UM 2005 Technical Work Group
May 26, 2021 Notes and Questions

June 7, 2021

Below are notes from the May 26, 2021, Technical Work Group meeting, as well as revisions to questions discussed during the meeting (revisions were made with track changes).

Attendees:

- PUC Staff:
  - Nick Sayen
  - Garrett Martin
- OSSIA: Angela Crowley Koch
- Idaho Power
  - Mark Patterson
  - Kelly Noe
  - Jim Burdick
  - Chris Cockrell
- CUB: Sudeshna Pal
- Energy Trust: Spencer Moersfelder
- Renewable NW: Micha Ramsey
- PacifiCorp
  - Erik Anderson
  - Teri Ikeda
  - Wyatt Pierce
  - Robyn Kara
  - Jonathan Connelly
  - Heide Caswell
- PGE
  - Angela Long
  - Nihit Shah
  - Derrick Harris
  - Joe Boyles
  - Bachir Salpagarov
  - Tony Grentz
  - Joe Boyles
  - Misty Gao
  - Shadia Duery
  - Stefan Brown
- NWEC: Fred Heutte
- TeMix: Stephen McDonald
- Oregon DOJ: Natascha Smith

Questions/clarifications/etc. on follow up materials from the April 21, 2021, meeting

There were no questions or clarifications on the follow up materials from the April 21, 2021, meeting.

Section One - Unresolved questions from the April 21, 2021, meeting

Please note that new content, and revised content, has been added in this section using track changes to distinguish between content circulated *ahead* of the May 26 meeting, and follow up *from* the May 26 meeting.

<u>Long Term Plan Questions</u>

1. Can staff provide additional context and detail on the requirements 4.4.b.i.2 and 4.4.b.i.3:

i. *"Assessment of investment options to enhance the grid across the following range of areas, including relative costs and benefits:*

.....

2) Distributed resource and renewable resource enhancements

a) Penetration and activation/utilization of smart inverters

3) Transportation Electrification enhancements"

Response: The requirement states that one part of the utility's long-term DSP vision should include assessment of potential investment options to enhance the grid, and these options should include potential investments to enhance for DERs. Penetration and activation/utilization of smart inverters is an example of DER enhancements, and not the only possible enhancement.

The potential investment options should also include investments to enhance for transportation electrification (TE). Including an assessment of TE investments does not replace, or make redundant, the Transportation Electrification Plan; instead, including an assessment of TE investments in 4.4.b.1 only requires utilities to include TE (among other investment options noted in 4.4.b.i) in the thinking done to develop the Roadmap of planned investments, tools, and activities. Assessments for 4.4.b.i should include relative costs and benefits.

Discussion in April 21 meeting: Staff noted this question addresses content from the Smart Grid Report that was rolled into the Guidelines. This question, and Staff's draft response, will be discussed further as time ran short this meeting.

Discussion in May 26 meeting: Staff provided context for requirements 4.4.b.i.2 and 3. In general, section i was pulled from the Smart Grid requirements, including requirement 2. However, requirement 2.a is new (not carried over from the Smart Grid requirements), and is intended as an example of such enhancements, and not the only possible enhancement. Requirement 3 is also new (not carried over from the Smart Grid requirements). Though there is overlap with this requirement and the Transportation Electrification Plan (TE Plan), it is not meant to replace or be redundant to the TE Plan. Instead, the requirement asks utilities to include transportation electrification (among many other factors and investment options included in 4.4.b.i) in the thinking done to develop the Roadmap of planned investments, tools, and activities. A high-level, strategic summary of transportation electrification's place in the Roadmap would be responsive to requirement 3.

Part 2 Questions

2. Per requirement 4.5.a:
   "How legacy distribution planning practices will be transitioned to the requirements of Part 2"
   Can staff confirm the specific aspects of planning practices they are referencing in Part

2? For example, are DER forecasting, and non-wire alternatives analysis the two aspects of planning that are required for Part 2?

Response: "Legacy distribution planning practices" is a general reference to the activities which comprise utility distribution planning prior to Order No. 20-485 (referred to here as "status quo activities").

Part 2 articulates a process with four major components, organized in a linear fashion (Forecasting of Load Growth, DER Adoption, and EV Adoption; Grid Needs Identification; Solution Identification; Near-Term Action Plan). However, status quo activities as implemented day-to-day may not line up with the four components of Part 2.

Requirement 4.5 states utilities should plan for how day-to-day implementation of status quo activities transitions to day-to-day implementation of the four components of Part 2, and share a high-level summary of that transition. The requirement asks for a forecast of the Part 2 filing; it is an opportunity to provide a preview of the process in Part 2. Requirement 4.5 does not ask for the results of the analysis, or a forecast of the results of the analysis, that might be conducted for Part 2 (for example, grid needs).

