2021 PSE Integrated Resource Plan

Appendices A-M

January 2021

DRAFT

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A Public Participation

This appendix describes public involvement in the development of the 2021 PSE IRP.

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1. OVERVIEW

Public engagement is both a required and essential part of developing PSE's Integrated Resource Plan. For this IRP, PSE adopted guidelines from the International Association of Public Participation (IAP2), expanded its outreach to stakeholders, and developed a structure to increase PSE's accountability to stakeholders and clearly demonstrate how stakeholder feedback was incorporated in the IRP.

This engagement generated valuable constructive feedback, and the suggestions and practical information received from organizations and individuals helped to guide both the public participation process and inform key components of the 2021 IRP analysis. We thank those who took part for both the time and energy they invested, and we encourage their continued participation.

By the time the draft 2021 IRP is filed with the WUTC, 11 public meetings will have been held, as well as dozens of informal meetings, phone and email communications. More than 175 individuals representing 75 advocacy groups, regulators, industries, customers and interested members of the public have participated. Two additional meetings will be held by the time the final 2021 IRP is filed with the WUTC, and those meetings will be added to this record.

All materials related to the 2021 PSE IRP public participation process can be found at pse.com/irp. This includes meeting agendas; presentations and datasets; meeting recordings, attendance and chat transcripts; Feedback Reports; and Consultation Updates. The meeting attendance and chat transcripts, Feedback Reports and Consultation Updates are also attached to this Appendix.

PSE hired stakeholder engagement specialists to help develop the Public Participation Plan, provide independent meeting facilitation, develop meeting and public comment guidelines, assist with the meeting documentation, and suggest adjustments to the meetings to promote communication and stakeholder engagement. The consultant supporting the 2021 IRP public participation process was EnviroIssues.

2. 2021 PSE IRP PUBLIC PARTICIPATION PLAN

The IAP2 public participation framework was introduced to PSE by stakeholders during the 2019 IRP public engagement process and adopted by PSE for the 2021 IRP. The IAP2 framework, along with various public participation techniques, allowed PSE to design and implement an effective process that allowed stakeholders to clearly understand where they could influence components of key inputs, assumptions and decisions. All meetings were open to all people and there were no exclusions to participation in any topic. Due to COVID-19, all stakeholder engagement was virtual, using various online platforms. Although online platforms are no replacement for in-person meetings and discussions, we believe this resulted in increased participation by a more diverse group of stakeholders from our service territory compared to past IRPs.

IAP2 Framework

IAP2 uses a framework for the level of influence stakeholders can have in a public process called the Spectrum of Public Participation (Spectrum). To identify the role of stakeholders on this spectrum, the IRP project team considered how stakeholder input will be used, what stakeholder input can change, and how stakeholder input will affect the subsequent planning processes in the long term. PSE identified three types of engagement on the spectrum that were most important in its planning for public participation. They were:

> **To inform:** To provide the public with balanced and objective information to assist them in understanding the problem, alternatives and/or solutions
>
> **To consult:** To obtain public feedback on analysis, alternatives and/or decisions
>
> **To involve:** To work directly with the public throughout the process to ensure that public concerns and aspirations are consistently understood and considered.

Given the time constraints for the 2021 IRP, the remote nature of participation due to COVID-19, and the use of established technical methodology to complete the 2021 IRP, the team elected to *inform* stakeholders of IRP progress at key decision points, and to *consult and involve* groups of stakeholders to provide input on certain IRP components throughout the process.

During the 2021 IRP, PSE promised to:

- Keep stakeholders informed of the IRP process, draft and filings to assist them in understanding the IRP.
- Listen to and acknowledge concerns and aspirations from highly impacted stakeholders and to demonstrate how public feedback influenced decisions.

Key Messages

During the 2021 IRP process, PSE focused on the following key messages:

- PSE is developing a plan that identifies how we provide cost-effective electricity to our customers for the next twenty years. The plan helps guide investments in acquiring energy to ensure customer needs are met, while also considering social and environmental concerns.
- PSE believes stakeholder input can and should improve the 2021 IRP and will clearly identify where and how stakeholder input can inform the plan.
- Requirements in the Washington State Clean Energy Transformation Act will be reflected in the 2021 IRP, including development of a 10-year Clean Energy Action Plan.
- The IRP will carefully consider the impacts of various conservation and energy resources against the needs and barriers faced by low-income and other vulnerable communities.
- Informing, involving and consulting stakeholders will help ensure that a comprehensive set of elements are considered in developing the IRP.
- PSE is working to integrate the IRP process with the Delivery System Planning process so stakeholders understand the interconnection and can easily participate in both.
- PSE will seek input on how to improve stakeholder involvement in future plans.

IRP Milestones, Public Participation Techniques and Objectives

Setting IRP Milestones

The IAP2 framework for effective public participation identifies the need for strong linkages and integration of public participation and technical work. In order to identify the key project milestones and decision points where stakeholders should be informed, or where PSE should work with stakeholders to receive input on project components, EnviroIssues worked with the IRP technical team in a workshop to align technical work with specific participation objectives and place them on the IRP development timeline.

Clear objectives then lead to selection of participation techniques to promote PSE meeting those objectives. The goal was for PSE technical staff to work with stakeholders on the coordination of project milestones by aligning participation objectives and techniques, and clearly communicating when stakeholders have the opportunity to provide input and feedback to specific IRP topics.

Participation Techniques and Objectives

WEBSITE IMPROVEMENTS: The project website was redesigned in early 2020 to facilitate pubic involvement. All Webinar registration information, agendas, presentation materials and technical documents, Feedback Reports and Consultation Updates were posted to pse.com/irp. An online Feedback Form invited stakeholders to provide input, suggestions and comments. To evaluate the technique, the website was monitored for time spent on site, pages visited and trends in visits over time.

PUBLIC WEBINARS. PSE was not able to conduct in-person meetings due to COVID-19 restrictions, and as a result online webinars replaced in-person meetings. These webinars were designed to inform, consult and involve stakeholders on key milestones and topics involved in the development of the IRP. During each webinar, stakeholders were able to ask questions and make comments verbally or through the online chat feature. Participation was facilitated by EnviroIssues to allow PSE to focus on the technical content of the presentations. If a question was not answered during the meeting, it was added to the meeting Feedback Report and PSE responded in writing. **One week before each webinar**, meeting reminders were emailed to alert stakeholders that the meeting materials had been posted to pse.com/irp and Feedback Forms were open. **One day after each meeting**, PSE posted the webinar recordings and chat transcripts to pse.com/irp.

WEBINAR RECORDINGS. All webinars were recorded and posted online **one day after the meeting**. The recordings included a voice recording, thumbnail versions of the slides used to support the meeting discussion and a written transcript for easy searching. Speakers' names are included in the transcript. The webinar recordings were used to promote participation by stakeholders who could not attend but wanted to stay involved and provide feedback. PSE accepted all stakeholder feedback, whether a stakeholder attended the webinar or not.

WEBINAR Q&A (chat) LOG. GoToMeeting was the primary online platform used to support the Webinars. All comments and questions received through the online chat were documented in the Webinar Q&A Log and posted online **one day after each meeting**. The chat log documentation includes a list of all attendees along with a name, timestamp and the comment made by each participant. Questions asked via the chat or verbally were answered by PSE verbally and are captured on the webinar recording. Any questions not answered during the webinar were added to the Feedback Report and answered by PSE in writing.

FEEDBACK FORMS. An online Feedback Form at pse.com/irp was designed to promote topic-specific suggestions and questions related to each public webinar. The feedback form was opened one week before the webinar and feedback was due one week after the meeting. Stakeholders used the Feedback Form to submit questions regarding the webinar presentation in advance of the meeting, and PSE typically answered those questions during the meeting. Following the webinar, stakeholders used the Feedback Form to provide specific input to PSE regarding the IRP analysis and materials presented. **At all times** stakeholders could submit questions and comments at pse.com/irp to a general comment form.

FEEDBACK REPORTS were posted to pse.com/irp **two weeks after each meeting.** These reports included all input, questions and comments received from stakeholders and written PSE responses to all feedback. The goal was to promote PSE accountability and foster two-way communication. When PSE did not have sufficient time to respond to all stakeholder feedback and/or if follow-up meetings were necessary to clarify input, PSE provided a response in the Consultation Update.

FOLLOW-UP MEETINGS. Follow-up meetings to the Feedback Reports allowed PSE to engage with stakeholders to clarify their input and/or engage in dialog. These gatherings were organized on an as needed basis and helped to further develop PSE's Consultation Updates.

CONSULTATION UPDATES were posted to pse.com/irp **three weeks after each meeting**. These summaries of the consultation activity (follow-up calls and meetings, etc.) and feedback received reported on how PSE responded to feedback and documented how PSE incorporated the feedback into the IRP.

OTHER COMMUNICATION TOOLS UTILIZED

In addition to the techniques described above, PSE also used the following communications tools.

- PSE conducted Interviews with stakeholders to discuss key concerns and explore process improvements.
- Email was used for reminders about upcoming deadlines, webinars and registration information, and invitations to submit Feedback Forms and participate in surveys.
- Periodic email newsletters reminded stakeholders about upcoming webinars and deadlines and included summaries of stakeholder feedback and updates on the status of the IRP's development.

Dozens of informal meetings, phone and email communications supplemented these communications.

3. ADDITIONAL CONSIDERATIONS

Increasing Engagement

To begin planning for IRP public participation, the project team participated in a workshop led by EnviroIssues, a public participation consulting firm. At the workshop, the project team identified possible audiences and stakeholders who may be interested in or impacted by the IRP. The team then brainstormed possible issues, concerns and aspirations the various audiences may have regarding the IRP and its implementation. The technical team and EnviroIssues then worked to correlate those audiences and issues, tracking which issues could be most important to each audience.

This correlation was used to identify the level of impact the IRP could have on each audience. The audiences were then sorted into categories and prioritized by their relative level of impact and/or interest. This assessment resulted in three tiers of stakeholders: primary, secondary and tertiary. The team was careful to recognize that the assessment was only a snapshot and that ongoing adjustments and clarifications would be necessary throughout the process as more was learned from different audiences and as audiences became more or less interested throughout the process. The stakeholder prioritization tiers determined by the IRP team are described below.

PRIMARY STAKEHOLDERS

- Internal PSE groups whose work is directly impacted by IRP results
- Energy regulatory groups
- Government representatives
- Highly vulnerable populations and their advocates
- Energy sector developers and producers
- Energy councils and coalitions directly impacted by IRP results
- Environmental groups previously involved in stakeholder processes
- Community groups previously involved in stakeholder processes
- PSE ratepayers

SECONDARY STAKEHOLDERS

- Internal PSE groups that experience fewer impacts from IRP results
- Environmental groups not previously involved in stakeholder processes
- Community groups not previously involved in stakeholder processes
- Energy sector organizations indirectly impacted by IRP results
- Labor organizations in energy industries

TERTIARY STAKEHOLDERS

Internal PSE groups that do not experience direct impacts from IRP results

Community groups with an indirect interest in IRP results

Land use interest groups

Customer groups with indirect impacts from IRP results

The following principles of participation were applied to the stakeholder tiers:

All stakeholders (primary, secondary and tertiary) are informed about all participation opportunities (information techniques)

All stakeholders (primary, secondary and tertiary) are welcome to participate in all participation opportunities

Primary stakeholders are specifically invited to participate in engagement opportunities

Once the stakeholder groups were identified, PSE developed an IRP participation list of more than 1,500 possible interested participants with input from regulators, stakeholders and PSE community outreach specialists. PSE provided targeted IRP information and maintained ongoing communication throughout the process with the three tiers of stakeholders. All stakeholders were welcome to participate in all aspects of the IRP process, join the webinars and provide feedback to PSE.

STAKEHOLDER INTERVIEWS. In April and May 2020, the project team conducted interviews with 15 stakeholders who had participated in the 2019 IRP Process. The full summary is available here: https://oohpseirp.blob.core.windows.net/media/Default/documents/2020_0513_StakeholderInterviewSummary_Final.pdf

Key take-aways from the interviews included identifying the topics of greatest interest to stakeholders, the importance of inclusive stakeholder engagement, preserving effective participation strategies and suggestions for building trust and transparency.

Greatest topics of interest in May 2020:

- Load and price forecasting
- Implementation of CETA (Clean Energy Transformation Act)
- Social cost of carbon
- Electrification and renewables
- Demand response planning

- Electric and gas transmission

Stakeholders also suggested additional participants to increase the diversity of participation in the 2021 IRP, and PSE used these suggestions in developing its expanded email distribution list.

ATTENDANCE AND FEEDBACK PARTICIPATION. Webinar meeting attendance ranged from 61 to 81, with 67 being the average. The lowest attendance recorded was at Webinar 1 and the highest at Webinars 7 and 10, demonstrating increased engagement though the process. The number of individual participants who submitted Feedback Forms ranged from 7 to 17 per meeting, with 11 being the average. The number of separate questions and comments ranged from 23 to 114 with 58 being the average. Thirty-eight individuals submitted questions and comments via the online Feedback Form with between 7 and 17 people participating in this way per meeting. Individuals submitted between one and 26 questions per meeting.

PSE provided responses to all questions, comments and feedback as documented in the Feedback Reports or Consultation Updates.

Greater Integration of Delivery System Planning

Public engagement and participation in delivery system planning is becoming increasingly important, and over time, the goal is for the IRP and delivery system planning stakeholder engagement processes to become closely integrated. The 2021 IRP begins this process by integrating delivery system planning into the public participation process more intentionally than in previous cycles.

Discussion of delivery system and grid modernization issues was featured in three of the 12 public meetings (Webinars) held during this cycle. The July 14, 2020 Demand-side Resources and Demand Response meeting included discussion of efforts to reduce energy use by reducing the voltage of specific delivery system circuits while remaining within required tolerances. The August 11, 2020 Portfolio Sensitivities and CETA meeting included a presentation on distributed energy resources (DERs), PSE's first DER Forecast and non-wires analyses, and DER pilots and enablement activities. The November 16, 2020 meeting on the Clean Energy Action Plan, 10-year Distribution and Transmission Plan, and Economic, Health and Environmental Benefits Assessment included discussion of integrating delivery system planning and the IRP, current system needs that may be solved by DERs, and the modernization necessary to support large-scale DERs in the local system. The February 10, 2021, webinar will include preliminary solutions to identified needs and 10-Year Distribution System plan details. In the 2019 IRP Process, the delivery system planning process and projects were shared only with the IRP Technical Advisory Group (TAG) at two meetings.

PSE is also working to integrate the new stakeholder requirements regarding regional transmission into the IRP Public Participation Plan, as described in the regional transmission planning process in Attachment K of PSE's OATT. The stakeholder engagement process for transmission has historically been a process separate from the IRP; in this IRP cycle, transmission will be addressed in the February 10, 2021 public meeting, as mentioned previously.

