**UM 2005 Distribution System Planning**

**New Opportunities Stage Webinar Series Archive**

This document serves as an archive of content from the webinar series noted above. The document will record webinar presentation abstracts, speaker bios, presentation slides, links to webinar recordings, and stakeholder questions. Staff will update the document regularly.

## Contents

## Webinar #1 – Integrated Distribution Planning Overview

**Presented by Paul De Martini, Newport Consulting**

**Thursday, April 30, 2020 from 2 - 3:30 p.m. Pacific**

**Presentation abstract**

An overview of Integrated Distribution Planning, this session will set the stage for many of the key issues to be considered during subsequent webinars in the coming weeks.

**Speaker bio**

Paul De Martini is a leading expert on the business, policy and technology dimensions of a more distributed power system. His work draws upon a unique set of successful executive experiences in transforming utility operations, building successful competitive energy services firms and growing technology ventures. His extensive writings and consulting work have influenced industry transformation efforts in Australia, Canada, and across the US.

**Presentation slides** can be viewed at the following links:

Presentation – Nick Sayen – https://www.oregon.gov/puc/utilities/Documents/DSP-Webinar1-PUC-Presentation.pdf

Presentation – Paul Martini – https://www.oregon.gov/puc/utilities/Documents/DSP-Webinar1-Presentation.pdf

**Webinar video**

A recording of the session can be viewed at the following link:
https://oregonpuc.granicus.com/MediaPlayer.php?view_id=2&clip_id=497

**Stakeholder questions**

*Please note that questions and answers may have been edited for clarity and brevity.*

1. How do assessments of community needs for resilience get factored into the planning process? How are communities engaged in the process?

   We're still early on community engagement for resilience. Communities have been leading efforts, with some reaching out to utilities as well.

   In Hawaii, a number of concurrent resilience planning activities considered both non-electric and electric issues. Hawaiian Electric led community outreach and outreach to the City and County of Honolulu to talk about critical facilities and resilience needs. In the Northeast, there are also examples of community outreach following Sandy. In California, community engagement on resilience is beginning given public safety power shutoffs. Since loss of electricity touches so many dimensions of our lives, it is important to understand community impacts.

In the threat assessment, start from the planning criteria that feed into analysis. On solution development, the range of solutions may include solutions beyond the utility (e.g., microgrids, storage, customer solutions). In Florida and Texas, commercial, industrial, and hospitals also play a role to ensure there is backup generation or storage. There is a need for multiple entities to play a role to ensure societal resilience. A utility can be part of those solutions.

Resources:

- Hawaiian Electric Resilience Working Group Documents: https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning/stakeholder-engagement/working-groups/resilience-documents
- NREL Threat Assessment Framework: https://www.nrel.gov/docs/fy19osti/74346.pdf
- Sandia National Labs Resilience Research: See Resources, Downloads section at https://energy.sandia.gov/programs/electric-grid/resilient-electric-infrastructures/
- The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices: https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198

2. If we look back to the experience of early adopters like New York, California, and Hawaii, what would be the first steps for Oregon to consider?

   Two dimensions to consider: (1) the scope that you want to incorporate into your integrated planning and (2) the relative sophistication of the analysis that you want and can conduct depending on available data, software tools, and methodologies.

   Consider your priority - could have a wider scope without as detailed/sophisticated a process. It's better to be good enough rather than being perfect.

   Consider the interrelatedness of different elements within the planning scope - e.g., resilience, reliability, DER integration, electrification, underlying asset condition and required grid modernization. Factor in how to consider the set of solutions on both the utility side and through communities and independent development. Understanding the interdependencies can help to understand how to increase the analysis sophistication.

3. Where can Oregon look for lessons learned?

   Places around the country furthest into IDP have been at it for around four years, maybe two plan cycles. California, Hawaii, New York, and Minnesota are into their second plans but each has a different set of objectives, none of which really accounted for resilience, which is an important consideration.

   In Michigan, the Michigan Commission started planning with a focus on reliability and resilience given major ice storms. Detroit areas economic downturn also led to abandonment of electric infrastructure, which created safety issues. Michigan commission started with looking at assets, thinking about reliability and resilience, and how IDP can encourage modernization and non-wires alternatives.

4. Are you aware of any programmatic practices that elevate resilience for a community that is identified as geographically isolated (end of the line)?

   With respect to remote communities, one of the things being considered is how to leverage microgrids to support those communities, rather than extending infrastructure lines. The projects are largely based on solar plus storage. Hawaii and PG&E have proposed projects. The project in Borrego Springs from SDG&E is now in operation (https://building-microgrid.lbl.gov/borrego-springs).

5. Tribes especially face unique threats because of the infrastructure and digital divide. For example, emergency services/response/supplies/stimulus, like with COVID, often doesn't reach tribal members because state/federal agencies and utilities aren't all well versed or connected to tribal agencies and service providers.

   In California, PG&E has a proposed decision as part of its community microgrid enablement program which includes outreach to tribal communities, as well as community choice aggregators. If the decision is adopted, PG&E has 60 days to develop a plan to engage with tribal communities, which could provide a framework to continue to work from.

   Bobby Jeffers' work in North Carolina may include insights into tribal community engagement.

   Blue Lake Rancheria: https://bluelakerancheria-nsn.gov/ - includes a microgrid project in northern California. Their website has information about resilience needs and opportunities.

6. Wealthier communities are more resilient to some threats in terms of access to resources. From a planning perspective, is there a way to integrate demographics and census mapping into threat analysis?

   Absolutely. Exelon Utilities (Pepco Holdings and Baltimore Gas & Electric) have targeted efforts to meet the needs of low and moderate income communities, including resilience and clean energy divide issues.

   Resource:

   - Clean Energy for Resilient Communities: https://www.abell.org/sites/default/files/reports/env-cleanenergy214.pdf

7. Doesn't uncertainty in load and DER adoption beyond three years tend to favor conventional utility solutions to change in load? How can scenario analysis be introduced into the planning process from the beginning?

   Uncertainty in load/DER forecasts beyond 3 years do not favor utility solutions which typically involve relatively large "step" increases in capacity at project completion to address full forecast need. For example, if a 10 year forecast indicates an increase of 20 MW over a particular substation's normal rating, then an additional transformer may be identified as a solution. But, that additional 20 MW transformer would be installed as soon as the existing transformer would experience an overload even at 2 MW. This is why utilities don't make large investments until they have greater certainty that the need will materialize.

   More to the question, this large "step" in capacity increase when there is uncertainty as to whether it is fully needed is precisely why the deferral value of NWAs are being pursued. In this example, an NWA could provide an incremental approach (proportionally scale the NWA over time to meet increased capacity needs) to mitigate the need for the transformer until it is clear that it is substantially needed or even permanently avoid the need.

   Scenario analysis is used as an input into the distribution planning process - this is similar to the California Energy Commission's base forecast and high/low forecasts for IRP. For distribution, a base granular forecast is developed and there may be a high and low scenario developed based around specific forecast sensitivities for new residential/commercial development, solar+storage and/or EV adoption in specific zip codes, for example.

8. How would you advise planning entities on how to engage with stakeholders to gain the best insight on the breadth of technology that can offer solutions (e.g., smart contract tech)? Is it pilot studies or more?

It's possible to develop a portfolio approach to thinking about a range of technologies (like an R&D portfolio). Recognize, though, that you can't implement everything. Some technology assessments may be limited to scouting potential, some will include pilots or lab testing.

Also look at what others are doing in great detail, possibly spending time with those implementation teams. Get a good understanding of where the technologies are - are they commercially viable or mature? What piloting or further development does it need to become commercially viable? Have an understanding of the technology adoption curve for newer technologies.

Resource:

- Pacific Northwest National Lab Modern Distribution Grid Report: https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx - See Volume II for Advanced Technology Market Assessment, with technology maturity curves for a range of grid mod technologies

9. I'm finding the community/point distinction and portfolio concept on Slide 18 helpful. How do you see the relationship between resilience, including those different solutions in the portfolio, and the distribution cost-effectiveness framework on slide 21?

   In terms of looking at overall solutions (slide 18), the economic dimension is being explored by the Grid Mod Lab Consortium. Joe Eto and Pete Larson are contributing to societal value studies and developing new methods for solutions.

   No one has exactly resolved how to tie the different components together. Solutions (e.g., microgrids) may have additional societal value (e.g., local jobs) that are not yet captured in cost-effectiveness tests. On the other hand, traditional distribution system upgrades (e.g., hardening the system) may have benefits beyond the area the specific project is serving. This is an emerging area and a number of issues still need to be resolved.

10. Are small nonresidential consumer groups a subject of particular conversation for DER given the diverse load small business represent?

    Small commercial businesses are often the largest customer group (by number) after residential customers but actual usage is proportionally less. They also are a heterogeneous group with different needs. How the solutions are looked at, particularly alternate solutions, is challenging. There are solution providers that look specifically at small commercial needs. Particularly with microgrids, in Hawaii, commercial property owners and strip malls are looking at providing multi-user microgrids for a customer with tenants, and considering how that interfaces with the electric grid and tariffs.

