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Summary of October 25 Meeting

The third workshop in the Incorporating updated standards: IEEE 1547-2018 workstream was held on October 25, 2022. The discussion continued with IREC's Decision Matrix, starting with near-term issues. It appears there was consensus reached on several issues, with some requiring additional work. Following the near-term issue discussion, the mid-term issue discussion continued from the prior meeting. The following are highlights of the discussion as recorded by Staff. If you believe anything is missing or in error please reach out to Ted Drennan.

Near-term Issues

As mentioned, the discussion started with the near-term issues.

Consensus Issues
Staff believes there was general agreement on choices for the following issues. While these are labeled as 'consensus issues' parties may have additional concerns.

Staff would appreciate feedback from stakeholders who disagree with Staff's items on the consensus issues list.

Adoption Timeline

For Adoption Timeline the consensus position was for compliance to begin on April 1, 2023, DO 1a, or a later date, dependent on the availability of inverters compliant with the IEEE 1547-2018 requirements. Staff suggested waiting until July 1, 2023 due to current equipment issues. There should be additional information available toward the end of the year which could impact the date selected.

As for when compliance is required, DO 1b, it will be based on the date an application is submitted, with the caveat that the application must be complete. Incomplete, inaccurate applications will be rejected, and if there are changes to requirements in the interim, the customer will need to abide by the rules in place when a complete application is submitted.

Abnormal operating performance category

The consensus choice for the abnormal operating performance category is to use Category III ride through capability for inverter-based generators. Non-inverter based generators mut meet Category I ride through, at a minimum.

Normal operating performance category
For the normal operating performance category requirements for rotating machines to meet, at a minimum, the Category A requirements, and inverter based DERs to meet the more stringent Category B requirements for reactive power was the consensus position.

Alternative performance category
The alternative performance category is used for technologies that cannot meet the requirements for the Abnormal, or Normal Operating Performance. The consensus was to leave the process undefined for handling exceptions at this point.

Voltage trip settings & range, Frequency trip settings & ranges and Frequency droop[1] Settings

For the three operating performance categories listed (DO-5, DO-6, and DO-7) the consensus choice was to align with default settings, with stakeholders offering no competing proposals.

Voltage regulation modes by active power[2]
The voltage regulations by active power consensus decision is to activate volt-watt settings with default 1547 settings.

Interconnection Rule
This will be considered more fully in Screens, Study Methods, and Modern Configurations workstream.

Issues Lacking Consensus

Staff believes there was only one issue in the near-term issues list that did not have consensus decisions. That is voltage regulation modes by reactive power, as discussed below.

Voltage regulation modes by reactive power[3]

At the second workshop there was a robust discussion on voltage regulation modes by reactive power, and likewise in the third workshop. The utilities, in general prefer a more

[1] Per IEEE 1547-2018, this function cannot be disabled.
[2] The voltage support by active power (volt-watt) is deactivated by default – if desired, consider statewide (or similar) default setting for volt-watt.
[3] The voltage support functions by reactive power (constant power factor, volt-var, watt-var, constant var) are mutually exclusive. By default, these functions are deactivated – meaning certified equipment will come out of the box to operate at unity power factor.

individualized approach here, noting that the optimal approach may be dependent on the specific project, including the size and location. However, there is a possibility that there could be preferred settings for small generator projects, which could help in transparency issues. This could be part of the utility required profile (URP) if it is used going forward.

Other questions were raised as to where these requirements should reside. That is, would these requirements be in the OARs, or perhaps in the utility interconnection handbooks. Another suggestion was to look at incorporating the requirements on a feeder-level basis, perhaps leveraging some of the hosting capacity analysis maps.

Staff believes parties were gong to submit more information on this in the near future. It is not clear if consensus on this issue in the workshops is achievable, but it is worth examining any proposals received.