DER Planning and Delivery System Planning

Distributed Energy Resources Planning RCW 19.280.100 recommends the distribution system investment planning process should utilize a transparent approach that involves opportunities for stakeholder input and feedback. This recommendation is initially met through integration in the 2021 IRP Public Participation Plan.

In 2019, PSE began planning for the establishment of a technical panel to provide input on specific distributed energy issues similar to the way the Conservation Advisory Group (CRAG), Low Income Advisory Group, Low Income Advisory Group and Equity Advisory Group have provided input to the IRP process. This group would monitor approaches implemented in jurisdictions like California and Hawaii that have more mature experience in implementing non-traditional solutions for both resource and delivery system planning; build a common understanding of the challenges, opportunities and trade-offs involved in modernizing the grid to better serve customers; promote collaboration and the best delivery system solutions; and help to further the public participation recommendations set forth by RCW 19.280.100. The input from these specific, focused, technical conversations will inform the IRP process and IRP stakeholder process in the future. To date, PSE has engaged several consultants to investigate potential public engagement frameworks and engaged the WUTC for input and feedback in early 2019. Currently, PSE is identifying expert members to be part of the technical panel. COVID-19 and the larger need to plan holistically for all the stakeholder processes slowed this effort, but we expect to launch the technical panel in 2021.

In the meantime, PSE has led in gathering a group of Washington utilities, called the Washington Utility Symposium, to share and learn from each other as each utility develops DER and non-wire approaches. On July 23, 2020, the planning kickoff meeting was held to gather interest and topics. On September 9, 2020, the first topic meeting discussed how utilities were organized around DER and non-wire processes. On October 29, 2020 the second topic meeting discussed tools, models and data management. Each utility participant is actively engaged in growing its processes, and the opportunity to safely learn from each other and share best practices will benefit all members of the group.

PSE continues its strong stakeholder engagement process as location-specific projects are implemented, leveraging community advisory groups, interactive websites and any and all permitting public processes.

4. PARTICIPANTS

At the time of this writing, 76 organizations and 182 unique individuals participated in development of the 2021 PSE IRP. The participating organizations include the following.

350 Seattle
Absaroka Energy LLC
Alliance of Western Energy Consumers
ARUP
Avangrid Renewables
Avista
Bridle Trails
Broadreach Power
Cascade Natural Gas
City of Arlington
City of Kenmore
City of Bellevue
City of Mercer Island
City of Puyallup
City of Seattle, Office of Sustainability and Environment
Climate Reality Project
Climate Solutions
Coalition of Eastside Neighborhoods for Sensible Energy (CENSE)
DNV GL
Enbala
Evergreen University
FISH (Friends of the Issaquah Salmon Hatchery)
Flex Charging
FortisBC
Franklin Energy
Halmark
Hardy Energy
Impact Bioenergy
Invenergy
juwi Inc.
King County
LBNL; LBNL Consultant to UTC
League of Women Voters

Longroad Energy
Markell & Company LLC
Monolith Energy Consulting
National Grid Ventures
NextEra Energy Resources
Northwest Gas Association
Northwest Independent Power Producers Coalition (NIPPC)
Northwest Pipeline
Northwest Power and Conservation Council
Northwest Power Consulting
NW Energy Coalition (NWEC)
Obsidian Renewables, LLC
Office of the Attorney General Public Counsel Unit
Optimum Building Consultants
Orion Renewable Energy Group
PA Consulting Group
Pacific Northwest Utilities Conference Committee (PNUCC)
Panamint Capital LLC
Pasco Energy
Port of Olympia
Port of Tacoma
Prisma Energy
Renewable Energy Coalition
Renewable Northwest
Sapere Consulting
Shifted Energy
Smart Wires
Solar Horizon
The Sierra Club
Thurston County League of Women Voters
Town of La Conner
TransAlta
TrasAlta Renewables (RNW)
UniEnergy Technologies, LLC
Union of Concerned Scientists
United States Postal Service (USPS)
Vashon Climate Action Group
Wartsila
Washington Environmental Council

Washington State Department of Commerce
Washington State Office of the Attorney General, Office of the Attorney General Public Counsel Unit
Western Grid Group (WGG)
WUTC policy staff and advocacy staff

5. TIMELINE, MEETINGS AND TOPICS

All meetings for the 2021 IRP public participation process were conducted remotely because of COVID-19 restrictions. Each meeting was opened with an orientation that explained how to participate using the electronic platform.

January 2020

Week-long IAP2 training (Foundations and Public Participation) for PSE IRP Stakeholder Manager.

February 2020

Two-day IAP2 training for PSE IRP project team and selected PSE staff.

March 2020

Stakeholder interviews, development of broader participant list, exploration of process improvements. Development of the public participation plan.

April 2020

2021 IRP Work Plan and Public Participation Plan filed with the WUTC and published on the IRP website. All changes to the public participation plan were filed with the WUTC and communicated via the website and meeting announcements.

May 2020

May 12 - Invitation emailed to expanded list of 1,500 individuals that described the public participation process, explained "What is an IRP?", encouraged participation, provided a registration link to the first meeting and a sign-up or opt out option for notifications concerning the process.

May 21 - Reminder emailed for May 28 Webinar 1, Generic Resource Assumptions. Meeting materials posted to pse.com/irp and Feedback Form opened. Registration encouraged and information and registration link for June 10 Webinar 2 also included.

May 28 – Webinar 1
Generic Resource Assumptions

Stakeholder role: Consult
Meeting platform: GoToWebinar
Attendance: 61 participants and the IRP project team

Orientation included the role of the IAP2 public participation process in the 2021 IRP and how to use the Feedback Form. The PSE IRP team presented an overview of IRP modeling and the schedule; described changes made to generic resource assumptions since the 2019 IRP Process; and posted a spreadsheet summarizing the generic resource assumptions for the 2021 IRP. Feedback Forms were used for the first time at this meeting. S*takeholders shared their input on generic resource costs*

May 29 – Webinar 1 recording and chat posted to pse.com/irp.

June 2020

June 4 – Newsletter and reminder for the June 10 Webinar 2, Electric Price Forecasting, plus a reminder about the deadline for Webinar 1 feedback, and a "save the date" notice for Webinar 3. Webinar 2 materials posted to pse.com/irp and Feedback Form opened.

June 4 – Feedback forms due for Webinar 1, Generic Resource Costs; 18 individuals responded with questions and comments.

June 9 – Second reminder emailed for Webinar 2, Electric Price Forecast.

June 11 – Feedback Report for Webinar 1, Generic Resource Costs, posted to pse.com/irp with PSE responses to 54 questions and comments received from stakeholders.

June 10, 2020 – Webinar 2
Electric Price Forecast

Stakeholder role: Inform
Meeting platform: GoTo Meeting, in response to stakeholder concerns about the limitations of GoToWebinar.
Attendance: 68 participants and the IRP project team

The PSE team explained how the electric price forecast is used in the IRP to complete scenarios; described the modeling process; reviewed the electric price forecasts from the 2017 IRP and 2019 IRP Process and results of the draft 2021 IRP electric price forecast; reviewed CETA regulation assumptions; and reviewed 2021 IRP electric price scenarios. *Stakeholders shared their input on incorporating clean energy policies in baseline assumptions to inform the electric price forecast.*

June 11 – Webinar 2 recording and chat posted to pse.com/irp.

June 17 – Feedback forms due for Webinar 2, Electric Price Forecast; 7 individuals responded.

June 18 – Consultation Update on Webinar 1, Generic Resource Costs, posted to pse.com. The IRP team reported decisions on what costs to use and supplied the documentation used to make the decisions. *Generic resource costs were adjusted based on stakeholder feedback and an updated file was posted to pse.com/irp.*

June 23 – Reminder emailed for June 30 Webinar 3, Transmission Constraints. Meeting materials posted to pse.com/irp and Feedback Form opened.

June 24 – Feedback Report for Webinar 2, Electric Price Forecast, posted to pse.com/irp with PSE responses to 64 questions and comments received from stakeholders.

June 29 – Second reminder emailed for Webinar 3, Transmission Constraints.

June 30, 2020 – Meeting Webinar 3 Transmission Constraints

Stakeholder role: Consult
Meeting platform: Zoom was tested as another meeting platform option.
Attendance: 74 participants and the IRP project team

The IRP project team presented background concerning transmission constraints and discussed transmission capacity constraints with participants (modeling methodology, capacity magnitudes and capacity uncertainty). A transmission cost assumption presentation included transmission rates and losses in the 2021 IRP. *Stakeholders shared their feedback on how to account for transmission availability with restricting resource builds.*

July 2020

July 1 – Webinar 3 recording and chat posted to pse.com/irp.

July 1 – Consultation Update on Webinar 2, Electric Price Forecast, posted to pse.com/IRP. The IRP team reported its decisions on what prices to use and the documentation used to arrive at the decisions.

July 7 – Feedback Forms due for Webinar 3, Transmission Constraints; 12 individuals responded.

July 8 - Reminder email for July 14 Webinar 4, Demand-side Resources and Demand Response. Meeting materials posted to pse.com/irp and Feedback Form opened.

July 13 - Second reminder emailed for Webinar 4, Demand-side Resources and Demand Response.

July 14 – Feedback Report for Webinar 3, Transmission Constraints, posted on pse.com/irp with PSE responses to 68 questions and comments.

July 21 – Consultation Update on Webinar 3, Transmission Constraints, posted to pse.com/irp. PSE reported decisions on what transmission constraints to use in the analysis.

July 14, 2020 – Webinar 4
Demand-side Resources and Demand Response

Stakeholder role: Inform and Consult
Meeting platform: GoToWebinar was chosen as the platform for the remaining meetings based on stakeholder and PSE experience.
Attendance: 69 participants and the IRP project team

The IRP project team explained how the Conservation Potential Assessment (CPA) and Demand-Side Response Assessment is used in the IRP and described the methodology used in that assessment; explained electric DSR potential, natural gas DSR potential and distribution efficiency; and described how the CPA results are input into IRP modeling. In addition to PSE staff presentations, a representative of Cadmus presented the results of the CPA draft report. *Stakeholders learned about and shared their feedback on demand response programs and the costs and saving assumptions to be included in the conservation measures.*

July 15 – Webinar 4 recording and chat posted to pse.com/irp.

July 15 – Reminder email for July 21 Webinar 5, Social Cost of Carbon. Meeting materials posted to pse.com/irp and Feedback Form opened.

July 20 – Second reminder email for July 21 Webinar 5, Social Cost of Carbon.

July 21 – Feedback Forms due for Webinar 4, Demand-side Resources and Demand Response; 17 individuals responded.

July 21, 2020 – Webinar 5
Social Cost of Carbon/Social Cost of Greenhouse Gases and Upstream Emissions

Stakeholder role: Consult and Inform
Attendance: 54 participants and the IRP project team

Note: PSE views the terms social cost of greenhouse gases (SCGHG) and social cost of carbon (SCC) as interchangeable and therefore referenced them as SCC/SCGHG in the IRP models and in this meeting. In this webinar, PSE explained the SCC/ SCGHG according to CETA regulations, and presented the implications of modeling SCC/SCGHG as a cost adder vs. a tax, giving examples of the applications of each approach and the methodology. Background concerning the conclusions developed during the 2019 IRP Process was also provided for context, and SCC/SCGHG integration in the scenarios and portfolio sensitivities was described. The methodology to calculate upstream natural gas emissions was a review of the material presented in the 2019 IRP Process. *Stakeholders shared their input on why PSE should be utilizing the high social cost of carbon and learned about PSE's upstream emissions calculations.*

July 22 – Webinar 5 recording and chat posted to pse.com/irp.

July 28 – Feedback Report posted for Webinar 4, Demand-side Resources and Demand Response, with PSE responses to 114 questions and comments.

July 28 – Feedback Forms due for Webinar 5, Social Cost of Carbon and Upstream Emissions; 11 individuals responded.

August 2020

August 4 – Consultation Report on Webinar 4, Demand-side Resources and Demand Response posted to pse.com/irp.

August 4 – Feedback Report posted for Webinar 5, Social Cost of Carbon and Upstream Emissions, with PSE responses to 38 questions and comments. On August 25, an addendum to this Feedback Report was posted with PSE responses to an additional 8 questions and comments from NWEC's feedback. A total of 46 questions and comments were responded to on this topic.

August 5 – Reminder email for August 11 Webinar 6, Scenarios, Sensitivities and Distributed Energy Resources. Meeting materials posted to pse.com/irp and Feedback Form opened.

August 10 - Second reminder emailed for August 11 Webinar 6, Scenarios, Sensitivities and Distributed Energy Resources.

August 11 – Consultation Update on Webinar 5, Social Cost of Carbon and Upstream Emissions, posted on pse.com.

August 11, 2020 – Webinar 6
Scenarios and Portfolio Sensitivities Development (electric and gas) and Distributed Energy Resources

Stakeholder role: Involve and Inform
Attendance: 69 participants and the IRP project team

The meeting content included portfolio scenarios and sensitivities, CETA assumptions, distributed energy resource integration, and a consultation update briefing on how stakeholder feedback has been included in the 2021 electric price forecast. *Stakeholders provided their thoughts and aspirations about what portfolio sensitivities PSE should consider modeling and learned that PSE will model 80 percent and 100 percent renewable portfolio targets.*

August 12 – Webinar 6 recording and chat posted to pse.com/irp.

August 18 - Feedback Forms due for Webinar 6, Scenarios, Sensitivities and Distributed Energy Resources; 8 individuals responded.

August 25 – Feedback Report on Webinar 6, Scenarios, Sensitivities and Distributed Energy Resources, posted on pse.com/irp with PSE responses to 38 questions and comments.

August 26 – Reminder email for Sept. 1 Webinar 7, Demand Forecast, Resource Adequacy, Resource Need and CETA Assumptions. Meeting materials posted to pse.com/irp and Feedback Form opened.

August 31 – Second reminder emailed for Sept. 1 Webinar 7, Demand Forecast, Resource Adequacy, Resource Need and CETA Assumptions.

September 2020

Sept. 1 – Consultation Update on Webinar 6, Scenarios, Sensitivities and Distributed Energy Resources, posted on pse.com/irp, including an updated list of scenarios and sensitivities based on stakeholder feedback.

September 1, 2020 – Webinar 7 Demand Forecast (electric and gas), Resource Adequacy, Resource Need (peak capacity, energy & renewable energy need), CETA Assumptions

Stakeholder role: Inform and Consult
Attendance: 81 participants and the IRP project team

At this meeting, stakeholders learned about PSE's 2021 IRP gas and electric demand forecasts, the resource adequacy analysis and draft resource adequacy results. *Stakeholders also had an opportunity to give feedback and suggestions on CETA alternative compliance.*

Sept. 2 – Webinar recording and chat posted to pse.com/irp.