11. Can links to the various best practices/ studies underway being mentioned in the responses be provided to meeting participants?

    See above. Also, documents referenced in the presentation include:

    a. Minnesota PUC Integrated Distribution Planning Order: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BF05A8C65-0000-CA19-880C-C130791904B2%7D&documentTitle=20188-146119-01

    b. Xcel Energy Integrated Distribution System Plan: https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/IntegratedDistributionPlan.pdf

c. Hawaiian Electric Company Integrated Grid Planning Report: https://www.hawaiianelectric.com/clean-energy-hawaii/integrated-grid-planning

d. Pacific Northwest National Lab Modern Distribution Grid Report: https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

## Webinar #2 – Hosting Capacity Analysis

**Presented by Aram Shumavon, Kevala Analytics; Steve Steffel, Pepco Holdings; and Marc Patterson, Idaho Power**

**Wednesday, May 6, 2020 from 9:30 - 11 a.m. Pacific**

**Presentation abstract**

Hosting Capacity Analysis is an analytic framework that can inform developers, customers, and the electric utility of the remaining capacity to accommodate distributed energy resources on the distribution system. Maps showing Hosting Capacity and any restrictions help all stakeholders better plan for future systems.

Presenters will offer an overview of approaches to hosting capacity analysis and how those may be applied in Oregon.

**Speaker bios**

Aram Shumavon is the founder and CEO of Kevala, a San Francisco based data and analytics company focused on the electricity sector. An economist by training with an AB in economics and public policy from the University of Chicago, he studied the market implications of transitioning natural monopolies to competitive markets. After academia Mr. Shumavon worked for over a decade at the California Public Utilities Commission where he was an advisor to Commissioner Geoffrey F. Brown and worked on market design and transition issues in the telecommunications and energy industries. In 2014 Mr. Shumavon founded Kevala, a platform-based data and analytics company that provides a broad spectrum of data and analytics services related to the energy transition.

Steve Steffel is the Manager of Regional Capacity Planning – Distributed Energy Resources, focused on the modeling and integration of various types of generation into the distribution grid. PHI is an Exelon Company and the parent company of Potomac Electric Power Company (Pepco), an electric utility serving Washington, D.C. and suburban Maryland; Delmarva Power, an electric and gas utility serving Delaware and the rest of the Delmarva Peninsula; and Atlantic City Electric, an electric utility serving southern New Jersey.

Marc Patterson is an Engineering Leader with Idaho Power.

**Presentation slides** can be viewed at the following links:

Presentation – Nick Sayen – https://www.oregon.gov/puc/utilities/Documents/DSP-Webinar2-PUC-Presentation.pdf

Presentation – Aram Shumavon – https://www.oregon.gov/puc/utilities/Documents/DSP-Shumavon-Presentation.pdf

Presentation – Steve Steffel – https://www.oregon.gov/puc/utilities/Documents/DSP-Hosting-Capacity-SSteffel.pdf

Presentation – Marc Patterson – https://www.oregon.gov/puc/utilities/Documents/DSP-Hosting-Capacity-MPatterson.pdf

**Webinar video**

A recording of the session can be viewed at the following link:

https://oregonpuc.granicus.com/MediaPlayer.php?view_id=2&clip_id=503

**Stakeholder questions**

*Please note that questions and answers may have been edited for clarity and brevity. Unfortunately presenters were not able to address all questions from this session.*

1. How should we weigh the value of freshness and/or granularity of the analysis with the cost/time of resources that it takes to perform it? Is anyone doing this well?

   One of the things stakeholder processes are good at surfacing is where the strongest interest likely is coming from - recommend making sure that stakeholders are surfacing concerns around this issue. The dialogue that happens between utilities and end users can allow for better understanding of those tradeoffs.

   Oregon may choose for lower fidelity relative to, for example, an interconnection analysis, in exchange for fresher updates. The kinds of analyses that can be updated frequently are not likely full power flow analyses. Or you may decide that a more specific analysis that takes longer is appropriate.

   The stakeholder process has to inform this decision to determine the value that is relevant to the community.

   Please note that there will be complaints about the tradeoffs and decisions made. Fresh queue information is important to understand from the IPP side where you don't want to invest time and energy if you're late in the line and few are able to interconnect.

   Hawaiian Electric Company updates their data on a nearly daily basis, but that doesn't necessarily mean the same thing for an entity trying to connect utility scale projects elsewhere.

2. Are you aware of any 'tools' incorporating retail market dynamics/changes to (e.g., TOU, DR, Direct Access, Smart Contract -- Transactive Energy) and the impact on hosting capacity analysis (HCA) outputs? It seems that currently HCA solely focuses on grid assets and not necessarily how a given asset responds when combined with market behaviors.

   This question starts to move in the direction of distribution planning and non-wires alternatives, which is less interconnection focused than HCA. Of course, a resource that may be able to interconnect at a lower cost (or larger size) in exchange for behaving differently than "standard resources" are modeled is a sort of middle path between these issues. There is a significant amount of work being done on how devices can or must act that will affect how many of them can be interconnected quickly and at a low cost. Many workshops are invested in these issues in California and elsewhere - see Rule 21 interconnection efforts for more information.

3. How do utilities typically define the term "circuit node"?

   Every system software has its own definition. It can be a piece of equipment, or the end of a piece of equipment. There isn't one single definition.

4. Are there techniques for trend projection of hosting capacity to assess future states weeks or months ahead?

It's absolutely possible to do trend analysis on hosting capacity but it is important to realize there are many factors in play, including market dynamics, that can be highly volatile. A better investment in time and energy may be on establishing frameworks for socializing or otherwise sharing costs so that market distortions don't occur when those hosting capacity limits are hit.

5. Why is visualization of hosting capacity so critical? Does it vary based on end use?

   Visualization (especially geospatial mapping) is a shorthand mechanism for conveying a lot of locational information intuitively and quickly. Much effort would have to be invested in attempting to provide for all of the possible end uses that would have to be incorporated that can be simplified to "I went to a place on a map and saw X."

   I don't want to suggest that visualization is all that is needed. It is not. Red, Yellow, and Green, as an example, represent helpful additional information beyond merely identifying the circuit in question. There are a lot of assumptions that are "baked in" to those colors that make them less flexible than more robust datasets at the same piece of grid equipment.

6. How are customer privacy concerns taken into consideration with the high definition maps? Especially as you consider providing more information on the generation locations at the building level.

   It is important to be mindful of the fact that privacy is only one concern. Market sensitive data that might result in higher prices for the same services are also important to be mindful of, as is critical energy infrastructure information (CEII), although CEII explicitly is not concerned with the location of resources but rather some aspects of their operating characteristics.

   One thing to be mindful of with PV is that it is all discoverable from satellite imagery, or in the case of backup generators, may require emissions permits or at least publicly available building permits. So the location of generation information is not as constrained as, say, load data. Some states actually require the address of NEM customers and their system information to be publicly available under FOIA because they are receiving a government benefit - so these kinds of issues can be sliced different ways.

   Every state has its own unique customer privacy laws to be followed, which makes it difficult to generalize. But, in general, the industry is moving toward frameworks like differential privacy rather than surfacing hard numbers (e.g., the "15X15 rule" or geographic aggregating requirements).

7. Is standalone storage analyzed differently than generating resources, given that it can function as a generator or a load?

   How to handle storage (standalone or bundled with PV) is highly variable because it is not constrained by fuel availability in the same way solar PV is dependent upon the sun. This means that typically it's treated as an incremental addition to the amount of PV or expected that it will consume when aggregated demand is highest.

   In practice this behavior can be limited by system design choices (e.g., a single, shared set of inverters for both solar and storage), contracting choices (e.g., agreeing to a particular set of charge limits for a capacity payment), or as a condition of interconnecting at a lower cost (which is effectively a capacity payment). In the end most of these decisions are part of a regulatory process and well-defined in that context.

8. Is Idaho Power providing a visualization tool?

   Not at this time

9. It seems like the beneficiary(ies) of a granular, routinely refreshed hosting capacity analysis might not be the same people who would historically be paying for the development of such tools, which seems like an important aspect for any new requirements to recognize. These studies exceed what legacy customer connection planning studies might require and impose costs to the utilities that customers will pay additional for, somehow, unless other methods for map development are considered.

   Comment is noted for consideration by Oregon PUC staff.

Unaddressed questions:

10. Does PEPCO use AMI data in hosting capacity analysis?

11. If we had an advanced communication network couldn't we allow both "firm" and "as available" hosting capacity?

12. Is the stochastic hosting capacity method also applicable to DERs other than PVs?

13. What is the basis of the 500 kW load trigger on slide 10 in Pepco Holdings' presentation?

14. Can you provide an example of a synchronous DER?

15. Can you define "stiff feeder" -- presume that's related to short circuit strength

16. If you had to choose between using hosting capacity for utility planning investments and using hosting capacity to provide transparency for DERs…which would you choose?