Discussion in April 21 meeting: Staff noted that requirement 4.5 is for a high-level summary, and that this question, and Staff's draft response, will be discussed further as time ran short this meeting.

Discussion in May 26 meeting: Staff noted the response provided for the April 21 meeting:

- "Legacy distribution planning practices" is a general reference to the activities which comprise utility distribution planning prior to Order No. 20-485 and are discussed here as "status quo activities".
- Part 2 articulates a hypothetical process with four major components in a linear fashion (Forecasting of Load Growth, DER Adoption, and EV Adoption; Grid Needs Identification; Solution Identification; Near-Term Action Plan).
- However, status quo activities as implemented day-to-day may not line up with that hypothetical, linear process.

Requirement 4.5 states utilities should prepare for how day-to-day implementation of status quo activities transitions to day-to-day implementation of the four components of Part 2, and share a high-level summary of that transition.

Staff noted an example discussed during the May 24 Pacific Power DSP meeting: as a status quo activity, Pacific Power conducts area studies with varying frequency, some every five years, some more often. Presuming for the sake of this example that conducting the area studies is a core part of Pacific Power distribution planning, then the Company would thus include it in responding to Requirement 4.5, and summarize how the process for conducting area studies might evolve for Part 2. For example, the status quo practice may change, and the entire service territory may get a fresh area study for August 2022. Or, alternatively, the status quo practice may not change, and the current process moves forward as-is.

Requirement 4.5 asks for a forecast of the Part 2 filing; it is an opportunity to provide a high-level preview of process for Part 2 for stakeholders, to avoid surprises in Part 2, and to start any discussions earlier rather than later. Requirement 4.5 does not ask for the results of the analysis, or a forecast of the results of the analysis, to be conducted for Part 2 (for example, grid needs).

Review and discussion of May 7 Data Transparency Workshop

The meeting moved into a discussion of the May 7 Data Transparency Workshop (this was out of order from the agenda). Staff acknowledged that the Workshop was somewhat of a novel approach, and again expressed appreciation for stakeholder participation and engagement.

Staff will follow up with notes from the Workshop, as well as an updated version of the spreadsheet which will include both input from the workshop itself, as well as Staff's content prepared ahead of the Workshop. How to provide the updated spreadsheet will require some additional thought and creativity as the file is currently in .xlsx format.

Staff asked for reaction and follow up to the Workshop, and Technical Work Group participants shared the following:

- The suggestion to establish common definitions of data types (and common acronyms) would be an important/useful step.
- How can "parking lot" questions be addressed moving forward?
- Where and how data will be stored is an important question to discuss early so there is a way to manage, keep safe, and access data as it comes in.
- Is some of the data in question the same as the data discussed in AR 564?
  - Neither Staff nor DOJ was sufficiently familiar with AR 564 to respond to this during the meeting; Staff will follow up.
  - **Staff follow up:**
    - In AR 564 the Commission issued Order No. 12-323, wherein the Commission adopted rules governing the sharing of customer information between energy utilities and the public purpose fund administrator, at the time the Energy Trust of Oregon.[1]

[1] This resulted in Permanent Administrative Rules PUC 6-2012. Rule summary:
These new rules and rule changes facilitate the sharing of customer information between energy utilities and the public purpose fund administrator designated under ORS 757.612(3)—currently the Energy Trust of Oregon. The rules are designed to allow the Energy Trust to more efficiently and comprehensively acquire energy efficiency and promote renewable energy development. First, the rules supersede existing information sharing provisions found

- And so, as customer data was addressed during the May 7 workshop as two of the 21 data types examined (individual data and aggregate data) AR 564 does address some of the same data. However, AR 564 addresses only a narrow set of arrangements regarding customer data.

- Discussion ensued on the following important aspects of customer data: 1) granularity; 2) specificity; 3) temporal accuracy; 4) temporal consolidation; and 5) comprehensiveness, as well as how other jurisdictions address customer data.
  - Examples of how other jurisdictions address customer data were welcomed.

Staff asked whether participants believed that continuing to work on the spreadsheet – around which the May 7 workshop was oriented – with a goal of a complete and current version for Oregon seems like a valuable pursuit.

Participants responded that the spreadsheet seemed useful, but also noted that it would be helpful to see the post-workshop updated spreadsheet to consider and answer that question.

Staff proposed to address this question again in a future TWG meeting once Workshop wrap up was complete.

Section Two – New questions for discussion and consideration

3. To ensure options analysis is considering the needs of stakeholders, can stakeholders describe the expected use cases for a hosting capacity analysis including the granularity of data beyond the DER readiness map?