Sept. 8 – Feedback Forms due for Webinar *7,* Demand Forecast, Resource *Adequacy*, Resource Need and CETA Assumptions; 5 individuals responded.

Sept 15 – Feedback Report on for Webinar 7, Demand Forecast, Resource Adequacy, Resource Need and CETA Assumptions, posted on pse.com/irp with PSE responses to 23 questions and comments.

Sept. 22 – Consultation Update for Webinar 7, Demand Forecast, Resource Adequacy, Resource Need and CETA Assumptions, posted to pse.com/irp.

Sept 30 – Newsletter emailed communicating of the launch of Delivery System Planning process on pse.com/irp. A review of the status of the 2021 IRP process was provided, along with a link to a survey to determine interest in PSE providing an introduction to the IRP seminar or "IRP 101." *PSE received interest from six individuals and therefore concluded to revisit this proposal for the next IRP.*

October 2020

Oct. 9 – Reminder email for Oct. 14 Webinar 8, Natural Gas IRP. Meeting materials posted to pse.com/irp and Feedback Form opened.

October 14, 2020 – Webinar 8
Natural Gas IRP: Design Peak Day, Gas Portfolio Modeling and Draft Results, Resource Alternatives, Scenarios and Portfolio Sensitivities Review

Stakeholder role: Involve and Inform
Attendance: 51 participants attended in addition to the PSE project team

Stakeholders learned about PSE's natural gas peak day planning standard, natural gas resource alternatives and draft natural gas portfolio results. *Stakeholders had the opportunity to give feedback and suggestions on natural gas scenarios and portfolio sensitivities.*

Oct 15 – Webinar 8 recording and chat posted to pse.com/irp.

Oct 19 – Emailed invitation to participate via survey in selecting the electric portfolio sensitivities to be analyzed in the 2021 IRP.

October 20, 2020 – Webinar 9
Electric Portfolio Modeling Process, Final Electric Power Prices, Electric Sensitivities, Inputs and Observations from Draft Results

Stakeholder role: Involve and Inform
Attendance: 62 participants and the PSE project team

The IRP team explained the electric IRP analysis process (portfolio modeling, final resource adequacy analysis, final resource need, final electric price forecast, planning assumptions and resource alternatives) and electric portfolio sensitivities. S*takeholders learned about PSE's final electric price forecast, shared their thoughts and aspirations about PSE's draft electric portfolio* *results, and provided input on the electric portfolio and sensitivities.*

Oct 19 – Oct 27 – To gain greater understanding of stakeholder priorities for the IRP, PSE invited stakeholders to participate in selecting electric sensitivities via a Sensitivity Prioritization Survey fielded from October 20 to October 27. The survey link was distributed via email and made available online.

Sensitivities are important for determining the reasonableness of the portfolio. PSE uses a mathematical model that optimizes the portfolio to the lowest reasonable cost for a given set of assumptions, but there are many possible futures. Sensitivities make it possible to analyze how different regulations or conditions would impact the mix of resources. For example: Does the mix of new resources change? Does the portfolio cost change? Do portfolio emissions change?

In addition to prioritizing various sensitivity analyses, the survey gathered feedback on two specific sensitivity assumptions: 1) which alternative fuel they thought would be most interesting to model for peaking plants, hydrogen or biodiesel, and 2) which methodology to use to model temperature changes into the future; three options were offered and were discussed at the October 20 webinar.

The survey results were reported to stakeholders in the Webinar 9 Consultation Update on November 10, 2020. Over 140 individuals participated. Figure A-X summarizes the sensitivity prioritization results and how the results were applied to the 2021 IRP modeling process. (Figure A-1 does not include a complete listing of sensitivities included in the 2021 IRP, please refer to Chapter 5 for the complete list of sensitivities.)

Figure A-1: Sensitivity Prioritization Results and Application

Rank	Votes	Survey Number	Sensitivity Name	Sensitivity Description	Application
1	132	35	EV battery to grid	Include an electric vehicle-to-grid resource as a generic resource	Strategies for incorporating electrical vehicle batteries onto the grid are included in a comprehensive discussion of grid modernization efforts in Chapter 4. Also, a forecast of distributed storage resources has been included as a 'must-take' resource in all portfolio scenarios and sensitivities.

Rank	Votes	Survey Number	Sensitivity Name	Sensitivity Description	Application
2	129	21	Use AR5 to model upstream emissions	Quantify upstream emissions using AR5 methodology rather than AR4 methodology	Modeled as Sensitivity K.
3	126	14	6-yr ramp rate	Reduce the ramp rate for conservation measures from 10 years to 6 years	Modeled as Sensitivity F.
4	126	32	Add 185 MW Colstrip Trans-mission	Model additional transmission from the Colstrip substation to PSE service territory	PSE presented an upper transmission capacity limit of 565 MW to Montana in the June 30 and Oct. 20 Webinars. At that time, these values represented the most-likely transmission capacity available to PSE in the region. Since then, negotiations for sale of PSE's portion of Colstrip Unit 4 and its accompanying transmission have ceased, such that PSE can now model 750 MW of available transmission capacity to Montana for all scenarios and sensitivities, making this sensitivity no longer necessary.
5	124	17	Social discount rate for DSR	Reduce the discount rate of demand-side resources from 6.8% to 2.5%	Modeled as Sensitivity H.
6	122	39	SCGHG only (dispatch cost)	Model the social cost of greenhouse gases as a dispatch cost in the absence of other CETA targets	Sensitivity S models the SCGHG in the absence of other CETA targets. However, the SCGHG is modeled as a fixed cost adder to align with SCGHG accounting used in Scenario 1, Mid Economic Conditions. The SCGHG will be modeled as a dispatch cost in sensitivities I and J.

Rank	Votes	Survey Number	Sensitivity Name	Sensitivity Description	Application
7	121	36	Time-of-use pricing	Include time-of-use pricing for conservation and demand response programs	Strategies and benefits associated with time-of-use pricing are included in the comprehensive discussion of grid modernization efforts in Chapter 4. Further research determined modeling constraints do not allow for optimization modeling of time-of-use pricing.
8	121	41	Private solar input testing	Model inclusion of subsidy for solar and electric storage resources	This sensitivity is not explicitly modeled for the 2021 IRP; however, results from Sensitivity C, Distributed Transmission/Build Constraints at Tier 2, will shed light on costs and benefits associated with higher adoption of distributed solar PV resources.
9	120	42	Equity-focused portfolio	A minimum of 50% of new resources must be located in WA state and expansion of community solar programs	In the draft IRP portfolio results, more than 50% of resources are located in WA state in all scenarios and sensitivities. Also, all include increased amounts of conservation and demand response. Given that the Mid Scenario portfolio has already selected conservation in the upper limits of the supply curve, PSE cannot add 150% of cost-effective conservation to the portfolio. PSE has contacted the stakeholder and will work with them to re-define this sensitivity.
10	116	46	Virtual Power Plants (VPP)	VPPs are used to manage distributed energy resources	Virtual power plants are included in a comprehensive discussion of grid modernization efforts in Chapter 4, along with other components of grid modernization (time-of-use pricing and EV battery-to grid).
11	24	26	100% renewable resources by 2030	More aggressive renewable resource adoption; all gas plants retired by 2030	Modeled as Sensitivity N.

Rank	Votes	Survey Number	Sensitivity Name	Sensitivity Description	Application
12	22	28	Carbon reduction	All natural gas plants retired by 2045 and run-time limits are imposed to meet carbon emission targets	Modeled as sensitivity O; however, run-time limits were not imposed prior to 2045. Instead, alternative compliance measures were used to reach carbon neutrality.
13	18	18	High SCGHG	Higher social cost of greenhouse gases than specified by CETA	Given that CETA's renewable requirements are already pushing the portfolio builds, PSE decided to model the CO_2 tax portfolio that received fewer votes.
14	17	9	"Highly Distributed" Trans-mission/ build constraints, Tier 1	Model a significantly transmission constrained system	Sensitivity C models the Tier 2 transmission constraints level, and Sensitivity D models time-delayed transmission. PSE feels these two sensitivities will give enough information to help inform the resource plan, but if time allows, this may be included in the final IRP.
15	13	11	"Highly Centralized Trans-mission/ build constraints, Tier 3	Model a lightly transmission constrained system	Sensitivity C models the Tier 2 transmission level and Sensitivity D models the time-delayed transmission. PSE feels these two sensitivities will give enough information to help inform the resource plan, but if time allows, this may be included in the final IRP.
16	13	12	Trans-mission/ build constraints, time-delayed (option 2)	Model an expanding transmission system over time	Modeled as Sensitivity D.

Rank	Votes	Survey Number	Sensitivity Name	Sensitivity Description	Application
17	13	47	Alternative fuel #2 for peakers	Model a must-run sensitivity of either biodiesel OR hydrogen as an alternative fuel for peaker plants. This sensitivity is a vote to model BOTH biodiesel and hydrogen.	Sensitivity M models biodiesel as an alternative fuel source for peaker plants.
18	12	20	Mid economic conditions with SCGHG as dispatch cost in electric price and portfolio model	Model the social cost of greenhouse gases as a dispatch cost in both the power price and portfolio models	Modeled as sensitivity J.
19	12	33	Fuel switching from electric to gas	Decreases demand in electric portfolio and increases demand in gas portfolio	Given low interest, this will not be modeled in the IRP.
20	11	5	Mid economic conditions plus increased renewable build	Economic conditions and power price forecast adjusted to model 100% renewable energy goal in Oregon	Given low interest, this will not be modeled in the IRP.
21	11	16	Non-energy Impacts	Increase the value of non-energy impacts from adoption of conservation and demand response measures	Modeled as Sensitivity G. Given that non-energy impacts are part of CETA, PSE has prioritized this sensitivity.

Rank	Votes	Survey Number	Sensitivity Name	Sensitivity Description	Application
22	10	24	SCGHG as a tax in WA, OR, CA	Models the social cost of greenhouse gases plus a regional CO_2 tax of $15/ton (adjusted for inflation over time) in WA, OR and CA	Sensitivity L models impacts associated with carbon pricing across all states in the WECC. During the 2017 IRP, PSE modeled a carbon tax in Washington only. This led carbon emissions to shift to other states in the western interconnect and increase WECC-wide emissions. PSE recommends modeling the CO_2 tax as a federal tax across all states to prevent this shift of dispatch and emissions.
23	10	37	Holistic conser-vation approach	Additional information needed to complete this sensitivity	Given low interest, this will not be modeled in the IRP.
24	8	22	Mid economic conditions with SCGHG as a fixed cost plus a federal CO_2 tax	Models the social cost of greenhouse gases plus a federal CO_2 tax	Modeled as Sensitivity L.
25	6	6	Low demand with mid gas prices	Low demand in both power price and demand forecasts and “most-likely” gas price forecast	Given low interest, this will not be modeled in the IRP.
26	6	15	8-yr ramp rate	Reduces the conservation measures ramp from 10 years to 8 years	Given low interest, this will not be modeled in the IRP.

Rank	Votes	Survey Number	Sensitivity Name	Sensitivity Description	Application
27	6	44	2% Cost threshold	Must-take DR and Battery storage before other builds are optimized. Resource additions are constrained to the CETA 2% cost cap, must build demand response and battery storage before gas plants	Sensitivity P models the must-take energy storage. This sensitivity can be compared to the 2% of annual revenue requirement. Sensitivity U looks at the resource plan as compared to the 2% threshold and adjusts the portfolio as necessary.
28	5	4	Low demand with a very high gas price	Mix of low demand and very high gas price forecasts	Given low interest, this will not be modeled in the IRP.
29	5	45	2% cost threshold, renewable over-generation test	Resource additions are constrained to the CETA 2% cost cap, PSE market sales are prohibited	Sensitivity A models renewable overgeneration. This sensitivity can be compared to the 2% of annual revenue requirement. Sensitivity U looks at the resource plan as compared to the 2% threshold and adjusts the portfolio as necessary.
30	2	23	High economic conditions with SCGHG as a dispatch cost in electric prices and portfolio model	The social cost of greenhouse gases as a dispatch cost, with higher-than-expected power price, demand and gas price forecasts	Given low interest, this will not be modeled in the IRP.
31	2	34	High economic conditions with SCGHG as a dispatch cost in portfolio model only	The social cost of greenhouse gases as a dispatch cost, under higher-than-expected power price, demand and gas price forecasts	Given low interest, this will not be modeled in the IRP.

Rank	Votes	Survey Number	Sensitivity Name	Sensitivity Description	Application
32	2	40	Tweaks to resource cost assump-tions	Alter resource cost assumptions for generic resources (further detail forthcoming from WUTC staff)	Given low interest, this will not be modeled in the IRP.

Figure A-2 provides the results of the alternative fuel poll.

Figure A-2: Alternative Fuels Poll Rresults

Rank	Alternate Fuel	Number of Responses
1	Hydrogen	140
2	Biodiesel	16

Figure A-3 provides the results of the temperature sensitivity methodology poll.

Figure A-3: Temperature Sensitivity Methodology Poll Results

Rank	Temperature Methodology	Number of Responses
1	3. Northwest Power and Conservation Council's climate model temperature assumption	93
2	2. Temperature normal based on most recent 15 years of temperature data	43
3	1. Trended normal based on historical observed trends (trended normal analysis completed by Itron Inc., Appendix L)	20

Oct. 21 – Webinar 9 recording and chat posted to pse.com/irp.

Oct. 21 – Feedback Forms due for Webinar 8, Natural Gas Analysis; 13 individuals responded.

Oct. 27 – Newsletter alert: last day to participate in the survey to select the portfolio sensitivities for analysis in the 2021 IRP.

Oct. 27 – Feedback Forms due for Webinar 9, Electric Portfolio Modeling, Power Prices, Sensitivities and Draft Results; 11 individuals responded.

Oct. 28 – Feedback Report on Webinar 8, Natural Gas Analysis, posted to pse.com/irp with PSE responses to 52 questions and comments.

November 2020

Nov. 3 – Feedback Report on Webinar 9, Electric Portfolio Modeling, Power Prices, Sensitivities and Draft Results, posted to pse.com/irp with PSE responses to 71 questions and comments.

Nov. 4 – Consultation Update on Webinar 8, Natural Gas Analysis, posted on pse.com/irp.

Nov. 10 – Consultation Update on Webinar 9, Electric Portfolio Modeling, Power Prices, Sensitivities and Draft Results, posted on pse.com/irp.