17. Are there any examples of failures in hosting capacity? Has anyone learned any hard lessons to date?

## Webinar #3 – Distributed Energy Resources Valuation

**Presented by Debra Lew, Debra Lew LLC; and John Shenot, Regulatory Assistance Project**

**Friday, May 8 from 1:30-3 pm Pacific**

**Presentation abstract**

Distributed energy resources (DERs) could have significant influence in distribution system planning, costs, and reliability. Without focused planning, the value and functions of DERs may not be optimized. In this webinar, John Shenot of the Regulatory Assistance Project and Dr. Debra Lew of Debra Lew LLC will present on the policies, regulations, and approaches that shape DER valuation to offer insight into what could be applicable for Oregon.

**Speaker bios**

As a senior advisor to the Regulatory Assistance Project (RAP), John Shenot advises utility commissions and environmental agencies on public policy best practices. He has authored or co-authored a wide variety of publications, including a 2019 guidance document for public utility commissions in restructured states on integrated distribution system planning and a 2018 report for the International Renewable Energy Association on global best practices for power system planning. Mr. Shenot came to RAP after serving as policy advisor to the Public Service Commission of Wisconsin from 2008 to 2011 and electric utility specialist for the Wisconsin Department of Natural Resources for ten years prior to that. Mr. Shenot received a bachelor's in engineering from the University of Maryland and a master's in resource policy from the University of Michigan.

Dr. Debra Lew is an independent consultant with 28 years of experience in the energy sector. Previously she served as Technical Director at GE Energy Consulting, focusing on utility integration of wind, solar and DERs. Before that, she spent 16 years at the National Renewable Energy Laboratory (NREL), where she initiated and led the Western Wind and Solar Integration Study, examining impacts of high penetrations of wind and solar in the Western Interconnection. She also worked with Hawaiian Electric on integrating high levels of wind and solar in Hawaii. She has a B.S. from MIT in Electrical Engineering and Physics and a Ph.D. from Stanford in Applied Physics.

**Presentation slides** can be viewed at the following links:

Presentation – Nick Sayen – https://www.oregon.gov/puc/utilities/Documents/DSP-Webinar3-PUCPresentation.pdf

Presentation – Debra Lew – https://www.oregon.gov/puc/utilities/Documents/DSP-LewPresentation.pdf

Presentation – John Shenot – https://www.oregon.gov/puc/utilities/Documents/DSP-ShenotPresentation.pdf

**Webinar video**

A recording of the session can be viewed at the following link:

https://oregonpuc.granicus.com/MediaPlayer.php?view_id=2&clip_id=514

**Stakeholder questions**

*Please note that questions and answers may have been edited for clarity and brevity.*

1. The tendency is to think of "cost-effectiveness" as a bright line which qualifies or disqualifies a certain DER. In practice though, a particular measure might not be cost-effective on its own, but could be cost effective as part of a portfolio. What are your thoughts about "bright line" cost-effectiveness?

   Combining DERs could lead to greater value than the sum of the parts. This quantification, however, is still an emerging area. We can learn lessons from energy efficiency. Oregon may want to take an approach to ensure that a portfolio of DERs are cost-effective, recognizing that value is time and location dependent.

2. Where do you think the best authority (e.g., DSP rulemaking) should outline the specifics of normalizing valuation across different DERs? Or is it up to the individual utility to determine which studies and values to use for valuation? Which authority sets those costs?

   For regulated utilities, the Public Utility Commission has the primary authority over how programs and costs are evaluated. For unregulated utilities, the governing board is the authority. In both cases, the Legislature or another agency might also have authority. In Minnesota, for example, the Department of Commerce developed the value of solar methodology.

3. How would the ability to orchestrate putting power into the grid and taking power off the grid impact DER valuation?

   With a DER, the utility is avoiding the need to provide these services. The value depends on the grid services provided and the costs avoided. The value stream approach can be leveraged.

4. Would like a bit more clarity about "non-wires" which means something different in transmission planning -- is "non-wires" for DER the same as "customer side" vs "distribution side"?

   "Non-wires" in Debbie's presentation referred to infrastructure on the distribution system, or programs that can provide specific types of services at specific locations at specific times on a contractual basis, which the utility typically does to defer some kind of distribution system upgrade (e.g., [Brooklyn Queens Demand Management Program]).

   Non-wires solutions are not necessarily on the customer side or distribution system. It could be very broad.

5. Would valuation for resilience measures in locations subject to supply / service interruptions be included in Risk Hedge?

   Resilience and the potential to go into a whole new area of having services provided absent the utility providing services is a new emerging area. Valuation of resilience is where we are going in the future.

6. What are some good examples of states/pilots that look at societal value of DER as a primary measure? (as opposed to utility/participant value)

   Vermont is one of the few states that use the societal test as the primary cost-effectiveness test.

   A lot of states have a hybrid test - using the TRC or UCT and adding in some societal values. For example, Massachusetts adds in an assumed cost of carbon that is higher than the regulated cost of carbon.

The best examples are hybrids that can be applied to several DERs consistently.

7. Are there any examples of how societal resilience values can be monetized based on the relative disruption risks (distance/route from loads to capacity as well as natural hazards) of specific communities?

(John Shenot) The entire subject of resilience value is relatively new. There is a fairly limited body of research on the topic, but I don't know of any papers or reports that directly address this question or any real world examples of monetizing the value (e.g., in a regulatory docket).

For value of resilience looked at broadly, Wilson Rickerson and his colleagues at Converge wrote a paper for NARUC on the current state of play in what states are doing: The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices (2019). They found "The value of resilience has played a limited and largely qualitative role in the regulatory proceedings reviewed" but did summarize some recent quantification case studies from outside of regulatory dockets.

A big team of researchers at the National Renewable Energy Laboratory wrote a more technical report on the topic in Adapting Existing Energy Planning, Simulation, and Operational Models for Resilience Analysis (2020). The latter cites a number of relevant papers and may be especially useful in the context of distribution system planning.

Note that the value of resilience is not entirely societal and in some instances a resource installed for resilience purposes may have no or almost no societal value. In cases of resilience, the electric utility may not see any additional revenues or utility system benefits if the customer is resilient, so the value of these resilience investments in a UTILITY cost test would be zero. Thus the importance of making sure everyone is on the same page in terms of "value to whom."

Having zero utility system value does not, however, equate to "not relevant to utility planning." Resilience investments are made because the utility system, as amazingly reliable as it is, is not 100% reliable. If it was 100% reliable, customer investments in DERs would have no resilience value. So the value of resilience is inextricably tied up with the quality of the utility's system plans and the reliability of their system.

Investments by the utility that boost reliability actually reduce the resilience value of DERs. A failure to invest in a reliable system increases resilience value. That's why I think it is appropriate to think about resilience value in the context of distribution system planning. It is a participant and societal value, but it is a value that depends on and derives from how reliable (or not) the utility system is.

(Debra Lew) I agree the idea of resilience value is a new area of research. I tend to think of resilience as an extreme event that doesn't typically get planned for today, like the power shutoffs due to wildfires in CA or the Superstorm Sandy. In that context, the value of loss of load could be used as a starting point. LBNL has their Interruption Cost Estimate calculator and this could be a start. I think you would need to revise this to account for the long duration of the event, however. It may be manageable for many customers to have several hours without power, but not manageable to go several days without power. I'm not sure how you go about taking that into account but I would think it would be important.

8. For the immediate grid needs where there wasn't enough time for solicitations, would a DER program be able to meet those needs or does the utility require greater assurance that the need will be met?

(John Shenot) The answer to this question, I think, is it depends on the utility system need. When a utility experiences equipment failure, there may be no other practical option than a replacement utility infrastructure investment. The same may be true if the utility has an unanticipated capacity shortage looming in the very near future. In some of those cases, a non-wires solution won't work just because of the immediate nature of the need and the time it takes to roll out or scale up a DER program or procurement. However, utilities can foresee a lot of their upcoming system needs with ample time to evaluate all solution options, including the use of DERs, and solicit bids for meeting needs. Most DERs can be installed fairly quickly, and some DER programs can be scaled up fairly quickly if the benefits make it attractive enough. This is one of the primary reasons to institute a transparent distribution system planning process: to anticipate needs while there is still enough time for a range of potential solutions to be considered and implemented.

(Debra Lew) I agree that it depends on the need. If it is a need for capacity I think you either want a contract with the parties who will provide the service with M&V and penalties for non-provision, or you want a dynamic enough demand curve such that you can get demand to curtail itself based on prices or compensation. For the latter, I'm thinking you could statistically count on some amount of participation in a peak time rebate program (and I suggest you need to offer a good amount of compensation to make it worth people's while) or other DR type program (air conditioners or EV charging, etc.).

9. With regard to the slides on PG&E's Distribution Investment Deferral Framework what was the project that won and was implemented?

