org/wp-content/uploads/2013/05/510.RPT_.Policy-Framework-to-Optimize-Efficiency-of-the-Electrical-Energy-System.pdf