Nov. 13 – Reminder emailed for Nov. 16 Webinar 10, CETA, Clean Energy Plan, Health and Environment Benefits, Delivery System and Grid Modernization. Meeting materials posted to pse.com/irp and Feedback Form opened.

November 16, 2020 – Webinar 10
CETA, Clean Energy Action Plan, Clean Energy Implementation Plan, Economic, Health and Environmental Benefits Assessment of Current Conditions, Delivery System and Grid Modernization Needs

Stakeholder role: Consult, Involve and Inform
Attendance: 81 participants and the IRP project team.

The IRP team delivered an overview of the 2021 IRP modeling process and timeline, the Clean Energy Action Plan and Clean Energy Implementation Plan; discussed the PSE's desire and stakeholders' request to give input on initial metrics for the Economic, Health and Environmental Benefits Assessments; gave a CETA rulemaking update; proposed a methodology for assessing current conditions; and presented the delivery system and grid modernization needs for the 10-year transmission and distribution plan. S*takeholders gave feedback and suggestions on the Clean Energy Action Plan and the Clean Energy Implementation Plan; provided their thoughts and aspirations concerning the Economic, Health and Environmental Benefits Assessment of Current Conditions; and learned about PSE's 2021 delivery system and grid modernization needs.*

Nov. 17 – Webinar 10 recording and chat posted to pse.com/irp.

Nov. 20 – Email communication thanking stakeholders for participating in the November 16 meeting and asking stakeholders to provide feedback on the Economic, Health and Environmental Benefits Assessment of Current Conditions, along with specific input PSE is seeking to better inform draft and final IRP.

Nov. 30 – Second reminder email asking stakeholders to provide feedback on the on the Economic, Health and Environmental Benefits Assessment of Current Conditions, along with specific input PSE is seeking to better inform draft and final IRP.

Nov. 30 – Feedback Forms due for Webinar 10, CETA, Clean Energy Plan, Health and Environment Benefits, Delivery System and Grid Modernization; 10 individuals responded.

December 2020

Dec. 7 – Feedback Report on Meeting 10, CETA, Clean Energy Plan, Health and Environment Benefits, Delivery System and Grid Modernization, posted to pse.com/irp with PSE responses to 34 questions and comments.

Dec. 8 – Reminder emailed for Dec. 15 Webinar 11, Flexibility Analysis and Portfolio Draft Results. Meeting materials posted to pse.com/irp and Feedback Form opened.

Dec. 14 – Consultation Update on Webinar 10, CETA, Clean Energy Plan, Health and Environment Benefits, Delivery System and Grid Modernization, posted to pse.com/irp.

Dec. 14 – Second reminder email for Dec. 15 Webinar 11, Flexibility Analysis and Portfolio Draft Results.

Dec 15 – Additional reminder email for Dec 15 Webinar 11, Flexibility Analysis and Portfolio Draft Results. Attached link to uploaded webinar materials, posted to pse.com/irp.

December 15, 2020 – Webinar 11
Flexibility Analysis, Portfolio Draft Results (electric & natural gas)

Stakeholder role: Consult and Involve
Attendance: 88 individuals and the IRP project team.

The meeting content included draft conservation results (electric and gas), draft electric and natural gas results, and flexibility analysis. *At this meeting, stakeholders had an opportunity to* *give feedback and suggestions on the flexibility analysis. Stakeholders provided their thoughts and aspirations concerning the portfolio draft results.*

Dec. 16 – Webinar recording and chat posted to pse.com/irp.

Dec. 28 – Feedback Forms due for Meeting 11, Flexibility Analysis and Portfolio Draft Results; 7 individuals responded.

January 2021

Jan. 4 – Draft 2021 PSE Integrated Resource Plan filed with the Washington Utilities and Transportation Commission.

The following two meetings will occur following the Draft IRP filing date and will be included in the final IRP, which is filed with the WUTC April 1, 2021.

February 2021

February 10, 2021 – Webinar 12
Wholesale Market Risk, Portfolio Draft Results, Delivery System Planning: 10-Year Distribution and Transmission Plan Solutions with Non-Wire Alternatives

Stakeholder role: Consult and Inform
Attendance:

Description to come in the final IRP.

March 2021

March 5, 2021 – Webinar 13
Wholesale Stochastic Analysis, Resource Plan, Clean Energy Action Plan

Stakeholder role: Inform & Consult
Attendance:

Description to come in the final IRP.

6. MEETING ATTENDANCE/CHAT LOG, FEEDBACK REPORTS AND CONSULTATION UPDATES

The chat logs, attendance records, Feedback Reports and Consultation Updates are provided for each Webinar completed so far in the following pages. The final two Webinars will be included in the final IRP filing.

- *Webinar 1, May 28, 2020*
- *Webinar 2, June 10, 2020*
- *Webinar 3, June 30, 2020*
- *Webinar 4, July 14, 2020*
- *Webinar 5, July 21, 2020*
- *Webinar 6, August 11, 2020*
- *Webinar 7, September 1, 2020*
- *Webinar 8, October14, 2020*
- *Webinar 9, October 20, 2020*
- *Webinar 10, November 16, 2020*
- *Webinar 11, December 15, 2020*
- *Webinar 12, February 10, 2021 – to be included in IRP final draft.*
- *Webinar 13, March 5, 2021 – to be included in IRP final draft.*

Webinar #1: Generic Resource Assumptions Q&A

5/29/2020

Overview

On May 28, 2020 Puget Sound Energy hosted a webinar on generic resource assumptions as part of the 2021 Integrated Resource Plan. At this webinar, stakeholders shared their input on generic resource costs. Participants were able to submit feedback on the webinar and materials prior to and after the webinar occurred. Additionally, participants were able to ask questions using a Q&A chat box provided by the GoToWebinar platform.

Below is a verbatim report of the questions submitted to the Q&A chat box. Answers to the questions were provided verbally by IRP staff during the webinar. Timestamps for questions are available for tracking. Please note that questions were answered in order of relevance to the topic currently being discussed. Questions regarding other topics were answered at the end of the webinar session.

To view a recording of the webinar and to hear responses from staff, please visit the project website at pse-irp.participate.online.

Attendees

A total of 61 people attended the meeting.

Attendees included:

Jessica Ackerman, James Adcock, Eleanor Bastian, Larry Becker, Charlie Black, Joni Bosh, Robert Briggs, Rachel Brombaugh, Peter Brown, Stephanie Chase, Vincent Ching, Colin Crowley, Weimin Dang, Cody Duncan, Kara Durbin, Molly Emerson, Ben Farrow, Tom Flynn, Max Greene, Steve Greenleaf, Brian Grunkemeyer, Vladimir Gutman-Britten, Daniel Handal, Fred Heutte, Mike Hopkins, Doug Howell, Laurie Hutchinson, Cameron Janacek, Richard Johnson, Kevin Jones, Eric Kang, Dan Kirschner, Michele Kvam, Sarah Laycock, Virginia Lohr, Jenny Lybeck, Kate Maracas, Kassie Markos, Don Marsh, Sheri Maynard, Jennifer Mersing, David Meyer, Margaret Miller, Valerie O'Halloran, John Ollis, Court Olson, Anthony O'Rourke, Bill Pascoe, David Perk, Nathan Sandvig, Kathi Scanlan, Cindy Song, Steve Johnson Steve Johnson, Rahul Venkatesh, Katie Ware, Charles Weschler, Willard (Bill) Westre, Kendra White, Bob Williams, Scott Williams and Zacarias Yanez.

Questions Received

Questions are posted in the order in which they were received. The webinar began at 1:30 PM PDT and ended at 4:00 PM PDT.

Responses from staff in the chat box were only provided to assist with webinar troubleshooting. They have not been included for brevity.

Time Asked	Name	Question Asked
01:32:44 PM PDT	Doug Howell	Who is speaking?
01:33:28 PM PDT	Doug Howell	Request that questions can be seen by all participants, not just staff.
01:33:34 PM PDT	Virginia Lohr	Have you started?
01:37:32 PM PDT	Doug Howell	May we see who is participating?
01:38:59 PM PDT	Virginia Lohr	We had no audio, but it's working now.
01:40:04 PM PDT	Doug Howell	It is much better to have questions and participants available in real time. This is key to transparency.
01:42:23 PM PDT	Doug Howell	FYI, King County did this very successfully with 70 participants for their climate plan webinar.
01:44:33 PM PDT	James Adcock	I feel PSE IRP's in the past have been more successful when questions can be asked and answered more-or-less in real time, not delayed "until the end" -- when questions are delayed "until the end" they never get answered in a meaningful way.
01:47:26 PM PDT	David Perk	In the 2019 IRP cycle there were a couple of IRPAG meetings that were opportunities for the general public to make comments. Apparently that format won't be available in the 2021 cycle?
01:49:06 PM PDT	James Adcock	I am concerned that the "chat moderator" is "editing" the questions/chat I am posting in a way which does not necessarily accurately represent that which I am actually saying.
01:49:13 PM PDT	Don Marsh	Q&A's on a particular slide must be near real-time to have a good record for the webinar. Otherwise, the continuity is lost for viewers.
01:50:55 PM PDT	Virginia Lohr	What is the difference between QUESTIONS and CHAT?
01:51:53 PM PDT	James Adcock	I was surprised that PSE "canceled" the 2019 IRP Process without even a "Closure Meeting."
01:53:13 PM PDT	David Perk	+1 on James' comment
01:54:41 PM PDT	James Adcock	Will the 2021 IRP meet the 2030 "80/20" requirements?

Time Asked	Name	Question Asked
01:55:39 PM PDT	Virginia Lohr	When are the "On-line Meetings"?
01:56:44 PM PDT	Kevin Jones	WAC 480-100-620 states "The utility must inform, consult, and involve stakeholders in the development of its IRP..." What IAP2 level are you applying to this meeting?
01:58:03 PM PDT	James Adcock	If meeting dates change or are canceled how many weeks notice will we have about those changes? It is very disruptive to our schedules and other commitments to have meeting dates changed or moved with little notice.
02:01:24 PM PDT	James Adcock	Was that a "Yes" committment to meeting the 2030 "80/20" requirements? I did not hear Irena say that in so many words.
02:01:30 PM PDT	Joni Bosh	Did the 2019 progress report include estimated resource need?
02:02:26 PM PDT	Kevin Jones	Since WAC 480-100-620 uses "and", not "or", wouldn't it be more appropriate to apply the "involve" level of public participation to this meeting? If not, why not?
02:02:28 PM PDT	David Perk	Welcome Elizabeth!
02:02:31 PM PDT	Kate Maracas	Will there be phases of the IRP process for which the IAP2 "collaborate" level will be utilized?
02:04:05 PM PDT	Virginia Lohr	You make a distinction between webinars and on-line meetings. When are the on-line meetings and who is invited to them and where can I find information on them? I do not see the distinction on your web site.
02:04:12 PM PDT	Don Marsh	When will the Demand Forecast assumption be discussed? This has been a weak point in previous IRPs, so we want to concentrate on these assumptions.
02:05:14 PM PDT	James Adcock	Can we get access to the input data used for stochastic modeling?
02:06:20 PM PDT	Charlie Black	Elizabeth mentioned PSE's existing resources. How will PSE develop assumptons about costs, availabilities, remaining lives, etc. for PSE's existing generating resources?
02:07:17 PM PDT	Doug Howell	Agree with Jim. We need access to the input files for Plexos, Aurora and the Resource Adequacy models. We will sign NDAs as necessary.
02:09:17 PM PDT	Kate Maracas	Does PSE's capacity expansion model optimize strictly on least cost, or is it configurable to optimize on other parameters associated with particular resources (such as value of flexibility, voltage support, and other ancillary services)?
02:10:55 PM PDT	Nathan Sandvig	How does this upcoming RFP interface with this IRP process?
02:10:56 PM PDT	Charlie Black	Supplement to my question on assumptions about PSE's existing resources: what assumptions are being made about need and costs for reburbishments, other investment costs in the existing resources?
02:14:36 PM PDT	Don Marsh	The location of resources is important. Costs of a resource should include transmission costs, transmission losses, transmission reliability and resiliency, and risks (fires).

Time Asked	Name	Question Asked
02:15:07 PM PDT	Kevin Jones	Hi Alison. WIll you post my follow-on question regarding WAC 480-100-620 posted 12 minutes ago? Thanks!
02:17:51 PM PDT	Doug Howell	To build off of what Elizabeth just said, and you "must" put in the social cost of carbon in the baseline assumption.
02:18:43 PM PDT	Fred Heutte	Just a thought -- we used GoToWebinar for a test run and the limitation of only "organizers" seeing the actual entries in the chat is a significant limitation, so you may want to consider GoToMeeting next time.
02:19:18 PM PDT	David Perk	But will the Social Cost of Carbon be part of the baseline assumptions?
02:19:52 PM PDT	Fred Heutte	Also to note -- I hosted a webinar on resource adequacy on Tuesday with GoToMeeting and the chat is a lot better with everyone seeing the interaction.
02:21:07 PM PDT	James Adcock	I don't feel it is fair to blame "technology" for the very limited amount of real and meaningful active "public participation" in this meeting. These kinds of "technology" related meeting problems have been going on for more than a decade now.
02:21:28 PM PDT	David Perk	+1 to Fred's comment on using GoToMeeting for better interaction and transparency.
02:22:32 PM PDT	Joni Bosh	How recent is the HDR data? My recollection is this study was completed in 2018?
02:25:55 PM PDT	James Adcock	I will ask my "NREL" question again: Can we get a pointer to the web address of the "NREL [Wind] database" mentioned on page 25 of this meeting?
02:26:02 PM PDT	Fred Heutte	I'm not understanding the 37.5-100 operating range for pumped storage. The Absaroka Gordon Butte project anticipates a full operating range from -400 to +400 with very little interruption and very fast (20MW/sec) ramp rates based on a European design with at least one plant in service using that configuration.
02:26:10 PM PDT	Doug Howell	What is winter peaking for Montana wind?
02:26:56 PM PDT	Kate Maracas	Section 13(3) of CETA requires Commerce and the UTC to adopt rules defining analysis and reporting requirements for "Retail electric load met with market purchases and the western energy imbalance market or other centralized market administered by a market operator" (among other things). How does the IRP evaluate the role of market resources (energy prices)? The generic resource cost data on PSE's website only includes capital and O&M costs.
02:26:59 PM PDT	Fred Heutte	Offshore wind is way above the indicated value for the "sweet spot" area from southern Oregon to northern California -- well above 50%.
02:28:54 PM PDT	Fred Heutte	Could you explain a bit more on using wind/solar P50 values for the resource adequacy assessment? Maybe I'm missing something but where a deterministic value may be ok for some modeling, for RA it really needs to represent daily, seasonal and interannual variability.
02:29:33 PM PDT	Robert Briggs	Please tell us where the offshore wind is located.