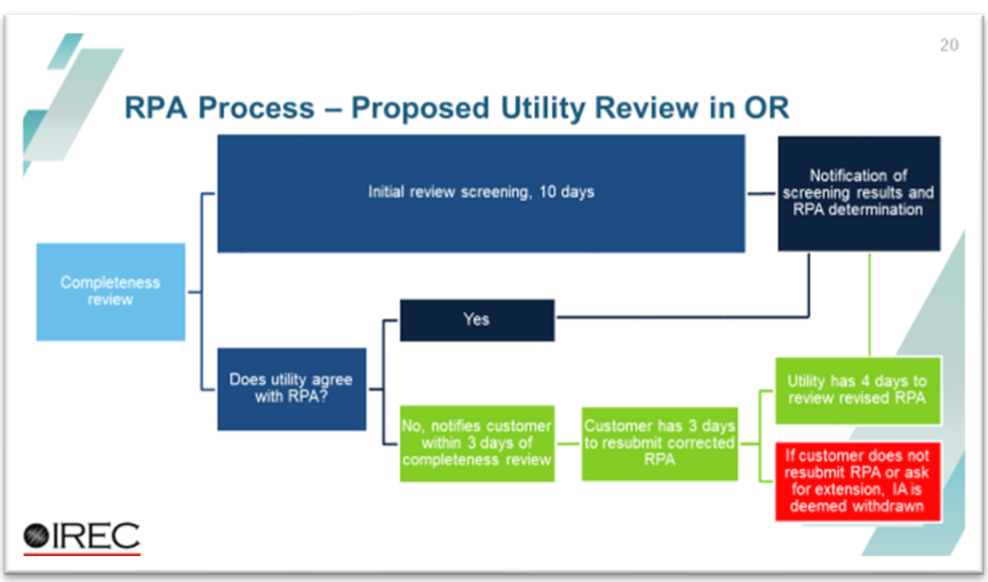
Staff is still interested in stakeholder recommendations, especially those addressing issues related to requirement differences based on resource size, location, composition of loads on feeders, or other factors.

Mid-term Issues

At the September 28 workshop IREC began discussion of mid-term issues which continued at the October 25 workshop.

Reference point of applicability Process

Reference point of applicability (RPA) was discussed at the prior meeting, with questions from stakeholders as to how the process would match with current practices. IREC provided the flow chat that follows in the presentation.



The process envisioned for review of the RPA would run parallel with the other initial screening processes. The figure above has 10-days for initial review screening. The utility would have three days to review the RPAS, if there are issues the customer would have four days to fix, then another three days for utility review.

Utilities were concerned with the current process; with major changes in application processing required to run parallel processes. There was further discussion of the processes currently taken by the utilities. Once an application fails, the customer is notified, and the application put on hold. Once the defective applications are corrected, they are placed at the back of the queue. It wasn't clear to Staff if all defects are noted in the rejection sent to the customer for all utilities.

It was also noted in the discussion that there would be need for training for the contractors and developers upon any substantive rule change. The parties did not want confusion on what data would need to be submitted.

Staff would like more information on the processes used by the utilities when rejecting applications. Are applicants notified of all infirmities in the application, or only the first issue discovered? How are re-submitted applications treated as far as queue position?

<u>Replacement Units</u>

Decisions related to end-of-life or other equipment replacements was the next topic. Here decisions will need to be made on what replacement equipment will be allowed. Any requirements could allow for matching original interconnection requirements or match the then current requirements. The first case would allow for like-for-like replacement -which could include warranty replacement, or customers with spare parts matching the original specifications. Under a current-requirements scenario the customer may need to procure new equipment. At that point the question would be to have the inverter settings match with those in the original interconnection agreement, or match with those in place when the inverter is replaced.

Other questions here involved material modification processes, for instance does reduction of generation count as a material change, or just increases in generation. Also – what would any changes to the material modifications process mean for existing distributed energy resources (DERs). It appears the utilities may have different perspectives on this issue.

Staff would like to know current utility practice on end-of-life equipment replacement for SGIP and NEM customers. Can customers freely change the equipment, or are there utility requirements? There are similar questions for material modifications for the utilities – what is allowed, what processes need to be followed.

Staff is also interested in what stakeholders think the requirements should be for replacements, or material modifications and why.

Interconnection Agreements

There was discussion on the need to update the standard interconnection agreement (IA) to include provisions for the required functional settings and updating settings or equipment over time. Parties believed this could be accomplished via the appendix included with the standard IA, at least in the near term. It was noted there will be a need for many changes depending on what the final rules reflect. For instance, if export limited capacity is used, the forms will need to reflect that.