   Please see the Approval for PG&E's Advice Letter requesting approval to issue competitive solicitations to procure DERs for distribution deferral.

   https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5435-E.pdf

   PG&E's 2019 Distribution Investment Deferral Framework Webpage: https://www.pge.com/en_US/for-our-business-partners/energy-supply/electric-rfo/wholesale-electric-power-procurement/2019-didf-rfo.page?WT.mc_id=Vanity_rfo-didf&ctx=large-business

   PG&E's 2020 Distribution Investment Deferral Framework Webpage: https://www.pge.com/en_US/for-our-business-partners/energy-supply/electric-rfo/wholesale-electric-power-procurement/2020-didf-rfo.page?ctx=large-business

10. Has any state or utility determined that it's regressive to put societal value in the utility compensation?

   (John Shenot) I don't know if any state or utility has framed their decisions in those terms, but this is the essence of the debate about which cost-effectiveness tests should be used as the primary test for decision-making, and whether societal value should be considered when establishing compensation for DERs. As I said on the webinar, few states have adopted the SOCIETAL cost test as their primary test for energy efficiency programs (or other DER programs). The rationale I hear most often is that the utility is chartered to provide an essential public service, ELECTRICITY. It isn't chartered to satisfy all of society's needs, and if a DER has societal value than any compensation for that value should come from some source other than the utility; tax incentives, for example. To do otherwise could be considered regressive, because if a customer is compensated for societal value by the utility, then some utility customers who are not as well-off as the participant will foot the bill and be worse off.

   The flip side of this argument also gets made frequently. In some states, the "public interest" that utilities are chartered to serve is interpreted more widely and isn't limited to delivering electrons to customers. Legislatures have asked or required utility customers to pay for other types of societal benefits, for example through low income customer subsidies, economic development rates. They've told regulators to consider a societal cost of carbon in decisions. That sort of thing. The idea of putting societal value into utility rates, or DER compensation, is not at all unprecedented and some clearly are okay with it.

## Webinar #4 – Non-wires Alternatives

**Presented by Jason Prince, Rocky Mountain Institute; and Mark Luoma, Consumers Energy**

**Wednesday, May 13 from 1:30-3 pm Pacific**

**Presentation abstracts**

This first presentation will provide an overview of non-wires alternatives, including their value proposition, market status, and barriers and opportunities for scaling.

The second presentation will cover the background of Consumers Energy's non-wires solutions efforts, the initial pilot at Swartz Creek, site selection process for a second pilot location, the current pilot at the Four Mile substation and activities underway to develop non-wires solutions capabilities.

**Speaker bios**

Jason Prince has spent the last 9 years working in energy markets. Most recently, as a Manager at RMI he has led projects focused on innovation in utility business models, planning, and procurement. Prior to RMI, Jason worked in structured finance at SolarCity and research at energy financial services firm Karbone.

Mark Luoma is a Senior Program Manager at Consumers Energy, headquartered in Jackson, Michigan. As part of the Demand Side Management organization, Mark focuses on Residential Demand Response Pilot Programs and has supported the Non-Wires Solutions pilot effort since 2017.

**Presentation slides** can be found at the following links:

Presentation – Nick Sayen – https://www.oregon.gov/puc/utilities/Documents/DSP-Webinar4-PUC-Presentation.pdf

Presentation – Jason Prince – https://www.oregon.gov/puc/utilities/Documents/DSP-Prince-Presentation.pdf

Presentation – Mark Luoma – https://www.oregon.gov/puc/utilities/Documents/DSP-Luoma-Presentation.pdf

**Webinar video**

A recording of the session can be viewed at the following link:

https://oregonpuc.granicus.com/MediaPlayer.php?view_id=2&clip_id=526

**Stakeholder questions**

*Please note that questions and answers may have been edited for clarity and brevity.*

1. Are you saying that these solutions are solutions specifically to load growth related investments or all T&D investments?

Non-wires solutions can address distribution system issues beyond load growth (particularly if load is short and spiky). There should always be selection/screening criteria for when a non-wires solution should be applied. Screening criteria may be flexible by project and temporally.

2. Slide 6 of RMI's presentation: Aggregated load remains flat? Investments in flat areas are insinuated, but may not be occurring?

   The data are aggregated based on national data from EIA. Regional variations occur, of course, but in aggregate, load has been relatively flat compared to an increase in capex on the distribution system.

3. Does the utility savings on "wires" investments actually 'help' the utility without performance based ratemaking? That is, do you also have to change the incentive to maximize capital build to make it 'beneficial' for the utility?

   The quick answer is - you may need some type of performance-based regulation and some degree of change to the traditional cost of service framework to get utilities' business models in line with spending less money.

   An issue with shared savings mechanisms is that the utility may not be motivated to pursue the non-wires solution unless there is a massive amount of savings possible. Performance incentives can help to fill this need.

4. Any estimates of how much new distribution "wires" investment (other than standard O&M) is needed per year relative to total utility revenue requirement? 1%, 5%, more?

   (from the audience) At the Yosemite Policymakers Conference, CPUC commissioner Martha Guzman Aceves mentioned that the largest growth in utility costs presented for rate recovery were distribution costs - this is post CA DRP. Costs include grid-scale distributed energy resources (DERs), supervisory control and data acquisition (SCADA)/ distribution automation (DA), DER management systems (DERMS), advanced data management systems (ADMS), etc.

5. What is the peak load rating for Swartz Creek? It would help to get a sense of how much 1.5 MW of relief would provide.

   It was about 23-25 MW.

6. How have customers - residential or C&I - responded to more direct messaging on the reason for the differential non-wires solutions incentives and the need for this work?

   In the quick launch, there was a good response in a short amount of time. Working through trade allies has also been good. It's too early to be overly confident about impact, however.

7. To what extent are you using artificial intelligence/machine learning and Data Science along with advanced metering infrastructure (AMI) to segment customers and their propensity? Or is the segmentation based on other metrics? If so, which ones?

   The internal customer analytics team at Consumers Energy has worked together to conduct propensity modeling across programs, so customers have been segmented from a propensity perspective. Messaging is targeted to all customers that may participate in a DR program, and then more focused messaging is leveraged to encourage participation in AC cycling and/or peak time reduction programs.

8. Can you say more about what DER solutions were used in both pilots? A combination of energy efficiency and demand response? Were there any DERs solar/storage automated load control behind the meter in addition to those?

The pilots included energy efficiency and demand response. No solar/storage at this time, but it is something Consumers Energy is looking into. The company is running a residential battery storage pilot not associated with non-wires solutions at the moment.

9. How should Oregon's utilities and stakeholders approach the development and application of screening criteria for non-wires solutions?

   The best way to develop criteria is through stakeholder processes. The utility knows most, so they may want to lead the discussions. Screening criteria should be tailored to the utility's specific needs. Screening criteria should be considered flexible - both on a project basis (e.g., don't exclude projects if it is $1 over an economic threshold) and temporally to be updated as more experience is gained.

## Webinar #5 – Load Forecasting

**Presented by Ben Sigrin, National Renewable Energy Laboratory**

**Thursday, May 14 from 9:30-11am Pacific**

### Presentation abstract

Mr. Sigrin will present on the topic of 'Forecasting load on distribution systems with distributed energy resources.' His talk will include a discussion on methodology for forecasting DER adoption, its application in the context of distribution system planning, and common pitfalls.

### Speaker bio

Ben Sigrin is a research engineer in the Distributed Systems and Storage Group at the National Renewable Energy Laboratory (NREL). His research interests include capacity expansion modeling with a focus on adoption of distributed energy resources, risk and decision-making, and customer behavior. He is currently the principal investigator of a 3-year DOE-funded project to study drivers of residential adoption of rooftop solar. He is also the technical lead for NREL's Distributed Generation Market Demand Model, or "dGen", an agent-based model to forecast distributed energy resources deployment.

**Presentation slides** can be found at the following links:

Presentation – Nick Sayen – https://www.oregon.gov/puc/utilities/Documents/DSP-Webinar5-PUC-Presentation.pdf

Presentation – Ben Sigrin – https://www.oregon.gov/puc/utilities/Documents/DSP-Sigrin-Presentation.pdf

### Webinar video

A recording of the session can be viewed at the following link:

https://oregonpuc.granicus.com/MediaPlayer.php?view_id=2&clip_id=528

### Stakeholder questions

*Please note that questions and answers may have been edited for clarity and brevity.*

1. How granular in terms of impacts on the distribution system can the NREL tool model?

   DGen is an agent-based model, which means NREL develops agents that represent different statistical clusters and possible consumer types. This allows simulations at the national or regional level but lacks spatial precision for the household or building level. For distribution system planning, construct agents should be constructed to represent individual households, which is more difficult and requires more work to build up the databases, but allows modeling of impacts to individual feeders.

2. Are there any proposals to provide DER data as a service that can allow for greater visibility into the system?

   Not aware of any tools, but it depends on the utility's technical capability, communication devices, internet of things, etc.
   Utilities in California use Bass diffusion modeling to forecast the trajectory of solar PV adoption.

3. Does the nature or type of DER matter when choosing a type of forecasting model?

   It's somewhat unknowable but one way to think about it relates to the amount of experience with the technology. Emerging technologies can lack enough data to calibrate models - which might be an argument for using program-based data to model. For technologies that are more mature (e.g., solar), we have enough information from past trends to do customer-level modeling.