   Discussion topics included:
   - The value and cost of real-time data, various associated protocols, and whether utility AMI systems included HANs (PGE/PAC/IPC - they do not) and/or FANs (PGE/PAC - they do; IPC noted their AMI system uses a different communication technology).
   - The California Public Utility Commission Staff recently held a workshop on advanced distributed energy resources and flexible load management which included, amongst other topics, discussion of real-time data, pricing, and the transactive market benefit.
     - **Stakeholder follow up:** Presentations and recording of the workshop can be found here.
   - Some utility systems do not currently have SCADA connectivity; the decisions about SCADA upgrades are made with economic costs and benefits in mind.

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in Division 038 (Direct Access) that apply only to electric utilities and create a new Division 086 (Customer Information) that also covers natural gas utilities. Second, the rules significantly increase the amount of confidential customer specific data the Energy Trust receives from electric and natural gas utilities. Third, the rules expressly permit the Energy Trust to use the information to conduct direct marketing using the utilities' customer contact and usage data. Fourth, the rules require the Energy Trust to provide more information to the utilities about their customers' participation in Energy Trust programs.

- Customers asking the question ‘W*here should my solar system go?’* are not able to answer that question through the DER readiness map; instead hosting capacity analysis is needed to answer such questions. Community solar interconnection struggles illustrate the challenges small organizations encounter with interconnection.
- Examples of typical interconnecting projects may be useful in illustrating expected use cases. The typical project types discussed include 1) a qualifying facility (QF) project, 2) a community solar program (CSP) project, 3) a commercial net-metering project, 4) a residential net-metering project. Staff asked participants from the Energy Trust of Oregon, whether Energy Trust may be able to provide data on typical projects for some of these 4 project types, and the answer was likely yes, pending additional discussion. Staff will follow up on this point after the meeting.

In addition to question 3, PGE also presented feedback the Company received during the ‘Sprint 1’ round of review of the Company’s proposed improvements to the DER Readiness Map.

- The discussion began with a quick recap of the overall status of this effort:
  - The Company received about 60 points of feedback in Sprint 1, which was very helpful and informative; the Company was able to address about 30 of these points.
  - Follow up on Sprint 1 was emailed to contributors on May 24, 2021.
- In reviewing the feedback, PGE also presented several outstanding questions for TWG discussion. These are included in below.
- Finally, there was a question about the basis for using 500 ft. as the size of the buffer zone to protect the system's network model (a Critical Energy Infrastructure (CEI) requirement): is 500 ft. a federal standard/guideline, an industry best practice, a Company specific policy, or something else? PGE staff understood it to be an industry best practice, though noted it may merit additional discussion.

Detailed Description	**Response**
28. Would be helpful to indicate whether the feeder has 3v0 sensing, 59 N, or other things that seem to determine interconnection viability. Similar to indicating whether there is SCADA.	Topic for discussion with TWG: There is a broad range of equipment that contributes to DER Readiness. Adding all of that equipment to the map is unlikely to help customers assess DER Readiness or provide clarity. PGE will work on rolling up all of the data that contributes to DER Readiness so that we can provide a simplified "DER Ready" designation for feeders, substations and transformers.
29. Would be helpful to indicate whether a generator has executed an interconnection agreement the commits them to pay for 3v0 sensing, 59 N, or other things that seem to determine interconnection viability.	Topic for discussion with TWG: We can investigate whether or not the available data support adding some designation that indicates whether or not upgrades are being paid for. However, the dropout rate for QF applications introduces uncertainty. It may not be helpful to base decisions on the actions of higher queued projects.