Time Asked	Name	Question Asked
02:31:34 PM PDT	Kevin Jones	If I heard Irena correctly, let me say, for the record, that PSE appears to not be implementing WAC 480-100-620 regarding public participation.
02:32:53 PM PDT	Kevin Jones	Regarding offshore wind - how far off the coast?
02:37:10 PM PDT	James Adcock	Thank you for the NREL ref -- can you also repeat the assumed Wind Turbine model number which is being used?
02:39:07 PM PDT	James Adcock	There are many different Wind Turbine models and blade designs matching "3 Megawatt 100 Meters" can you please give me more detailed technical information about what exactly you are assuming?
02:43:40 PM PDT	Doug Howell	Do gas costs include social cost of carbon and upstream emissions?
02:46:08 PM PDT	James Adcock	Why not include interconnect costs?
02:46:38 PM PDT	Don Marsh	I don't understand excluding the cost of interconnection. Does that get included somewhere else?
02:48:50 PM PDT	Kevin Jones	How does PSE evaluate the cost risk of having to move offshore wind more than 3 miles offshore in the IRP? Is this a revision to the model when you complete your research, or does the model include a cost variation parameter?
02:49:04 PM PDT	Mike Hopkins	for thermal generation, was there any consideration of using biofuels or renewable gas as fuel instead of traditional nat gas?
02:52:29 PM PDT	Fred Heutte	here's a number of comments compressed into one submission -- * thanks for an well structured breakout on new resource costs and for providing full detail - big progress already in the 2021 IRP! * we disagree very strongly with using AEO future cost curves, they are using an obsolete approach and the ATB method is much better * we recommend converting to discounted present value instead of nominal value, not only for generation costs but across the board in the IRP * future cost decline most important to get right for fast innovation resources including solar, battery, hybrid and offshore wind * very important to model hybrids (solar+storage, wind+storage) in this IRP!
02:52:57 PM PDT	Fred Heutte	sorry about the formatting on that one! I will also have a couple comments on the specific details when that's appropriate
02:53:15 PM PDT	James Adcock	I am concerned about the possibility of triggering large-scale gas pipeline upgrade needs without fairly including those costs in NG Peaker costs analysis.
02:54:23 PM PDT	Kevin Jones	Does the PSE model include cost risks in general? If not, how to you consider cost risks?

Time Asked	Name	Question Asked
02:54:49 PM PDT	Bill Pascoe	Where can we find information about assumed lives for the various resurces?
02:56:10 PM PDT	Don Marsh	+1 on Fred's recommendation to model hybrids (renewables + storage). We have seen costs of 2 cents / kWh for solar + storage in El Paso, TX. Might not be quite so cheap in the Northwest, but we would like to have accurate accounting of those technologies in our region.
02:56:16 PM PDT	Robert Briggs	There are two recent studies that show that renewable hydrogen can play an important role in enabling transitioning to 100% carbon-free energy at reduced cost. The two studies of great relevance to this IRP are: Path to 100% Renewables for California, WÄRTSILÄ®, <https://www.wartsila.com/docs/default-source/power-plants-documents/downloads/white-papers/americas/path-to-100-renewables-for-california.pdf>. Hydrogen Opportunities in a Low-Carbon Future: An assessment of long-term market potential for hydrogen in the Western United States, Energy+Enviromental Economics, May 2020. It seems that it would be financially imprudent for PSE to add any thermal plants that are not designed to allow them to operate on 100% hydrogen, otherwise they will be at risk of being taken out of service before the end of their service life. Your comment?
02:56:42 PM PDT	Doug Howell	How is PSE dealing with the risk of stranded assets for new gas plants given likelihood they will no longer be "used and useful" but the debt will continue?
02:58:08 PM PDT	Fred Heutte	question on solar+battery hybrid -- will you be using combo cost rather than adding one to the other?
02:59:43 PM PDT	Fred Heutte	We are seeing costs for combo solar+hybrid that are much less than adding them together for several reasons -- colocation costs and some factors that appear to relate to project finance and investor risk appetite
03:01:19 PM PDT	Kevin Jones	Has PSE looked at the available market for "alternate fuels"? Both capacity and cost?
03:01:50 PM PDT	Robert Briggs	Yes, purchase only equipment that can run on 100% hydrogen. Also, add renewable hyrdogen as a storage resource.
03:03:36 PM PDT	Valerie O’Halloran	I may have missed this, but will PSE be looking at HydroPower as well.
03:05:32 PM PDT	James Adcock	Again, under WA law it only "works" to use renewable fuel on NG plants IF you directly use that renewable fuel in the NG plant. If you simply inject renewable gas into the gas pipeline in general you are only qualifying for the "20%" part of the 2030 "80/20" requirements. And again, you have not yet clearly stated for the record whether: "Yes PSE will meet the 2030 '80/20' requirements" -- or alternatively

Time Asked	Name	Question Asked
		maybe PSE is saying: "We don't believe we have a requirement to meet 2030 '80/20' requirements" -- we need to understand what PSE's position is on this issue so that we can understand what PSE is trying to accomplish in this IRP.
03:05:40 PM PDT	Fred Heutte	Info on the Absaroka Gordon Butte project: https://gordonbuttepumpedstorage.com/wp-content/uploads/2020/03/3.04.2020_BriefingDoc_Final.pdf and their NW Council presentation https://nwcouncil.app.box.com/s/xfuiz4fzn0yw6zzmu61djsxc7pt5b3z7
03:06:36 PM PDT	Brian Grunkemeyer	Follow-up: should the value of energy produced in out years be reduced by the discount rate?
03:08:22 PM PDT	Bill Pascoe	When and how will PSE look at flexible capacity needs in this IRP?
03:10:05 PM PDT	Brian Grunkemeyer	If you apply a discount rate to the operating costs, but don't provide a discount rate to the value of energy produced, isn't that inconsistent?
03:10:50 PM PDT	Willard (Bill) Westre	The Variable costs do not seem to include fuel cost. Is this separate?
03:14:21 PM PDT	James Adcock	In previously IRP's there were concerns about required diesel start-ups on the Recips -- not able to meet air quality requirements?
03:16:15 PM PDT	Fred Heutte	On the specific details (referring to the XLS data, for which many thanks) -- * we recommend using only the most recent cost estimates per source for the "clean" averages, and removing previous estimates such as the earlier ATB and PSE IRP values * we also suggest completely excluding the ATB "constant" values which are only intended as a constant baseline for NREL internal modeling
03:18:03 PM PDT	Fred Heutte	One more on the details -- we recommend averaging the ATB low and mid values because they represent the lower and higher bound of their modeling and especially for solar we believe the average between ATB low and mid is the most likely case based on our own modeling
03:19:07 PM PDT	Court Olson	Utility solar doesn't have to be tracking. Have you compared the cost of non-tracking?
03:19:07 PM PDT	Fred Heutte	On offshore wind, there is significant new cost data showing much lower capital cost but it is still basically proprietary -- I will try and connect PSE to some sources
03:21:18 PM PDT	Fred Heutte	If I might respond to Court -- the vast majority of utility scale PV is now single axis tracking, with effectively no incremental capital cost but better overall output, especially with properly sized inverters (as measured for example by the inverter loading ratio or ILR)
03:31:58 PM PDT	Don Marsh	I still have a question about when we will discuss the Load Forecast.
03:33:49 PM PDT	Doug Howell	More than just stochastic modeling, we need input files for Aurora, Plexos, Resource Adequacy and Load Forecast

Time Asked	Name	Question Asked
03:34:18 PM PDT	Don Marsh	I'm disappointed that the Demand Forecast is designated as an "inform" item. This group has good questions and good information that could "inform" PSE's modeling. We are hoping the Demand Forecast will be much more accurate than it has in previous IRPs.
03:35:57 PM PDT	David Perk	+1 Don's comment re Demand Forecast's "inform" designation
03:36:33 PM PDT	Joni Bosh	I think the reference is to the current DR RFP and the all source RFP that is underway?
03:36:50 PM PDT	David Perk	+1 Doug's request for additional input files to be made available
03:38:38 PM PDT	Don Marsh	+1 Doug's request for input files
03:38:39 PM PDT	Joni Bosh	Yes.
03:40:18 PM PDT	Fred Heutte	if I understand correctly, you automatically get GoToMeeting with the GoToWebinar subscription
03:40:24 PM PDT	Kate Maracas	Can PSE provide anonymyzed bid data in the form of median values by project type?
03:40:45 PM PDT	Doug Howell	Why aren't questions made available to everyone?
03:41:03 PM PDT	Fred Heutte	we are all learning about this new all-webinar-all-the-time world!
03:41:14 PM PDT	Willard (Bill)Westre	How have the responses (PPA's) to the 2017 RFP's, indicating market costs effected the cost data.
03:41:31 PM PDT	Doug Howell	It is must different to see questions in real time.
03:41:39 PM PDT	Doug Howell	It is *much different
03:44:07 PM PDT	Don Marsh	We learn a lot from anonymized RFP data from utilities in other states. It would be wonderful if PSE took this step for increased transparency and accountability. It's appropriate for such a technologically and ecologically advanced region as the Puget Sound.
03:45:56 PM PDT	David Perk	Will there be a general public comment opportunity during the 2021 IRP cycle?
03:46:01 PM PDT	Brian Grunkemeyer	FYI - we saw a drop in EV driving (and charging) by about 75% as a result of COVID shelter-in-place and stay-at-home orders. I'll send some pictures for your information.
03:46:14 PM PDT	Kate Maracas	Will PSE consider using bid data to inform future IRPs once they have been fully negotiated? Note that I'm not suggesting making the data public.

Time Asked	Name	Question Asked
03:46:22 PM PDT	Bill Pascoe	Have the meeting times been established?
03:46:24 PM PDT	Kevin Jones	Do all these meetings start at 1:30PM?
03:46:30 PM PDT	Joni Bosh	Could you post the link to the website again:
03:47:48 PM PDT	Virginia Lohr	Didn't UTC (David Nightingale) ask for anonymous RFP data in one of the early 2029 IRP meetings?
03:48:20 PM PDT	Virginia Lohr	2019 IRP, I meant
03:48:30 PM PDT	Don Marsh	We have seen COVID impacts on electric demand from around the country, but very little information from the Northwest. When will PSE tell us what is happening in its service area?
03:51:09 PM PDT	Court Olson	In future meetings, would you please schedule a five minute "bio" break after 90 minutes?
03:51:15 PM PDT	Kevin Jones	Could you post your website link in the chat?
03:51:30 PM PDT	Kevin Jones	Sorry - I see you did. Thanks.
03:52:43 PM PDT	Kate Maracas	It's https://pse-irp.participate.online
03:56:15 PM PDT	David Perk	hank you -- wishing you good health

PSE IRP Feedback Report
Webinar 1: Generic Resources Assumptions
May 28, 2020

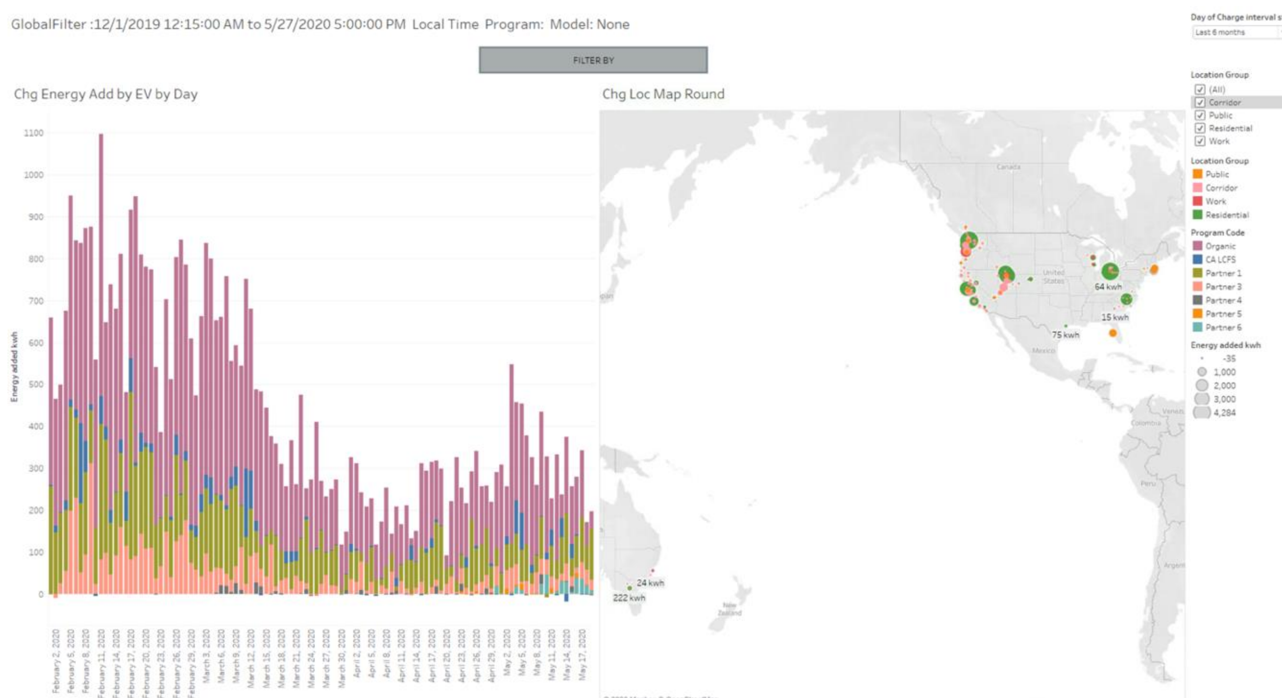
6/11/2020

The following stakeholder input was gathered through the online Feedback Form, from May 13 through June 4, 2020. PSE's response to the feedback can be found in the far-right column. To understand how PSE incorporated this feedback into the 2021 IRP, read the Consultation Update, which will be released on June 18, 2020.