4. Is any utility or regulator using DMV data for forecasting the adoption of electric vehicles by neighborhood or demographic groups?

   Yes, using DMV data is a method used. PGE has used DMV registration data to calibrate a bottom-up propensity model to predict locational EV adoption. You can read details in PGE's 2019 IRP and TE Plan.

5. Are there cases of utilities being required and/or able to predict adoption according to demographics, and sharing this publicly?

   Probably not required, but many utilities are electing to use more detailed modeling. Use of personally identifiable information limits publicly sharing this type of data.

6. Is the propensity to adopt model, a regression type model?

   It is commonly a regression model but it could also be other types of models can also be used such as a clustering model, random forest models, and other data-driven methods.

7. Are there any forecasting methods that incorporate building-level characteristics?

   It's an emerging methodology that NREL is exploring. Permitting data can provide insight if it is reliable. Potentially, remote imaging might be used for understanding the age of the roof. I'm not aware of a remote method to determine electrical code compliance - you would likely need to use a survey to understand that.

8. Is there enough uptake of battery storage systems to do good forecasting at the current time?

Yes, I believe so. However, there are not as many existing studies on consumer adoption of battery storage as for distributed solar, so we know less about the drivers of distributed storage adoption than we do about distributed PV.

9. Are there any plans to include EE - DR in the DGen tool?

   Yes

10. The slide on customer economics adoption modelling appeared to assume a 'time based rate' that had a negative impact on project economics. Has NREL looked at the impact of time of use rates that encourage adoption of solar or solar+storage?

    In most power systems peak demand is non-coincident with solar generation, thus ‘on-peak’ TOU prices occur during hours of lower solar generation, which is why many TOU tariffs discourage solar-alone economics as compared to volumetric tariffs. The combination of solar with storage changes the dynamics—with storage, a S+S system can charge during low price periods and discharge during higher prices. This may negate the non-coincidence issue. In general, the value of storage increases when there are larger differences between the peak and off-peak price, i.e. there is more opportunity for energy arbitrage.

## Webinar #6 – Best Practices for Community Engagement

**Presented by Oriana Magnera, Verde; and Charity Fain, CEP**

**Wednesday, May 20 from 1:30-3 pm Pacific**

**Presentation abstract**

This presentation will focus on best practices of community engagement.

**Speaker bios**

As Verde's Energy and Climate Policy Coordinator, Oriana leads Verde's work on energy and climate policy. Her background includes a focus on deepening organizational commitment and engagement with environmental justice and issues for low-income and marginalized communities in the energy space. She has facilitated workforce and economic development and community solar workgroups for the multi-state DOE Sunshot grant (Solar Plus) and facilitated a workgroup for the Oregon Public Utility Commission community solar docket (AR 603) on low-income program elements.

Charity has over 25 years of experience building stronger communities in the US and around the world in fields such as climate justice, women's human rights, civil society development and independent media. As the Executive Director at CEP, she leads the organization and ensures the strategic direction is implemented. Prior to CEP, Charity worked as Executive Director at the City Club of Portland, keeping Oregonians informed about pressing public issues. Before moving to Portland in 2007, Charity also served as the Country Director for Internews Network in Kyrgyzstan working to build stronger journalists, radio stations and public interest television. Charity has a BA in International Relations from The American University in Washington, DC and also speaks Russian.

**Presentation slides** can be found at the following links:

Presentation – Nick Sayen – https://www.oregon.gov/puc/utilities/Documents/DSP-Webinar6-PUC-Presentation.pdf

Presentation – Oriana Magnera & Charity Fain – https://www.oregon.gov/puc/utilities/Documents/DSP-Magnera-Fain-Presentation.pdf

**Webinar video**

A recording of the session can be viewed at the following link:

https://oregonpuc.granicus.com/MediaPlayer.php?view_id=2&clip_id=535

**Stakeholder questions**

*Please note that questions and answers may have been edited for clarity and brevity.*

1. You've mentioned the labor and time intensive aspects of community engagement, any thoughts (at the appropriate time in the presentation) about "scaling out" to cover the very broad and diverse set of communities (both geographic and by other groupings) across the state

   Verde is starting to do statewide work, but no one organization can effectively work across the state. Work across the state will need many partnerships because you need to be in the community and part of the community to effectively organize the community. It's important to build lots of relationships in different communities with lots of community-based organizations. It will take time and trust-building. Building networks is also important.

   Community engagement is very underfunded. If you value bringing in communities, you need people who know how to do it and skilled facilitators. You can't expect to do this without budget behind it. If we want to value this work, then money has to go behind the value too.

2. Most of the presentation has focused on residential customers. Would community engagement differ for different customer classes such as small businesses? Do either of you have any examples of community engagement with small businesses?

   It's not that different because businesses still have people working in them. It's important to recognize that they are a different rate class, and face different issues, but engagement would be similar.

   Small businesses are a different definition of community, but still a community. We still need to listen and build trust and make it easy to interact and meet the community where it is.

3. Ongoing question for staff and the OPUC: How can this DSP process and OPUC work in general incorporate what we learned today?

   Staff is working to incorporate lessons in forming draft recommendations for stakeholder and Commission consideration.

## Webinar #7 – Distribution Planning Regulatory Practices in Other States

**Presented by Lisa Schwartz, Lawrence Berkeley National Labs**

**Thursday, May 21 from 1:30-3:00 pm Pacific**

**Presentation abstract**

Lisa Schwartz will present on the variety of ways states are engaging in distribution system planning by electric utilities. Her presentation will include example public utility commission requirements and regulatory practices, with links to commission orders and utility filings across the country.

**Speaker bio**

Lisa Schwartz is Deputy Leader of the Electricity Markets and Policy Department at Berkeley Lab. She manages work spanning utility regulation, electricity system planning, energy efficiency and other distributed energy resources, and leads training for states on distribution system planning. Previously, she was Director of the Oregon Department of Energy, where earlier in her career she was a Senior Policy Analyst. At the Oregon Public Utility Commission for seven years, she was staff lead on resource planning and procurement, demand response, and distributed and renewable energy resources.

**Presentation slides** can be found at the following links:

Presentation – Nick Sayen – https://www.oregon.gov/puc/utilities/Documents/DSP-Webinar7-PUC-Presentation.pdf

Presentation – Lisa Schwartz – https://www.oregon.gov/puc/utilities/Documents/DSP-Schwartz-Presentation.pdf

**Webinar video**

A recording of the session can be viewed at the following link:

https://oregonpuc.granicus.com/MediaPlayer.php?view_id=2&clip_id=537

**Stakeholder questions**

*Please note that questions and answers may have been edited for clarity and brevity.*

1. Has a "cost" for air emissions been quantified? Might that be the Societal Cost of Carbon?

   LBNL recently published a study on non-energy impacts that addresses this issue: https://emp.lbl.gov/publications/applying-non-energy-impacts-other.

2. How have initiatives such as green button and 3rd party authorization for data sharing been handled?

   One state (possibly Rhode Island) specifically addresses this.

3. Are states considering how advanced communications networks could help optimize distribution networks? For example, orchestrate and control, as much as possible, DER to complement each other and avoid capacity issues and essentially expand hosting capacity and support NWAs.

   Yes, this is a major issue. You want the consumer/home/business to be interacting with the grid either through a price signal or autonomously and there are different ways to make DERs interactive with the grid. It's also increasingly important to consider how DERs within a site integrate with each other. Both communication issues (DERs communicating with each other, and DERs communicating with the grid) are major issues for the lab and others.

4. Going back to those slides about specific state guidelines and state-specific utility filings, are there examples you can point to of regulators or utilities using decarbonization and/or renewable resource integration as planning priorities?

   Most, if not all, states are considering this issue and have requirements for distribution plans or grid modernization plans to include decarbonization or renewable resource integration.

5. In the evaluation of distribution system plans, are other states looking at the customer groups in more detail with regard to equity? For example, looking at areas where there has been historic underinvestment in distribution by the utility or negative impacts of the utility system?

   Washington State, when they started their distribution planning proceeding, equity was a really big part of that, they are also addressing equity in a broader way. Maryland has also looked at equity specifically. LBNL is considering a report on this issue as well. It's reasonable to look at different customer groups and how different investments in technologies would benefit those groups.

6. Can you also speak to the relationship between the capacity map updates and interconnection queues? I know in CA some issues arose when maps showed capacity metrics publicly; however, they did not reflect proposed projects in the interconnection queue.

   Hosting capacity isn't covered in this presentation, but you could refer back to webinar 2. The important thing is that the Commission should establish its use cases for hosting capacity given that it is a major effort. California is using hosting capacity maps specifically for interconnection and to help streamline interconnection. Whereas, if you're looking for heat maps to better understand where DERs can be installed, you may need less detailed and costly analysis. Make sure you include interconnection queues, not just connecting DERs, in the hosting capacity analysis.