30. Would be helpful to indicate tier 2 interconnection failures (would say level 1 and 2 net metering too, but not sure that matters for PGE given 2-meter solution) Super low priority but maybe one day include avg. IX upgrade per MW over past 12 months or something...	Topic for discussion with TWG: This is an interesting idea. We would like to explore this use case with the group.
39. Is PGE willing to show locations of reclosers on the feeders? Or number of reclosers on a feeder? It seems the presence of reclosers can drive the need to install additional protection equipment.	Topic for discussion with TWG (see #28): There is a broad range of equipment that contributes to DER Readiness. Adding all of that equipment to the map is unlikely to help customers assess DER Readiness or provide clarity. PGE will work on rolling up all of the data that contributes to DER Readiness so that we can provide a simplified "DER Ready" designation for feeders, substations and transformers.
42. Please add more explanation of how PGE determines which feeders are "generation-limited". It seems like it should be tied to generation:min consumption ratio, but it doesn't appear to be.	Topic for discussion with TWG: A feeder is designated as "Generation Limited" when the ratio of total generation (active + future) to actual load (Net DML + active gen) is greater than 90% (DML = Daytime Minimum Load). In some instances, it isn't the feeder that is at risk. The transformer to which that feeder is connected is at risk. There are instances where two or more "not limited" feeders are connected to a single transformer, pushing the generation:load ratio over 90% at the transformer. In these cases, we label the feeders attached to the transformer as "Generation Limited".
47. In the guide, it says that the DML cannot be less than 0 because of feedback, yet in the pop-up there are feeders with a DML < 0. This is an inconsistency.	Topic for discussion with TWG (see #27): When a feeder and related substation equipment has adequate protection, the Net DML can be negative, i.e., the feeder is able to backfeed onto the transmission system. In these instances, Gen:Load ratio also will be greater than 90%, often greater than 100%.
51. It's unclear how a user can use the pop-up menu to determine how much capacity the feeder has on it. For example, the Canby-Butteville feeder is in yellow, .7 DML. But the DER capacity already exceeds the DML (2.238), which must mean that the feeder has enough hosting capacity for the generation to exceed DML. But how would one know how much capacity is available at the feeder for additional DERs?	Topic for discussion with TWG: The DER Capacity Connected is already accounted for in the Net DML calculation. Because the DER Capacity in Queue is 0MW, .7MW are available for additional DERs.
54. All the downtown feeders overlap, making it very confusing as to what the data actually is. For example, canyon - 13120 - it would appear that there is plenty of room on this feeder from the pop-up box, but it's in orange.	Topic for discussion with TWG: Additional layers can be added to differentiate one color from another, e.g., turn on "Green" areas of DML. How many layers is too many layers?
59. In order to determine if a site qualifies for a Level 1 or Level 2 net metering we need to know "the aggregate generation capacity connected to the circuit, including that of the net metering facility, will not exceed 10 percent (15 percent for solar electric generation) of the circuit's total annual peak load [secure.sos.state.or.us]." Can the total annual peak load information be included in the map, in some form so that CBI is not released? Would the aggregate generation capacity be the installed plus the queued generation?	Topic for discussion with TWG: PGE is investigating the possibility of adding Peak Load information (it can be considered Critical Energy Infrastructure info). We would like to explore this use case to see if there is a way to facilitate this analysis without Peak Load.

60. Red color coding is meant to indicate limited availability on a feeder. However, a negative daytime minimum load can also mean that the substation/feeder has the appropriate protection in place to allow two-way flow of electricity. If the substation has been upgraded, would that mean that there is significantly more capacity? What is the new capacity limit if DML no longer applies? If red doesn't mean bad and green doesn't mean good, then use different colors. Example: ESTACADA-ESTACADA 13.	See #47. This is an area where PGE can work to clarify the data, perhaps by adding DER Ready designations for the relevant equipment - feeders, transformers, subs.
61. PGE has described how they make substations DER Ready whenever the substation is due for typical updates. From those conversations, the sense I got was that DER Ready = adequate protection on the feeder or the substation transformer to allow the two-way flow of power. Can PGE indicate which substations/feeders have been updated to be DER Ready?	See #47. This is an area where PGE can work to clarify the data, perhaps by adding DER Ready designations for the relevant equipment - feeders, transformers, subs.
62. DML color coding does not appear to relate to whether the feeder is considered generation limited. Considering the fact that net metered solar is not able to be interconnected on these feeders without paying for substation upgrades or installing a second meter how can some a generation limited feeder also have excess capacity based on the DML? Example: YAMHILL-YAMHILL 13.	See #27 and #47. This is an area where PGE can work to clarify the data, perhaps by adding DER Ready designations for the relevant equipment - feeders, transformers, subs.
67. Community solar developers have identified the fact that knowing whether a project is upstream or downstream of a recloser is important. Apparently, reclosers do not allow the two-way flow of power and therefor it is important to know what the DML is on the section of the feeder that is downstream of the recloser in addition to for the feeder as a whole.	Topic for discussion with TWG: There is a broad range of equipment that contributes to DER Readiness. Adding all of that equipment to the map is unlikely to help customers assess DER Readiness or provide clarity. PGE will work on rolling up all of the data that contributes to DER Readiness so that we can provide a simplified "DER Ready" designation for feeders, substations and transformers.
69. I am able to purchase historical power outage data at the zip code level from a third party that is connected to an API associated with PGE's outage map. Is it possible to get historical power outage information at something more granular like the feeder level? Customers can typically use distance from a substation as a proxy for their vulnerability and the time it would take to get their power turned back on. But having some historical data to show the count, time of year/time of day start, and length of time of outages would be valuable information in helping communities to site critical facilities.	Topic for discussion with TWG: PGE will investigate the possibility of incorporating this data. We would like to explore this use case to understand how that information will be used.
70. Similar to DER Readiness, is there a way to know that a feeder/substation has been hardened to mitigation the risk of future outages? Is it possible to show the location of sectionalizing equipment?	Topic for discussion with TWG: PGE will investigate the possibility of incorporating this data. We would like to explore this use case to under how that information will be used.

Questions or Feedback

Questions and comments can be directed to Nick Sayen via email at nick.sayen@puc.oregon.gov or by telephone at 503-510-4355.