2021 IRP Generic Resource Assumptions Workshop Feedback Report			
Feedback Form Date	**Stakeholder**	**Comment**	**PSE Response**
5/13/20	James Adcock	I am concerned that while I received an email "invite" to join the 2021 IRP process, when I tried to use the provided automated method of responding to that "invite" PSE's automated system instead logged an error message, rather than correctly "signing me up" for the IRP process. I then sent an email to PSE IRP leader Irena Netik, telling her about this problem, asking her to sign me up for the 2021 IRP, and asking her to acknowledge this email. She has not responded.	An acknowledgement email was sent on 5/13/20 at 2:20 pm. A copy of the message is included below: **From:** Netik, Irena **Sent:** Wednesday, May 13, 2020 2:20 PM **To:** 'jimad@msn.com' <jimad@msn.com> **Subject:** RE: Welcome to PSE's 2021 IRP Process Hello Jim, Thank you for your continued involvement and interest in the 2021 IRP process. I am confirming that we did in fact receive your response to the poll in the MailChimp email indicating that you do want to be engaged in the 2021 IRP process. Thank you for your feedback on the usability of that poll and we will work to make responding clearer. PSE is committed to engagement throughout the 2021 IRP process, and I appreciate interested stakeholders like yourself. I hope you are available to attend the first webinar on May 28, 2020 from 1:30 p.m. to 4:00 p.m. Thank you, Irena Netik Director, Resource Planning **From:** James Adcock <jimad@msn.com> **Sent:** Wednesday, May 13, 2020 6:15 AM **To:** IRP -- mail -- **Subject:** Re: Welcome to PSE's 2021 IRP Process **CAUTION - EXTERNAL EMAIL** Phishing? Click the PhishAlarm **"Report Phish"** button. For mobile - forward to **abuse@pse.com** Could you acknowledge this email please, so that I know you received it? Thank you,
5/21/20	James Adcock	This question relates to the May 28 2020 IRP Presentation, Page 25 -- -- "Operating characteristics" of Wind Resources. The source of this information is given as "NREL Database." Can you please give us a pointer to the exact "NREL Database" and information therein being used? IE a web address, etc.? As you know, in recent years the Wind Industry has advanced their technology, both in designing new windfoils with greater availability at lower wind speeds, which might benefit "Washington Wind Annual Average Capacity Factor" and also in improving power conversion, such that high wind generation limits have been lifted, so that more power can be generated in high-wind conditions. I want to make sure that your data source "NREL Database" is recent enough to capture these new Wind technological developments. Please answer the question asked so that we can determine whether or not your modeling assumptions include recent Wind Industry innovations that may affect resource costs, and relative resource costs, including affecting whether Wind resources are better built in Washington vs. Other States.	The NREL database refers to the 5-min wind speed data obtained from NREL's Wind Toolkit database: https://www.nrel.gov/grid/wind-toolkit.html. The NREL Wind Toolkit data contains mesoscale modeled data from 2007 to 2013. Only wind speed data was used from the NREL database, capacity factors were calculated by PSE analysts with experience in wind energy assessment in order to employ up-to-date wind technology and methods. The raw, 100m above ground level wind speed data was processed using industry-informed methods to calculate hourly net production shapes. Processing steps include: • Re-average 5-min wind speed data to hourly wind speed data • Calculate gross production using the air density adjusted, power curve for a GE3.03-140 as a model turbine • Apply loss factors including estimated wake impacts, stochastic availability losses, turbine performance losses, environmental losses (stochastic icing shutdown, high/low temperature shutdown) and electrical line losses to calculate a final net production shape. • Validate net production calculation against existing NREL Wind Tool Kit net capacity factor estimates and DNV GL production calculations for select sites.

			This process was repeated for 250 unique locations surrounding the point of interest, then the most representative shape was selected for the deterministic Portfolio model. The described process has only been performed for the wind resources added to the 2021 IRP (Wyoming and Idaho wind resources). 2019 IRP wind resource characteristics (Washington, Montana, Offshore) were obtained from HDR and DNV GL 3rd party analysis. The HDR report is available for review on the PSE IRP website (pse.com/irp). Documentation for the DNV GL wind shapes is not available at this time.
5/28/20	Brian Grunkemeyer, FlexCharging	When evaluating resources, do you apply a discount rate to the value of energy produced? This article below in Utility Dive makes an argument that the Levelized Cost of Energy hurts renewables because the math is wrong. The author observes that LCOE doesn't apply a discount rate to the value of energy produced in the out years. The claim is LCOE overprices wind & solar by 18% and 27% respectively compared to natural gas. The author is pushing a slightly corrected metric, the “present value of the cost of energy” instead of LCOE. https://www.utilitydive.com/news/lcoe-is-not-the-metric-you-think-it-is/578360/ It's possible PSE doesn't use LCOE at all in its resource evaluation. But it may be useful to understand whether discount rates apply to the value of energy produced as well as operating costs. This same thought process could apply to conservation as well, correct? Please inform the IRPAG about whether it is reasonable to apply a discount rate to the value of energy when valuing resources & conservation measures, and whether you do so.	Resources are evaluating on an annual basis for the life of the plant, we do not use the levelized cost of energy in the models. The discount rate is only applied at the end to levelize the costs for charts and tables that are used for comparison.
5/28/20	Virginia Lohr, Citizens' Climate Lobby	The emails I received before the May 28 meeting had links to this form and to a general PSE IRP page, but the link to the specific page where the materials for the webinar would be was not included. I had to send time searching through your IRP pages to find them. In the future, I suggest you send copies of the materials for a webinar to all people who have expressed interest in the IRP process. If that is not possible, then at least share the url of the actual web page where you are posting the materials.	Thank you for the suggestion. PSE will plan to send direct links to materials in future email updates.
5/28/20	James Adcock	This is feedback in regards to the chosen PSE "technology" for the meeting, namely "GoToWebinar" and the need to submit questions indirectly by keyboard as opposed to directly by microphone. I have participated in other large meetings including by Commerce and UTC which did successfully allow direct communication and interaction with the presenters by microphone. By using the "raise hand first" protocol this worked out very well in these other forums. But, in regards to today's "GoToWebinar" format where one has to type in questions via keyboard -- it really didn't work for me. What I see happening in practice over and over again is that Irena or Elizabeth interpret a question not as coming from an technological expert, but rather as-if it were coming from a kindergartener, and then give either a dismissive answer, or no-answer-at-all but rather an answer to a different question that the presenter made up in their mind. For example often a technology expert participant asks a question -- in context -- "But what about ABC?" and Elisabeth simply answers a different question "As I told you earlier, we are not doing ABC, we are doing XYZ." OK, but the participant didn't misunderstand what you were doing [which was XYZ], rather they asked you a specific question, which you chose to ignore by answering an entirely different question. And the problem with having to use a keyboard and chat -- as PSE knows perfectly well -- is that gives no opportunity for the technology expert participant to say "Wait a second -- that is not the question I asked you!" In summary "GoToWebinar" is simply yet-another PSE ploy, in a long series of PSE ploys, over a decade-plus of IRP meetings, to prevent real and meaningful public participation, allowing the public to actually ask real and meaningful technological questions, and receiving real and meaningful technological answers. The reason that these question are being asked is very simple: Participants want to be able to ensure that PSE is making the best resource acquisitions -- and retirements -- possible, at BOTH the lowest ratepayers costs AND the lowest environmental damage costs. And the reason the PSE continually avoids giving meaningful answers is that PSE does not want to be held accountable to actually making the best possible resource acquisitions -- meaning that PSE will be making resource acquisitions which are more expensive to ratepayers, AND more damaging to the environment.	For the June 10, 2020 meeting, PSE transferred the meeting platform from GoToWebinar to GoToMeeting in part due to your and other participants’ feedback. PSE will make best efforts to more clearly answer questions in all meetings.

		PSE, like Commerce and WUTC already do, needs to choose to use a "technological resource" that allows participants to ask questions of presenters by microphone "in more-or-less real time" after the participant "raises their hand". Further, PSE presenters should commit to giving real and meaningful answers to participant questions, which actually are responsive to the question, and not simply dismissive ploys just intended to "make the question go away." PSE needs to actually make a real commitment to PUBLIC PARTICIPATION in their IRP Process -- as required by law -- and not this continual PSE ploy of "We Talk and You Just Listen." PSE needs to design into meeting schedules enough time for participants to ask questions. I suggest that PSE design into their meetings the assumption that 1/2 of the time will be taken by PSE making presentations, and that 1/2 of the time will be used by participants asking questions and by PSE giving actual and real answers to those questions, rather than engaging in ploys to avoid given real answers.	
5/28/20	James Adcock	This is feedback you requested in terms of a more detailed understanding of what exact NREL Wind Data you are using, and what "generic 3 Meg 100 Meter" wind turbine you are assuming. My expressed concern is that your modeling may not include more recent Wind Turbine technological developments over recent years, where now wider blades are available making Wind Farms display better availability at lower wind speeds -- as may be more appropriate to Washington State Wind Farm modeling, and also higher output generators are now available which do not run into output upper limits until higher wind speeds -- which may be more appropriate for Montana Wind Farm modeling. Can you please tell me exactly what you are using in terms of Wind Turbine assumptions. What I see on the NREL site is the assumption of "Vestas V-90 3 MW" -- is this the wind turbine you are assuming for all your Wind Farm modeling? What I also see on the NREL site is various documentation and data creation dates from 2007 to 2015 -- meaning that any Wind Turbine technological developments in the last 5 to 13 years would not be included in your IRP modeling. Is this a correct assumption? Please clarify to me and other participants exactly what NREL wind data you are using and how, exactly that Wind Turbine(s) you are modeling, and from what calendar year your wind data, and wind turbine model(s) date from.	The NREL database refers to the 5-min wind speed data obtained from NREL's Wind Toolkit database: https://www.nrel.gov/grid/wind-toolkit.html. The NREL Wind Toolkit data contains mesoscale modeled data from 2007 to 2013. Only wind speed data was used from the NREL database, capacity factors were calculated by PSE analysts with experience in wind energy assessment in order to employ up-to-date wind technology and methods. The raw, 100m above ground level wind speed data was processed using industry-informed methods to calculate hourly net production shapes. Processing steps include: • Re-average 5-min wind speed data to hourly wind speed data • Calculate gross production using the air density adjusted, power curve for a GE3.03-140 as a model turbine • Apply loss factors including estimated wake impacts, stochastic availability losses, turbine performance losses, environmental losses (stochastic icing shutdown, high/low temperature shutdown) and electrical line losses to calculate a final net production shape. • Validate net production calculation against existing NREL Wind Tool Kit net capacity factor estimates and DNV GL production calculations for select sites. This process was repeated for 250 unique locations surrounding the point of interest, then the most representative shape was selected for the deterministic Portfolio model. The described process has only been performed for the wind resources added to the 2021 IRP (Wyoming and Idaho wind resources). 2019 IRP wind resource characteristics (Washington, Montana, Offshore) were obtained from HDR and DNV GL 3rd party analysis. The HDR report is available for review on the PSE IRP website. Documentation for the DNV GL wind shapes is not available at this time.
5/28/20	Nate Sandvig, National Grid Ventures	-This comment is in reference to slides 43 and 44- PSE IRP Team, Good webinar. Reviewing pumped storage slide/assumptions, would change Swan Lake COD to 2026. Would also add 1200-MW Goldendale and a COD of 2028. We have HDR as our quasi-owner's engineer for Goldendale, and they can follow-up with details (Carl Mannheim with HDR is copied). Presumably with scale in mind, Goldendale should be less capital cost on a $/kW basis. Also, by averaging data sources, Swan Lake (and Goldendale) is really at a disadvantage compared to batteries when that is not necessarily the case. As you've stated, pumped storage went up (2176→2515) and batteries went down (2427→1900). Just trying to keep a level playing field on cost for starters without getting into duration advantage, supply chain risk, degradation, recycling, waste, etc. that aren't factored into battery costs.	PSE is currently researching more information on pumped storage hydro and will have the results for the Consultation Update on June 18. PSE contacted Nate Sandvig on June 11 and discussed more detailed information on the Swan Lake and Goldendale projects. We look forward to receiving this information and incorporating it into the analysis.

		Thanks, Nate Sandvig	
5/28/20	Brian Grunkemeyer, FlexCharging	During today's IRPAG meeting, someone mentioned PSE was still working to understand demand changes after the impact of SARS-CoV-2. At FlexCharging, we do have a number of electric vehicles that we're monitoring, and we saw a ~75% drop in driving & charging. California issued a shelter-in-place order around March 15. WA high tech employers encouraged everyone to work from home around March 5th, then Gov. Inslee issued a stay-at-home order late the following week. This data is not limited to the US west coast. I've also included a map of the charging locations here. The number of charge sessions at public, workplace, and corridor chargers also dropped after the lockdowns. But it also looks like drivers got antsy in the first week of May. 	This information has been shared with PSE's load forecasting group and will be discussed further at the demand forecast meeting which will be scheduled in the next few weeks.
5/29/20	Don Marsh, CENSE	I participated in the Generic Resource Assumptions webinar on May 28. At a couple of points during the meeting, I asked questions about the Demand Forecast, but the answers were vague and unsatisfying. First, I asked when the Demand Forecast would be discussed. No specific date was given. PSE said the company was trying to evaluate the impacts of the COVID-19 crisis. Of course, we all understand the pandemic is having a significant negative effect on demand. However, PSE has a process for handling uncertain scenarios (like the future price of natural gas). The company can provide a range of outcomes (best case, worst case, and most likely), and then we can proceed cautiously with those scenarios in mind. Second, I asked how the public could participate in the development of the forecast. I was told that this part of the IRP would be "inform-only." This means that PSE will do all of its modeling in secret, and then "inform" us what the models predict. Without access to the data or the tools, we must trust PSE to come up with the right answers. However, this trust has been strained because PSE's forecasts have been significantly too high during the last decade, occasioning comment from the WUTC. For example, in previous IRPs, PSE has consistently projected substantial demand growth during the winter, but winter demand throughout PSE's service territory has actually declined since 2009. The Demand Forecast is at least as important to a successful IRP as the Generic Resource Assumptions. If the public doesn't have a good understanding of what customers' future needs will be, it's hard to know whether the IRP is a prudent plan to meet those needs. We should understand where there are likely to be "hot spots" of demand growth, and how vigorous that growth is expected to be. A forecast that covers PSE's entire service territory misses opportunities to target local needs with appropriate alternatives. For example,	The demand forecast for the 2021 IRP will be covered in an upcoming meeting. PSE is currently developing a schedule for the next set of meetings. We expect the website (pse.com/irp) to be updated and a schedule filed with the WUTC in the next few weeks.