7. California is requiring all IOUs to include avoided transmission costs in the avoided cost calculator. Are other states considering similar methods to fully value DERs as part of the DSP?

   Yes, Rhode Island would be a good example.

8. Related to equity is the quantification of work in energy utility capital projects performed by minority, women, and veteran owned businesses.

   States may be, but I'm not aware of specific examples.  This could be reflected in the non-price solicitation rules itself rather than in the distribution system plan

9. Does the term “multiplier effect” come up in these studies being referenced as a describer of the economic impact on communities where distributed resources work, including wires and non-wires related, is located?

   This may also be considered a non-price criteria in the solicitation for non-wires alternatives.

10. I’m a large regional energy customer (City of Portland – Fleet and Facilities). I’m curious if and how emerging DSP regulation is addressing funding for new types of energy assets/infrastructure, such as charging at the scale that we will need to convert our fleet – which I imagine will CREATE a need for feeder upgrades and distribution investment, not defer this need.

    Cost is a substantial barrier for us, so these are not investments that we could fund alone, but we also recognize that it’s new infrastructure that ratepayers shouldn’t necessarily have to subsidize given that we might be the exclusive beneficiary of these new asset and infrastructure build-outs. At the same time, we’re working in service of the same climate goals and values that I presume many utility customers and OPUC constituents share, and hopefully our investments will help pave the way for others to go green, as well.

    What is the OPUC’s vision for enabling affordable grid investment that promotes positive social change?

    Question is noted for OPUC's consideration and future follow up.

11. What are the time frames between - say - DDOR and actual RFP?   I asked because in many of these cases the timeframes are so short that it creates some issues with the kind of responsive projects.  Apropos the Moorpark Goleta capacity RFP through SCE only received responsive battery capacity but not really any generation (which would be a problem if the grid went down for long) because of local code restrictions and unsuitable land for solar or generation locally.  This could have been improved if local communities had more time to gather a portfolio of suitable sites for generation AND storage and EE/DR; however, in the tight time frame they couldn’t get it done.

    Points are well taken, but I am not an expert at the project level.  EPRI has a series of guidebooks for utilities on, for example, how to view storage.  Within the solicitation, you can ask for hybrid projects, or even include a preference for certain hybrid projects.  There are aggregators that could be responsive.

    Upfront stakeholder engagement with providers and customers can also help understand whether an RFP could receive responses or whether requirements should be described a certain way.

12. More detail on potential benefits of improved distribution system planning are available in the GridWise® Transactive Energy Framework https://www.gridwiseac.org/about/publications.aspx. GridWise® Decision-Maker's Transactive Energy Checklist, is also being updated and a new 2020 version should be published within the next month or two.

    Comment is noted.

## Webinar #8 – Minnesota's Experience with Distribution System Planning

**Presented by Tricia DeBleeckere, Minnesota Department of Commerce**

**Wednesday, May 27 from 1:30-3:00 pm Pacific**

**Presentation abstract**

Tricia DeBleeckere will present an overview of Minnesota's Integrated Distribution Planning process, including lessons learned as Minnesota has conducted its process.

**Speaker bio**

Tricia DeBleeckere is currently a Planning Director with the Minnesota Department of Commerce in the Energy Regulation and Planning Division. Previously, she spent 12-years as staff and Commission advisor to the Minnesota PUC leading the creation of the state's distribution system planning requirements. Prior to the Commission she worked for eight years as a consultant to the energy and manufacturing sectors. She is currently Co-Chair of the Organization of MISO States' DER Workgroup endeavoring to integrate DERs in the MISO region.

**Presentation slides** can be found at the following links:

Presentation – Nick Sayen – https://www.oregon.gov/puc/utilities/Documents/DSP-Webinar8-PUC-Presentation.pdf

Presentation – Tricia DeBleeckere – https://www.oregon.gov/puc/utilities/Documents/DSP-DeBleeckere-Presentation.pdf

**Webinar video**

A recording of the session can be viewed at the following link:

https://oregonpuc.granicus.com/MediaPlayer.php?view_id=2&clip_id=540

**Stakeholder questions**

*Please note that questions and answers may have been edited for clarity and brevity.*

1. During the process for setting the distribution plan requirements (slide 8), who were the main stakeholders that commented or were involved in the process? Did the PUC reach out to other groups not typically represented in PUC proceedings to get their input? For example, were small businesses represented in the process?

   Minnesota has a long history with stakeholder engagement. The PUC reached out to stakeholders in related dockets and started with a broad scope. Community-based organizations were already involved and participating in dockets.

2. John Shenot started his presentation by noting the importance of customer value. How is that assessed in the Minnesota process? And alongside the previous question, have efforts been made to bring in community based organizations into the process?

   One of the guiding principles is customer value, which comes as ensuring that DERs on the system have customer value. The process is so new, however, so we are still working out the logistics of explicitly considering customer value.

   Community-based organizations have a history of participating in Minnesota's processes so we don't necessarily have to go get them to participate.

3. To what degree has the Minnesota process addressed data issues -- access, ownership, security/protection, privacy, etc.?

   There are many ongoing dockets related to these issues but more work needs to be done. There is a customer privacy docket, and the Commission has ruled to some degree on the issue. But as we increase penetration of AMI and hosting capacity, it's absolutely becoming more of an issue. Without pressure from the Commission to further the issues, they will end up at a stalemate.

4. If you look at what has happened with a lot of AMI in CA at least there was the promise of improved services and in reality getting that AMI data has been a real hassle. I say this as someone who oversaw a third party authorized data recipient from both SCE and PG&E.

   Minnesota is watching the PG&E data issues and issues related to feeder-level data. The difference in what utility across the nation is comfortable providing varies widely.

5. Does Minnesota have intervenor funding for those community-based stakeholders that you mentioned are participants in PUC proceedings?

   The Public Utilities Commission does not have intervenor funding but community-based organizations are funded to participate through philanthropic initiatives.

6. In Minnesota is there a requirement that the utilities follow the non-wires analysis with a procurement process for non-wires solutions?

   There is not a procurement process for non-wires solutions. It may be a longer-term distribution system planning target.

7. How frequently does Xcel update its hosting capacity analysis?

   They are required by statute to submit one every two years, but they voluntarily submit it annually. Stakeholders find this to be inadequate, however.

8. How do the investor-owned utilities in Minnesota categorize data expenditures? Are they capital? O&M? And if they're O&M, what's the incentive for the utility to invest in critical needs like data cleanup and management?

   It depends on how the utility crafts a package for approval and investment. Data has been categorized as a capital expense, but historically it may have also been categorized as O&M.

   We saw with an ADMS investment in the state - the utility started implementing the ADMS but then also saw that the GIS was inadequate and to update the GIS data was a huge expense on the order of millions of dollars
   .

9. Is the long-term modernization and infrastructure plan a standalone document or is it part of a General Rate Case or some other filing?

   It is a subset of the Distribution System Plan, which should align with rate case investments or projections. We've seen value in being able to align rate case requests with distribution system planning.

10. How are major rate cases, resource plans, EV plans, and distribution system plans currently sequenced?

    It currently falls as it may. There are also many other plans (e.g., transmission planning). Stakeholders have called out the need to align the multi-year rate case, resource plans, distribution system plans, and the performance incentive metrics docket. The dockets are so interrelated that it's hard to do them separately, but it is also hard to do them together.

11. In understanding Minnesota's iterative approach to distribution system planning, are there one or two things to emphasize for Oregon in consideration of their own process?

    Leverage use cases to plan towards specific objectives.

    Be clear about the end goals that you are navigating towards and continue to come back to that document, recognize it might change over time.

12. Is there a specific document we can look at that lists the MPUC's current DSP requirements?

    Xcel's 2018 Integrated Distribution Plan filing requirements are on page 6 in the following: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7bF05A8C65-0000-CA19-880C-C130791904B2%7d&documentTitle=20188-146119-01

13. Reflecting on the comment that some utilities had to add capacity to complete distribution system planning, was that a common trend? Did the Commission also need to add staff to work through this?

    Utilities were ramping up staff to address DERs. They have all been trying to maintain or increase their staffing.

The Commission and Department don't have funding to add staff.  One person was added, but she's been maxed out since starting.  More staff would be needed to adequately address issues.

14. Has concern about resilience in the face of threats like flooding, tornados etc. impacted distribution system planning?

    Storm years have factored into planning to harden the grid.  The Commission also understands this is an expense that is coming.  The planning effort helps to explain the need before the funding request comes in.

15. Have you all considered third party evaluation of NWAs given that there is an inherent conflict of interest when the outcome of NWA assessment directly impacts the utilities' returns?  It seems problematic to have a utility running a procurement to alleviate a need and also bidding on it (effectively, with wires solutions in this case) at the same time.

    Minnesota is not yet allowing third party bidding.  Independent evaluations are used for large energy procurements, but we aren't doing that for non-wires alternatives assessments.  This may be more of an issue as we close the cost disparity gap.

16. How do you evaluate prudence in distribution system spending?

    Distribution system planning doesn't have a requirement of prudence.  The planning step is to preview incoming funding requests.  Once the funding request is made, then prudence will be assessed.