Staff would like to hear further from stakeholders if they believe the interconnection agreements need to be updated.

Application forms

There was a brief discussion of updating application forms, with several examples from IREC's BATRIES, which could be used as a starting point for updating. One question on the application form asked if the DER is, "designated as emergency, legally required, or critical facility backup power." This question was included, as DERs in these categories do not need to follow all of the IEEE requirements. Parties were not sure if the language was correct in the current situation, believing it may need some modifications. This is another case when educating developers and contractors will be paramount for a smooth transition.

Staff is interested in what stakeholders feel on this subject.

Volt-Watt Process/Reporting

Volt-watt reporting is covered by DO-17 in IREC's decision matrix. This would report when a customer is curtailed based on voltage that the customer has no control over. The curtailment kicks in at 106% of voltage. Customers may be curtailed, sometimes severely. In describing the California experience, it appears that there were relatively few customers curtailed, and generally, those curtailed were limited. For PG&E there were nine customers with potential curtailment over 4%, with the highest at 38.7% due to a failing distribution transformer. While the functionality was turned on in 2019, the reporting and implementation of reporting in California did not start until 2021.

It appears the utilities have the AMI equipment necessary to perform such reporting, but more research is needed. There may not be enough bandwidth to collect the necessary information. The utilities agreed to do further research.

Staff would like to know what current capabilities are, if there have been curtailments, how often, how severe. Do stakeholders believe this is an issue that needs to be tracked at this point? Finally – are there current processes that could be leveraged if the decision is to track curtailments.

Normal Ramp Rate

Discussion next focused on normal ramp rate (NRR). This is not required by IEEE 1547, but could avoid rapid voltage changes. From the discussion it appears that this is not a problem currently. The small generators are generally diverse enough that there is no issue. PacifiCorp has some experience, and has not noticed any issues with the batteries in Utah under their battery control program.

Staff is curious about stakeholder positions on this issue, do they believe incorporation of NRR would be helpful. Also, Staff is interested in utility experience.

Nameplate ratings

Decision 19 address nameplate ratings and suggests addressing issues related to volt-watt, limit maximum active power, and frequency droop. A simple example provided demonstrated curtailment based on volt-watt function would be different for a resource based on nameplate versus a different value, based on maximum output. There was limited discussion on this topic.

Staff would like to know more about what stakeholders see as the approach to this topic. Is guidance needed for these factors?

Next Steps

The following table identifies next steps for the fourth workshops. Staff has identified questions above where responses with written justification of positions would be useful, but, as always, invite comment beyond these areas.

<table>
<tr><th colspan="4">IEEE 1547 Workstream</th></tr>
<tr><th>Description</th><td>Event Date</td><td>Workshop Topic</td><td>Pre-meeting deliverable</td></tr>
<tr><td>Workshop 4</td><td>November 17, 2022*</td><td>Discussion on near- and mid-term items as necessary, discussion of long-term issues</td><td>Stakeholders approached to mid-term issues not finalized at the October 25 workshop</td></tr>
<tr><td>Workshop 5</td><td>December 20, 2022</td><td colspan="2" rowspan="4">TBD – future workshop topics will be dependent on progress made in the prior meetings.</td></tr>
<tr><td>Workshop 6</td><td>January 31, 2023</td></tr>
<tr><td>Workshop 7</td><td>February 28, 2023</td></tr>
<tr><td>Workshop 8</td><td>March 28, 2023</td></tr>
<tr><td colspan="4">*Please note the change in date for Workshop 4</td></tr>
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Staff appreciates stakeholders taking the time to participate in these discussions. To make these productive as possible, *Staff would like to know, as early as practicable, if utility technical experts are unavailable to attend future workshops.* If necessary we will look to reschedule such meetings.

As mentioned earlier, Staff requests stakeholders circulate response, redlines, comments, etc. to the Service List as listed on the OPUC UM 2111 webpage.

For any questions or concerns please contact:
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To receive meeting notices and agendas for this docket, send an email to puc.hearings@puc.oregon.gov, and ask to be added to the service list for Docket No. UM 2111. You will then receive emails with workshop details, when new documents have been added to the docket, or there is a change to the schedule.