		high growth in a small area might be an ideal scenario to deploy distributed resources and energy storage without over-building the entire grid. PSE's "Energize Eastside" project provides an instructive example. The company is using a five-year-old forecast of 2.4% annual demand growth to justify this project. Given the history of demand during the past decade, plus the realities of lower demand in the COVID age, this forecast is pure fantasy. Even before the outbreak of the virus, 2.4% growth seemed incongruous given falling winter demand throughout PSE's service area. PSE responded that the growth of the Eastside is unprecedented and is straining the Eastside grid. However, no proof has been provided that Eastside population and economic growth is actually producing increased demand, or that Eastside growth is significantly more vigorous than other areas served by the utility. Ratepayers worry that incorrect forecasts are used to justify unnecessary infrastructure investments that are costly to customers and harmful to the environment. We request four corrective steps be taken immediately: 1) Schedule a meeting specifically dedicated to the Demand Forecast. This meeting should occur as soon as possible, because the rest of the IRP is difficult to judge if participants don't have a clear understanding of the need PSE is trying to serve. 2) Provide individual summer and winter forecasts for each of the eight counties served by PSE (or finer geographic granularity, if warranted). 3) Provide full data and assumptions to IRP participants, and allow substantive feedback to shape the final forecasts. 4) To provide full context, demand forecasts should show at least ten years of peak demand history, including both actual and weather normalized trends. We also need to have a discussion about weather normalization procedures. There is no reason why this fundamental part of the IRP should remain secretive and obscure. To be legitimate, this IRP must demonstrate a significant improvement in the process and transparency of the Demand Forecast. Sincerely, Don Marsh	
6/1/20	Robert Briggs, Vashon Climate Action Group	There are two recent studies that show that renewable hydrogen can play an important role in enabling transitioning to 100% carbon-free energy at reduced cost. The two studies of great relevance to this IRP are: Path to 100% Renewables for California, WÄRTSILÄ®, https://www.wartsila.com/docs/default-source/power-plants-documents/downloads/white-papers/americas/path-to-100-renewables-for-california.pdf. And Hydrogen Opportunities in a Low-Carbon Future: An assessment of long-term market potential for hydrogen in the Western United States, Energy+Enviromental Economics, May 2020. [See Attached Executive Summary] It seems that it would be financially imprudent for PSE to add any thermal plants that are not designed to allow them to operate on 100% hydrogen, otherwise they will be at risk of being taken out of service before the end of their service life. Your comment?	Thank you for the reference material. We have reviewed through the Wartsila slides and are working on reviewing through the other documents that you have provided. The PSE IRP team has also scheduled a meeting with an industry expert to learn more about the commercial availability of renewable fuels for gas plants. PSE is currently researching more information on this topic and will have an update for the Consultation Update on June 18.
6/1/2020	Robert Briggs, Vashon Climate Action Group	Include electrolyzers and compressed hydrogen storage used in conjunction with H2-capable peaker plants as a measure in this IRP. Install a small (e.g., 5 MW) electrolyzer at one of your gas plants to evaluate its potential for long-term storage and the provision of other grid services.	The PSE IRP team has been in contact with the plant engineers to discuss this recommendation. The team is currently researching hydrogen as a fuel at the current gas plants and future gas plants and will have an update for the Consultation Update on June 18.
6/2/2020	Kevin Jones, Vashon Climate Action Group	REVISED: I participated in the 2021 PSE IRP Generic Resource Assumptions webinar on May 28, 2020. There are at least two concerns that I would like PSE to respond to.	Thank you for your questions. Responses below as you have numbered and labeled: 1. There are different risk factors when looking at new assets.

		1. It appears that PSE is not considering cost risk of potential assets being analyzed in the 2021 IRP. In some cases, the siting of offshore wind assets or the market cost of non-fossil based gas fuels, for example, these cost risks could be considerable. Yet it was clearly stated in the presentation that PSE does not consider asset cost risk in the IRP analysis. a. Why is cost risk not considered in the PSE IRP analysis? b. Where in the PSE portfolio analysis process is cost risk considered? c. Please also address how PSE's analysis process considers, or does not consider, asset acquisition schedule risk. 2. The IRP Draft WAC 480-100-620 states that "The utility must inform, consult and involve stakeholders in the development of its integrated resource plan and its two-year progress report" (emphasis added). When asked "What IAP2 level are you applying to this meeting?" Irena Netik responded "we are applying the consult level to this meeting" (ref time 31:33 in the meeting recording at https://register.gotowebinar.com/recording/3604364449812524812). When asked "Since WAC 480-100-620 uses "and", not "or", wouldn't it be more appropriate to apply the "involve" level of public participation to this meeting? If not, why not?" Irena Netik's answer was "PSE made the determination that we use involve as the appropriate level" (ref time 49:30 in the meeting recording at https://register.gotowebinar.com/recording/3604364449812524812) a. Please clarify PSE's position – will the May 28, 2020 meeting comply with the consult or involve IAP2 level? b. Please provide rationale for not conducting all 2021 PSE IRP meetings at the IAP2 "involve" level of public participation given the use of the word "and" in WAC 480-100-620 public participation directions. Please let me know where and when we can expect a reply. Please provide and post answers to the above questions on the PSE IRP website. Thank you, Kevin Jones kevinjonvash@gmail.com Vashon Climate Action Group	a. The risk of permitting. This is a factor used when assessing resources in the RFP, but not included in the IRP. b. The risk that resources will have different costs than projected. In the past PSE has not modeled this risk as part of the stochastic risk modeling, but we have discussed it several times and started developing information for the 2019 IRP. PSE will work to use a cost of resource as one of the variables to change in the stochastic analysis. The stochastic analysis work will begin later in the year. c. Asset acquisition schedule risk. This risk considers the operating start date for different resources. Since the 2021 IRP planning horizon starts in 2022, PSE considers the schedule for asset acquisition, permitting and building for the first year a resource is available. For example, a wind project can be built in 18 months, but you also have to consider permitting, acquisition of the turbines, and transportation to the side. This increases the process to 3 years lead time, so the first year available is 2024. 2. PSE reviewed stakeholder input from 2019 and considered the levels from the IAP2 spectrum that could be best supported. PSE determines the IAP2 spectrum for the public participation. The meeting on May 28 was at the "consult" level which is defined by IAP2 guidelines as "to obtain public feedback on analysis, alternatives and/or decision" and the promise is to "keep you informed, listen to and acknowledge concerns and aspirations, and provided feedback on how public input influenced the decision." Certain IRP subjects will be at the "involve" level but not all subjects meet that level of involvement.
6/3/2020	Willard (Bill) Westre, Union of Concerned Scientists	The Generic Resource Approach is no longer a reasonable method of analyzing generation costs for an IRP or a CEIP. It does not reflect the way PSE acquires resources so it cannot be accurate or transparent. Of the 97 responses to PSE's 2017 RFP's, the vast majority of generation resources proposed were Power Purchase Agreements (PPA). Of the 21 responses selected by PSE for further consideration 18 were PPA's for direct delivery of power at a defined price, only one was a PPA with a build-asset option and only two were PPA's with a buy-asset-option. The Generic Resource Approach data as presented leaves out the majority of generation resource costs – particularly finance cost, fuel cost, accurate performance data, national state and local subsidies, property and other ownership costs; local variations such as tax and labor rates, grandfathered requirements and other competitive advantages, construction transportation costs, etc. that are inherently included in PPA proposed costs. PPA proposals are a considerably more accurate source of data to use as the foundation for resource selection. Since PPA data is what PSE uses in resource selection, it is the data that should be used in the IRP including subsequent analysis processes such as resource adequacy. Adopt a Market Cost Approach using PPA data from previous solicitations. Confidential data can be protected in numerous ways e.g. presenting average data for 3 or more PPA proposals of the same type. This has been used by other utilities that have adopted this approach. PSE could begin by using data from the 2017 RFP responses received in 2018. The data is available already – just use it. Use of 6.97% as discount rates in General Resource Assumptions is unwarranted. The current Federal Fund Rate is 0.25% with the possibility of going negative. The current 30-year Corporate Bond Rate is 3.24%. It is not prudent for PSE to charge ratepayers any higher than market rates for asset purchases or use in determining capital costs for future assets. Secondly, use of high discount rates for cost estimates discriminates against renewable energy sources versus thermal resources - because renewable resources have high capital costs and zero fuel costs, whereas thermal resources have high fuel costs and lower capital costs.	The IRP models PSE-built resources as the generic resource, so a PPA is not directly comparable. PPAs are bids from third party developers and their financial structure is different from a utility, so they can offer prices that may be different from the cost for a utility to build and operate a generating resource. The generic resource cost webinar only presented the overnight costs. The Consultation Update will have the final costs that include the financing costs, PTC and ITC, taxes and insurance. PSE will continue to model generic resources as a PSE built and operated power plant. We can document the cost of materials and construction for a generic resources, but it is difficult to estimate future PPA costs, making it hard to model as a generic resource.

		Use the discount rate of 2% as suggested by the US Council of Economic Advisors in this policy brief: https://obamawhitehouse.archives.gov/sites/default/files/page/files/201701_cea_discounting_issue_brief.pdf Note: this does not apply to the discount rate specified for determination of the Social Cost of Carbon in the CETA regulation.	
6/4/2020	Bill Pascoe, Absaroka Energy and Pascoe Consulting	1. Pumped Storage Hydro (PSH) Nameplate Capacity (slide 24 from May 28, 2020 presentation) - The slide shows a 300 MW nameplate capacity. Please confirm that PSE will model shared ownership of a 300 MW PSH facility (PSE ownership share of less than 300 MW, say in 50 or 100 MW increments) in the IRP. 2. PSH Energy Storage Capability (slide 24) – The slide show an 8-hour discharge period, presumably at full (nameplate) capacity. Please confirm that this will be modeled in the IRP as 2,400 MWH of storage that can be called upon in various combinations of MW and hours (300 MW for 8 hours, 150 MW for 16 hours, 300 MW for 4 hours + 100 MW for 12 hours, etc.). 3. Energy Storage Recharge Parameters – What are the assumed recharge parameters for PSH and batteries? 4. PSH Operating Range (slide 24) – Gordon Butte PSH includes “quaternary” technology that allows the project to operate at any point from 0% to 100% generation and 0% to 100% pumping. This operating range should be modeled as a PSH option in the IRP. 5. Battery Degradation (slide 24) – The assumption that battery degradation is “near zero” is only reasonable if the capital costs on slide 44 include an allowance for future additions of new capacity to offset degradation of the initial installed capacity. If this is not the case, PSE should research and include a non-near-zero degradation rate for batteries. 6. Energy Storage Lives – What are the assumed lives for PSH and batteries?	PSE is currently researching more information on pumped storage hydro and will have the results for the Consultation Update on June 18.
6/4/2020	Stephanie Chase, Public Counsel Unit of the Washington State Attorney General’s Office	During the last webinar, PSE staff mentioned that there would not be a general public listening session for this IRP. In light of that, what efforts are you making to inform customers or stakeholders about the IRP process and ways that they may become involved or offer feedback, outside of the technical webinars?	For the 2021 IRP, PSE expanded its outreach efforts and contacted more than 1,400 potential stakeholders from across PSE’s service territory with an invitation to participate. As a result, new stakeholders have participated in the webinars. PSE continues to provide regular outreach and updates to the expanded stakeholder list. PSE is creating more stakeholder engagement opportunities through webinar recordings and feedback forms all through the process. Stakeholders can provide feedback to PSE at any point through the IRP process.
6/4/2020	Sarah Laycock, Public Counsel Unit of the Washington State Attorney General’s Office	There had been a question regarding renewable gas. As a follow up, just wondering if and how RNG will be modeled in this IRP. I saw that PSE contracted to obtain a certain (seemingly large?) amount from Klickitat PUD for about three years, if I recall correctly. So, just trying to figure out why RNG doesn’t appear to be listed as a renewable to model	PSE is currently researching more information on renewable fuels as an alternative fuel source and will have the results for the Consultation Update on June 18.
6/4/2020	Mike Hopkins, FortisBC	I think it would be useful to explore use of other fuels besides traditional natural gas in the thermal generation resource options - such as biofuels, renewable nat gas, hydrogen - to see if any would be viable in the future. While these fuels are likely more costly, they would reduce GHG emissions in valuable baseload or peaking plants. I think using the chat box to ask questions rather than having participants calling in was useful in keeping the meeting focused on the agenda topics and it was much easier to hear all the questions and answers.	PSE is currently researching more information on renewable fuels as an alternative fuel source and will have the results for the Consultation Update on June 18.
6/4/2020	Kathi Scanlan, WUTC, and WUTC staff	Commission Staff Feedback for Puget Sound Energy 2021 IRP: Webinar # 1 Generic Resource Assumptions (May 28, 2020) 1. This feedback, dated June 4, 2020, states the informal comments, questions, and recommendations of Washington Utilities and Transportation Commission Staff, Kathi Scanlan. Staff appreciates the continued work of PSE’s IRP Team and the opportunity to participate. Timely feedback is offered as technical assistance and is not intended as legal advice. Staff reserves the right to	1. Thank you and noted. 2. PSE will provide an updated table in the Consultation Update on June 18. 3. Transmission costs will be covered in the June 30 webinar.