    (from the audience) One way to evaluate prudence would be to look at improvements in reliability by changes in SAIDI or SAIFI.

## Webinar #9 – Oregon Policies and Practices

**Presented by Oregon Public Utility Commission Staff**

**Wednesday, June 10 from 1:30-3:00 pm Pacific**

**Presentation abstract**

The session will consist of an overview of the Oregon Public Utility Commission policies and practices likely related to Distribution System Planning including: Interconnection Transparency and Planning, and the Smart Grid Report.

**Speaker bio(s)**

Caroline Moore and Eric Shierman serve as Staff in the Energy Resources and Planning Division of the Utility Program.

**Presentation slides** can be found at the following link: https://www.oregon.gov/puc/utilities/Documents/DSP-Webinar9-PUC-Presentation.pdf

**Webinar video**

A recording of the session can be viewed at the following link:

https://oregonpuc.granicus.com/MediaPlayer.php?view_id=2&clip_id=557

**Stakeholder questions**

*Please note that questions and answers may have been edited for clarity and brevity.*

Distribution System Planning Overview

1. Comment (not question): I read the GridLab paper cited here. This diagram is useful as a base or as "one lens," but because the paper contained a significant chunk on stakeholder engagement, I am surprised that isn't included in this diagram.

   Noted for OPUC consideration in UM2005.

2. Comment (not question): The graphic that outlines the process of planning (from Gridlabs) is such a highly simplified view of the process when in reality the better metaphor is either a universe or a weave and as such moving one thread changes the smoothness or efficacy of the weave.

Interconnection Transparency and Planning

3. As one of PGE's larger energy customers (City of Portland, Fleet & Facilities), we are generally concerned about the common approach to paying for interconnection costs for some of the infrastructure upgrades we will need to do things like green our fleet and encourage beneficial electrification in our facilities - large loads, distributed

throughout the system. Primarily, having to bear the "first mover" costs of innovation is disconcerting. I don't have a solution but overall I'd like to have the commission think about how socially beneficial initiatives that support decarbonization can be made cost-effective for customers, particularly those who have either a desire or a mandate to move fast and thus are seeding the infrastructure upgrades for the general public.

Residential solar customers feel the same as expressed above, when they're asked to pay for something that would benefit many (upgrading a substation).

CUB has also raised the issue of cost allocation before and would like to see it addressed in DSP.

Noted for OPUC consideration in UM2005.

This is an interesting and emerging question on generators and users which also applies in other contexts (e.g., electric vehicles). We need to think about how generators and users work together in the system. As part of interconnection, an emerging issue is better understanding what is a reasonable cost for a generator to pay.

(from the audience) PGE is doing a lot of work with CUB and Staff, as well as other interested stakeholders, on Transportation Electrification and a mechanism to justify up front capital investments where managed charging would improve grid outcomes/reduce long run costs. We look forward to continuing to support beneficial electrification, and dialogue around appropriate means to efficiently integrate these new resources for the benefit of all customers.

4. Are there specific utility studies you are referring to here?

   Each individual interconnection request receives some kind of engineering study from the utility to identify system impacts and associated upgrades.

5. One additional consideration is what are the assumptions in the load forecast - are you including DER forecasts? There are implications for utilities making grid investments to accommodate these ahead of interconnection.

   Noted for OPUC consideration in UM2005.

6. In Pacific Power territory, we've run into challenges with system impact studies for small (50kW-1MW) projects that include upgrade costs well beyond what a project can pay with very little detail to critically evaluate those costs or determine what additional capacity benefit might result from those upgrades. How can project proponents or third party consultants vet those costs? When considering multiple projects in a small area, how might we determine where to best apply funds for interconnection system upgrades that could potentially benefit more than one project?

   Noted for OPUC consideration in UM2005.

7. A focus on data issues broadly speaking should be a key part of the next round of the docket, this is a complex and cross-cutting concern

Noted for OPUC consideration in UM2005.

8. How will you quantify and incorporate projects/upgrades that benefit historically marginalized neighborhoods, and what do you need from advocates to help you weigh those impacts? Fair pricing/rates/costs to customers is important, with disaggregated customer profiles.

   Noted for OPUC consideration in UM2005.

   Audience Input:
   a. I would say that one potential example is working with county health officials to monetize a potential non-energy benefit / shared investment stream to install batteries at customer's homes with oxygen machines or other sensitive medical equipment.
   b. Utilities could offer medical baseline rates that would allow customers to purchase this service from a competitive market. Or compensated for the medical baseline rate but not for ownership of the asset - to be clear
   c. I think we can start talking about how to better serve frontline communities by no longer requiring cost effectiveness for low-income programs
   d. Lots of non-energy benefits can come from community-scale energy projects that should be accounted for somehow, such as irrigation upgrade budgets that put water back in stream for small scale hydro or just generally keeping energy monies circulating in local communities.

9. How do we give these communities the information they need to affordably build all electric housing and using new energy technologies to REDUCE overall load and not just increase it - like EVs which get a lot of utility interest because they increase loads.

   (from the audience) There isn't a short answer to that question. And we shouldn't only be looking at building new. How do we retrofit existing housing too?

   Noted for OPUC consideration in UM2005.

<u>Smart Grid Reports</u>

Questions from staff - What smart grid report elements should carry over to the DSP?

- The technical detail in the smart grid reports is helpful and should be incorporated into DSP in some fashion, whether the smart grid reports continue as formal submissions or not
- There are parts of the smart grid report which are only relevant to the bulk power system/transmission and are in that sense not directly relevant, but operationally and within DSP it is important to consider all smart grid capability across the system
- Would the DSP report take the place of the Smart Grid report? Essentially, removing the requirement to submit a Smart Grid Report?
- PGE feels there is a lot of overlap in the safety, reliability, and resilience metrics reported in the Smart Grid report that we feel carry over to DSP. In earlier workshops under UM2005, PGE stated our core values are the

safe, reliable provision of electricity through the distribution system, and therefore see these features as natural components to roll over, among potentially others

Questions from staff - What should be added to DSP that was not in the smart grid reports?

- Need to focus on data issues as part of the next round of the docket. With data concerns, there are tradeoffs between security and accessibility – DSP needs to consider customer value
  - We need also to be careful though that security doesn't become a smokescreen for hoarding data. There are plenty of data security protocols that could allow for more democratization of data. Here's a great example: https://data.svcleanenergy.org/.
- DSP should address cost allocation …this was not a part of the Smart Grid report. DSP should include principles similar to IRP, for example, least-cost, least-risk
- Is there enough information regarding specifically small nonresidential customers and the value of smart grid reports and DSP?

Questions from staff - Why do we value non-wired solutions?

- Is there actually a related question: HOW do you value non-wired solutions? They're primarily pertinent if they have some kind of cost/benefit relationship to wired solutions.
- Non-wire solutions can provide a stack of benefits including deferral of investments in distribution upgrades as well as possibly providing local resource adequacy.

Questions from staff - Besides wired solutions, what other costs might distribution planning avoid?

- As mentioned it could avoid excessive O&M and program costs per the last comment
- It would provide greater visibility to the Commission staff about the need or lack of utility investments which would be useful in General Rate Cases
- Better distribution system planning and resulting capabilities -should- help create significant load management that will avoid fuel cost for existing resources and new generation and transmission capital and O&M
- DSP could be used to flatten residential system peaks. Everyone benefits from better load factor
- From a customer standpoint, it could help me identify where/how to connect large loads affordably
- When tied with Homeland security/FEMA islanded communities reporting to be published in the Fall DSP could complement additional values of prioritizing for resilience investments.

## Webinar #10 – Oregon Policies and Practices & Next Steps

**Presented by Oregon Public Utilities Commission Staff**

**Thursday, June 11 from 1:30-3:00 pm Pacific**

**Presentation abstract**

The session will consist of an overview of the Oregon Public Utility Commission policies and practices likely related to Distribution System Planning including: Integrated Resource Planning, the Transportation Electrification Plan, and the Public Purpose Charge, as well as the expected next steps in the investigation.

**Speaker bio(s)**

Rose Anderson, Eric Shierman, and Anna Kim serve as Staff in the Energy Resources and Planning Division of the Utility Program.

**Presentation slides** can be found at the following link: https://www.oregon.gov/puc/utilities/Documents/DSP-Webinar10-PUC-Presentation.pdf

**Webinar video**

A recording of the session can be viewed at the following link:

https://oregonpuc.granicus.com/MediaPlayer.php?view_id=2&clip_id=559

**Stakeholder questions**

*Please note that questions and answers may have been edited for clarity and brevity.*

Integrated Resource Planning

- How each individual input and output should be coordinated across IRP and DSP should be discussed by stakeholders
- Agree with presentation; points about DSP and integration into IRP is really important and one that Pacific Power is also thinking about; will likely have questions as we move forward
- Could someone repeat how often IRPs are filed, and how often TE plans are filed (and clarify that the current thought is DSPs will be filed approximately every year)?

  IRPs and TE Plans are filed bi-annually (every two years). Timing of DSPs has not yet been determined.

Transportation Electrification Plans

Questions from staff - Which Transportation Electrification Plan elements should inform distribution system planning?

- Transportation electrification should be closely linked to distribution planning. New load may best be accommodate through additions of new DERs rather than centralized generation and T&D expansion.
- Charging load profiles, EV adoption rates
- The general consensus seems to be that the future of the grid is more of an interconnected web with multidirectional energy flows rather than a spoke and hub model of the past. With the assumption that this new grid model comes to fruition, would this not naturally suggest that starting at the grid edge and working backwards makes the most sense? The opportunity for communities to more actively participate would be maximized by employing the bottoms-up approach, giving them an opportunity to help shape the vision of the grid at their part of the distribution system. By having competitive RFPs like the IRP as part of the DSP - the ability to meet the changing grid edge through innovation and additional grid edge solutions is enabled.
- Can Staff clarify if a DSP plan includes all components of the TE plan requirements, would utilities still be required to submit a TE plan?

  This has not yet been decided, though it could be reasonable if the entire plan is within the scope of DSP.
- Mix of charging types (Level I, II, fast charging), mix of single family, multi-family residential, various types of commercial, street level etc. charging locations, TOU rate choice by EV users, projected EV adoption rates including passenger/light and heavy truck/bus, locational strategy for EVSE buildout (for feeder-specific impact analysis)
- Is the idea that the utility owns the TE planning function as part of DSP and then procures the infrastructure and operation via an RFP process?

  We haven't gotten that specific.
- US Dept. of Homeland Security: Oregon cybersecurity and infrastructure security agency (CISA) Transportation Regional Resiliency Assessment Program (RRAP) will release a map of Oregon defining where communities will likely be physically islanded for long periods of time. As electrification of the transportation sector develops, and in the interests of public safety, DSP could include the resilience values of DG to provide for the TE loads within each island. Whatever informational overlap is required to accommodate that analysis should be integrated into DSP.

Questions from staff - What other stakeholder interests would a general power flow study help to inform?

- I would think that the small nonresidential class of ratepayers could be very helpful. What I mean is that if small nonresidential ratepayers are concentrated in areas such as larger concentrations or cluster in urban settings, or in commercial centers like strip malls, in the day when load is greatest, this is an opportunity to include this power flow planning.
- Not sure if this is what you're looking for. But this might be useful to hosting capacity and constraints. For example, if a given feeder is full and can't take any more solar, increases in EV deployment on that feeder might have an impact.
- Is there going to be a contract/guarantee for the resources accounted for in the power flow?

Questions from staff - Is power flow modeling in DSP an analogue to capacity expansion modeling in IRP?

- The NW Power Council has begun looking at system level modeling of complementary assets to extend the carrying capacity of each. John Ellis and John Fazio are working on this with regards to Hydro/Solar/Wind and other system level interactions - essentially improving the load carrying capacity of each at the system level

  Here is more about the NWPPC's ASCC which looks at the portfolio of resources (i.e. interaction of PV and EV was mentioned) rather than each asset individually.
  https://nwcouncil.app.box.com/s/wjwtvv2xbju46fzkjaiurha6sb3l5ijm
- EV infrastructure - especially commercial scale EVSE that would be required for municipal fleets and mass transit - can run into constraints on the grid. This is the reverse challenge of renewable energy interconnection constraints being found on the grid currently. Would EV hosting capacity analysis be different than the hosting capacity analysis described previously to improve interconnection processes?
- I would add that a difference in terms of this analogy is IRP LOLP modeling looks at expected loss of load hours from Monte Carlo modeling (at least how PGE does it) and then evaluates contributions of iterative supply resource additions to reduce expected loss of load hours to at or below the benchmark 1-in-10 year outage requirements. So for Power Flow relationship to DSP, we could say Power Flow could inform some such modeling. Currently, these types of analyses are very different in practice and scope

    (Clarifying the point above) Capacity expansion modeling seeks to optimize resource additions, whereas power flow modeling gives you more of a sense of how the system operates given a set of loads and resources. A better analogy within IRP might be production cost modeling, but there are still important differences.

Public Purpose Charge

- Under which category do DSP investments qualify to use PPC funds? From the slides, it looks like OPUC is proposing using PPC for DSP

  Not suggesting changes to the ultimate goals of the buckets. The primary goal, and ongoing goal, is the cost-effective acquisition of EE. But with collaboration on DSP, we might be able to identify where to focus attention sooner for the benefit of the customer

- NWEC really supports the PPC; we've spent a lot of time thinking about how to set it up and launching the Energy Trust. There is a clear role and guidelines around what it is supposed to do. Using PPC to support DSP seems to work against the intention to have a focused amount of money for procuring resources. There may be a way to shape those funds in a way that is beneficial to DSP, but would want to talk more about whether/how allocating PPC to fund planning

  Don't want to suggest that PPC funding would be reduced. This is more about being a partner where it makes sense, not about reallocating funding away from EE

    It's worth having a dialogue about this. A locational approach to EE spending and renewables will have an impact on the distribution system, are interesting things to talk about. Still perplexed about where this discussion should go

Are there things outside of the program implementation portion of ETO that should be addressed? How would the link to DSP go beyond what they are able to do today?

Not thinking for ETO to go beyond what they are doing today. Not so much about taking away from DR, but partnering on DR. Set up to do locational value once it's available

- Is there a role to think about how granular ETO forecasting is/should be in a DSP context?

- I think that using funds to provide more flexibility for low-income programs so we would not be tied to cost-effective measures is a worthy use. In Portland, PCEF provides a potential source of income that could co-fund new projects.

- Perhaps the question should be "How can we best use public purpose funds to inform (not support) distribution system planning?"

- Possible use case for EE/DSP: HPWH – could be an EE measure that also has a flex DR component, both of which have implications for the distribution system – could HPWH then become a non-wires solution

  We are doing a Heat-Pump Water Heater replacement program now with ETO funds for Low-Income customers, and are getting co-funding from Nike and looking for PCEF in the future.

  Distributed Energy Resources (DERs) like energy efficiency, solar+smart inverters, or solar+storage have the ability to provide both their core benefits of energy efficiency and renewable generation AND they can also provide other grid services like demand response, frequency/voltage regulation etc. Earlier comment beat me to it!

  The resource at the end provides a flexibility value to the grid. They can all be used to help balance the sources and sinks in a way that benefits the grid

- I think the "better coordination" Staff mentioned is the goal, and would be possible with greater data/process transparency implicated by DSP. Ergo maybe the processes good DSP create, are used to inform the long-term use of the PPC.

  I agree. As we seek more circuit-level understanding of load and resources as part of DSP, well-coordinated sharing of information about building types, equipment and end-use types, etc. would promote robust modeling

- This is the time to bring in the CBO's to talk about how we could creatively be more involved with real on the ground experiences and ideas.

  Many support this comment and want to have more discussion on how to incorporate customers and community. Really need to elaborate more on the themes heard from CBOs

- As one last comment wrapping up what everyone was saying about public purpose charges: DOE's GEB is looking at the interactions between grid-interactive efficient buildings and communities and how the whole is greater than the sum of its parts when it comes to distribution value. We need a transparent model for the portfolio of assets that can contribute to meeting system capacity requirements, rather than first modeling system capacity and then independently modeling resources.

DOE is looking at how to combine programs funded with the public purpose charge (e.g., EE, DR) and how that combines with DERs within the context of communities.  In communities, they've modeled a portfolio of smart BTM assets and studied how to look at those resources in sum, and how they meet system requirements.

It is very important that the modeling looks at capacity and identifies the needs (i.e., well-articulates the types of needs for the system) and then allows for a longer procurement timeline to open up the procurement to community offerings and modeling.

Under the current paradigm (e.g., in smart grid, TE plan), everything is handled separately - there are lots of separate tariffs that do not work well together.  Operating programs separately with individual incentives does not get to cost-effective results.

## Workshop #4 – Draft DSP Guidelines

**Presented by Oregon Public Utilities Commission Staff**

**Wednesday, October 21 from 1:00-3:30 pm Pacific**

**Workshop abstract**

Staff held Workshop #4 to discuss the Draft Guidelines for Distribution System Planning (Draft Guidelines) released October 1, 2020. The Workshop goals included:

1. Shared understanding of scope and intent of Draft Guidelines.

2. Opportunity for parties to receive clarification on questions regarding the Draft Guidelines.

3. Opportunity for parties who do not plan to file written comments on the Draft Guidelines to provide feedback.

4. Opportunity for parties generally to provide feedback.

5. Shared understanding of Staff's planned approach to addressing stakeholder feedback on Distribution System Planning Guidelines over time.

**Presentation slides** can be found at the following link:
https://edocs.puc.state.or.us/efdocs/HAH/um2005hah122044.pdf

**Webinar video**

A recording of the session can be viewed at the following link:

https://oregonpuc.granicus.com/MediaPlayer.php?view_id=2&clip_id=656