		amend these opinions should circumstances change or additional information be brought to our attention and are not binding on the commission. 2. Capital Costs—Beyond slides 34 and 35, staff requests more information on definitions used by PSE, including definition of overnight capital costs, capital cost, or all-in capital costs to build plant. It is staff's understanding the Northwest Power and Conservation Council capital cost estimates include EPC + owners costs, including interconnection costs, development costs, legal, land, and overnight costs do not include interest that would be incurred during construction (AFUDC). Defining these new columns in the slides presented for the PSE recommended costs, including differentiating overnight capital, capital, capital-all-in, etc., for slides 36-45, and providing additional discussion and rationale is requested. 3. Conceptual cost estimates for transmission and delivery for each technology—the Clean Energy Transformation Act (CETA), including provisions in the IRP statute (RCW 19.280.030(1)(d)), which requires each utility to perform a comparative evaluation of renewable and nonrenewable generating resources, including transmission and distribution delivery costs. PSE indicated public sources do not identify different capital cost by region, so one cost will be used for each onshore wind option and transmission costs will vary depending on location. PSE responded that it may utilize the, "HDR Report flat 5-mile transmission and gas pipeline to get to system, plus flat $/mile applied to resources." Staff requests more follow-up information related to estimating costs for infrastructure outside the fence. PSE states, by June 18, PSE will decide what costs to use (slide 48). Staff requests clarification on transmission and distribution delivery costs, and when they will be discussed. 4. Regarding request for proposals (RFPs) and generic resource cost assumptions, staff asks: Can recent RFPs help PSE true-up resource costs in the IRP? The PSE's 2021 IRP resource cost inputs need to be the best available as they are a stand-in for potential new resources—there is a connection with the RFP. RFP data can inform generic resource costs, while maintaining confidentiality, where and when appropriate. How will PSE's RFP data inform generic resource costs? Staff agrees with comments posed by several other stakeholders on this discussion topic and requests PSE provide additional clarification of how its RFP data can inform cost data in its 2021 IRP. 5. Energy Storage—PSE asks stakeholders if the company should use the HDR Report for other battery options or only model the 4-hr Li-Ion in the IRP? Staff recommends PSE should include other battery options in its IRP analysis. By analyzing only one type, PSE is likely limiting its capacity for future resources from the outset and may not give PSE a broad enough analysis of how different resources can fit into PSE's needs. Energy storage is a key enabling technology for utilities to accomplish the goals of the state's clean energy transformation. In 2017, the Commission issued a report and policy statement on the treatment of energy storage technologies in the integrated resource planning process (see Docket U-161024, Service Date 10/11/17), which staff strongly encourages PSE revisit. Further, staff recommends PSE compare alternative data, including PNNL's Energy Storage Technology and Cost Characterization Report (July 2019): https://www.energy.gov/sites/prod/files/2019/07/f65/Storage%20Cost%20and%20Performance%20Characterization%20Report_Final.pdf This report defines and evaluates cost and performance parameters of six battery energy storage technologies (BESS) (lithium-ion batteries, lead-acid batteries, redox flow batteries, sodium-sulfur batteries, sodium metal halide batteries, and zinc-hybrid cathode batteries) and four non-BESS storage technologies (pumped storage hydropower, flywheels, compressed air energy storage, and ultracapacitors). Data for combustion turbines are also presented. Detailed cost and performance estimates were presented for 2018 and projected out to 2025. 6. Solar—According to a new LBNL utility scale PV benchmarking report (June 2020), solar useful life expectations have substantially increased to 30 years or more. The report includes relevant operation expenditure data: https://emp.lbl.gov/publications/benchmarking-utility-scale-pv. As reported by LBNL, solar project developers, sponsors, long-term owners, and consultants have increased project-life assumptions over time, from an average of ~21.5 years in 2007 to ~32.5 years in 2019. PSE's HDR Report (and workbook) provides data 5 to 10 years less than. Also, staff appreciates the additional consideration and data and analysis for distributed-generation residential solar (slide 39). Did PSE consider commercial distributed-generation solar as a type to model for its electric generic resource assumptions? 7. Existing and Refurbishment of Resources (remaining useful life)—Staff requests additional details regarding how PSE models existing resources and refurbishment costs and echoes similar questions raised in real time during the webinar on this topic. Please explain how PSE determines budgets for O&M inputs and economic retirement in the IRP modeling process. Further, how is PSE modeling PPAs—existing PURPA and other supply resources (expiration)? 8. For the 2021 IRP, PSE expanded its data sources and revised its generic resource assumptions based on feedback received from stakeholders from the last IRP cycle, which staff also appreciates. For the 2021 IRP, PSE states that it intends to utilize	4. For the 2021 IRP, PSE is following stakeholder recommendations to utilize publicly available cost information and will not utilize confidential bid information from the last RFP process. 5. PSE is researching the PNNL report and will have an update in the Consultation Update on June 18. 6. PSE is researching operating life and will have an update in the Consultative Update on June 18. 7. The operations and maintenance costs at PSE's existing resources are based on the most current budget and escalated at 1.5% per year. The PSE IRP team plans to use the 2020 budget for the 2021 IRP portfolio model. Since the IRP model allows for economic retirements, a decommissioning cost is used to adjust the remaining revenue requirement at the plant if it retires before the end of its economic life. All contracts are modeled with the contractual end date. The one exception is the Mid-C hydro contracts. The IRP has an assumption that the Mid-C contracts will get renegotiated and extended. The assumption for the Mid-C contracts in the 2021 IRP is under review. 8. The HDR report referenced in the webinar was incorrectly posted to the "Work Plan" area of the IRP website. The HDR report is now correctly posted with the Generic Resource Cost webinar materials. 9. A meeting for natural gas portfolio modeling has not yet been scheduled. PSE is currently developing a schedule for the next set of meetings. We expect the website (www.pse.com/irp) to be updated and a schedule filed with the WUTC in the next few weeks. 10. The GoToWebinar does not have the capability for attendees to make their questions visible to all GoToWebinar participants. Unfortunately, PSE learned about this limiting capability a few days before the webinar. The PSE team found a workaround to make all questions/comments visible to participants in real-time by copying and pasting the questions. PSE plans to us the GoToMeeting platform for the next webinar which has the desired functionality. 11. The demand forecast will be covered in an upcoming meeting. PSE is currently developing a schedule for the next set of meetings. We expect the website (www.pse.com/irp) to be updated and a schedule filed with the WUTC in the next few weeks. 12. PSE plans to share the appropriate model data as it is developed to support the IRP process. PSE is currently developing a schedule for the next set of meetings, which will include flexibility modeling and ELCC contributions. We expect the website (www.pse.com/irp) to be updated and a schedule filed with the WUTC in the next few weeks. PSE is researching efficiency gains for hybrid or co-located projects and will have an update in the Consultation Update. 13. PSE is tracking Northwest Power and Conservation Council's climate change analysis and at this time the IRP team is still assessing the appropriate methods to incorporate a climate sensitivity in the 2021 IRP.

		select information from the “Generic Resource Costs for Integrated Resource Planning, Revision 4” report authored by consultant HDR to supplement information. The generic resource costs will be derived from publicly available data sources and stakeholder feedback, where public data sources do not provide detailed operational characteristics necessary for robust power system modeling. The generic resource operational characteristics will continue to be sourced from the HDR Report. As such, staff questions why PSE’s Revision 4 Generic Resource Costs for IRPs (HDR Report), which was referenced numerous times in the webinar, was not initially posted under the first webinar and grouped with other Generic Resource Assumption Documents for review prior to the meeting. PSE’s website shows generic resource assumptions will be discussed on May 28, 2020 and lists four meeting documents: Webinar 1: Generic Resource Assumptions presentation REVISED [PDF, 1.6 MB] Webinar 1: Generic Resource Assumptions agenda [PDF, 120 KB] Generic Resource Assumptions Workbook Summary [Excel, 879 KB] Generic Resource Assumptions Webinar Q&A Log [PDF, 158 kb] PSE instead provides a link to its HDR Report under the subheading “Work Plan” in a completely different area of the IRP website https://pse-irp.participate.online/2021-IRP . To ensure transparency in the public process, staff recommends relevant documents be grouped or linked together with the relevant webinars to allow for timely stakeholder review before and after the meeting. 9. Slide 14—PSE made comments regarding the action plan not pertaining to the gas IRP (referring to step 6 of PSE’s 6-step process), please clarify if PSE intends to submit a short-term plan outlining the specific actions to be taken by the utility in implementing the gas long-range integrated resource plan? 10. Public Participation— Staff appreciates that PSE’s IRP webinar web recording is available for stakeholders and others who are not able to attend the webinar during work hours. Consultations with commission staff and public participation are essential to the development of an effective IRP. The PSE copy/paste delay of comments and questions in Webinar #1 was perplexing. Looking ahead, as PSE transitions to the new platform for Webinar #2, staff requests to see questions and comments from stakeholders in real-time during future webinars. 11. Upcoming Webinar #2—Staff found PSE’s comments regarding load forecasting as categorized as an “inform item” with no firm advisory group date around this topic surprising and requests further clarification and discussion. The demand forecast produced by PSE provides public insight into the future demand for power and gas in PSE’s service area. The demand forecast is influenced by economic and population trends in the Pacific Northwest. As a forecast, and an input for hourly demand for PSE, it is the most important factor in determining resource need. Again, staff believes ongoing feedback is essential to the development of an effective IRP. 12. Increasing Transparency in IRP Modeling—Staff appreciates PSE updates to the new website content, including delineating models used and inputs throughout the six-step IRP development process. The new generic resource assumptions workbook is a very helpful first addition to the library of data inputs and encourages PSE to share Aurora data input files and tables to increase transparency, including but not limited to Plexos Electric Portfolio Model, Electric Resource Adequacy Model (RAM), and Sendout Gas Portfolio, and other models. In terms of specific model questions, how does PSE account for efficiency gains for hybrids or co-located projects as inputs into the model(s)? Further, please specify the date PSE intends to discuss flexibility modeling and ELCC contribution? 13. Planning for tomorrow, the Northwest Power and Conservation Council is likely incorporating the impact of climate change in its next Power Plan. Reviewing regional and electricity data for 2018, the Council’s power planning staff reported in the fall of 2019 that the 2018 winter was warmer on average than the previous 91 winters. UTC staff requests additional information on how PSE intends to assess the climate sensitivity in future years of the utility’s load-resource balance and potential effects from changes in temperature/streamflow. Does PSE intend to use projected temperatures or streamflow distribution rather than historic distributions? Further, will PSE model unplanned outages linked to climate change in its IRP analysis, such as wildfires or other extremes like floods, snow pack shortage, or concurrent weather-related events?	
6/4/2020	Katie Ware, Renewables Northwest	*See attached PDF for comments (2020-06-04 RNW Feedback PSE Generic Resource Assumptions.pdf)*	1. Thank you. 2. PSE is researching pumped storage hydro and will have an update in the consultation update. 3. PSE is reviewing the data sources provided and will have an update in the consultation update. 4. PSE is modeling solar + battery and wind + battery in the 2021 IRP. The consultation update will include these resources along with research that PSE is doing on efficiency gains for having co-located resources.

PSE IRP Consultation Update
Webinar 1: Generic Resources Assumptions
May 28, 2020

6/18/2020

The following consultion update is the result of stakeholder suggestions gathered through an online feedback form, collected between May 13 through June 4, 2020 and summarized in the June 11 feedback report. The report themes have been summarized and along with a response to the suggestions that have been implemented. If a suggestion was not implemented, the reason is provided.

Pumped Storage Hydro

PSE received feedback from Nate Sandvig, National Grid Ventures, Bill Pascoe, Pascoe Energy representing Absoroka Energy & Orion Renewables, Katie Ware and Max Greene, Renewable Northwest; Fred Huette and Joni Bosh, Northest Energy Coalition (NWEC); Kathi Scanlan, WUTC staff; and Vlad Gutman-Britten, Climate Solutions, on the cost and operating assumptions of pumped storage hydro. This feeback included:

1. Overnight capital cost (cost that does not include interest/cost of capital)

   PSE has further reviewed other data sources for the capital cost of pumped storage hydro and has included the estimates from the Pacific Northwest National Laboratory (PNNL) report on energy storage. This estimate was already included as DOE Hydrowires 2019. Further, PSE has reviewed the assumptions for PacifiCorp's cost estimate (PacifiCorp, 2019 IRP) and concluded that it is very similar to the Swan Lake project and removed the PacifiCorp estimate so it is not double counted. The capital cost has been updated in the revised summary workbook Excel file for the generic resources assumptions available on PSE's IRP website under materials for Webinar 1 on pse.com/irp.

   Katie Ware, Renewable Northwest, notes that the PacifiCorp's draft IRP Pumped Storage Hydropower (PSH) generic resource looks to be based on Swan Lake. PSE read through PacifiCorp's generic resource assumptions and agrees, that their generic PSH resource appears to be the same as Swan Lake. PacifiCorp's draft IRP cost estimate was removed so that there isn't any double counting. Renewable Northwest also recommended additional review of the 2019 NWE Draft IRP (High) value. PSE reviewed NWE's costs and as a result will average NWE high and low cost estimates and then use the "mid" for the PSH capital cost average.

2. Operating characteristics

   PSE has reviewed the feedback received and contacted certain stakeholders (for example, Nathan Sandvig, National Grid Ventures; Bill Pascoe, Absaroka Energy & Orion Renewables, Fred Huette, Northwest Energy Coalition (NWEC)) to further discuss operating characteristics of pumped storage hydro.

   a. Nameplate capacity. The nameplate capacity will be reduced to 50 MW to assume a joint ownership and the ability to size to need.
   b. Operating range. The operating range will be updated to use 0% to 100% as supplied by Bill Pascoe and recommended by NWEC.
   c. Ramp rate. Newer technology allow the units to ramp at 20 MW/seconds. This is an input into the Plexos flexilibty model.
   d. Discharge rate. The input into the Aurora is the total energy of storage and the model will optimize the hours and energy used.

Battery Energy Storage System

PSE received feedback from Kathi Scanlan, WUTC staff, on using the Pacific Northwest National Labs (PNNL) report on energy storage. PSE reviewed the document and has included the cost estimates in the revised summary workbook Excel file for the generic resources assumptions available on PSE's IRP website under materials for Webinar 1 on pse.com/irp. PSE has also added the 2-hr Lithium Ion battery, and the 4-hr and 6-hr flow battery as resources options for the 2021 IRP.

Katie Ware, Renewable Northwest, and Vlad Gutman-Britten, Climate Solutions, provided feedback on using the Lazard levelized cost estimates. The discussion is provided below under captital costs, vintage year.

Vlad Gutman-Britten, Climate Solutions, provided feedback on on the PacifiCorp high battery storage capital cost. The high capital cost refers to a smaller 1 MW battery, so the cost was removed from the average and PSE will only use the cost estimate for the larger 15 MW battery.

PSE received feedback from Bill Pasco, Absoroka Energy & Orion Renewables, on battery degredation. The battery systems are assumed to have 0% degradation with an increased fixed O&M costs. This higher fixed costs are for maintenance over time to prevent the degredation.

Hybrid Resources

PSE received feedback from Fred Huette and Joni Bosh, NWEC; Kathi Scanlan, WUTC staff; Vlad Gutmen-Britten, Climate Solutions; Katie Ware and Max Greene, Renewable Northwest, on modeling hybrid or co-located resources such as solar + battery and wind + battery. In the 2019 IRP process, a 100 MW solar PV plus a 25 MW 2hr Lithium Ion battery was modeled with a 10% benefit to costs for co-locating the resource. The benefit represents that the battery can use the same substation and interconnection as the solar project. Also the battery received the benefit of the solar Investment Tax Credit (ITC) since it was connected to the solar project. This same resource will be modeled in the 2021 IRP and a wind + battery resource will be added as well. PSE will model a 100 MW wind project located in Washington with a 25 MW 2hr Lithium Ion battery. The costs will be modeled with a 10% reduction for the benefit of co-location. The revised summary excel file has been updated to include these resources.

Capital Costs

Many stakeholders gave feedback on the data sources used for the capital cost average.

1. **Dated information.** PSE received feedback from Fred Huette and Joni Bosh, NWEC, and Vlad Gutman-Britten, Climate Solutions, about using dated sources. PSE has made sure that only the most current information is used for the cost averaging. The updated data is included in the revised summary Excel file. Older data from 2016/2017 is included in the file for comparison purposes, but is not used in the cost average cacluation.
2. **Other utilitiy cost estimates.** Vlad Gutman-Britten, Climate Solutions, suggested that averaging data for capital costs should not be based on so many utility IRP projections. We feel this in an important data point since utilities usually hire a consulting firm to develop this information, as it gives an important perspective from the utility point of view. PSE will keep the other utility cost estimates in the cost average including PSE's 2019 IRP process estimates from HDR (Generic Resource Costs of Integrated Planning, October 2018).
3. **ATB low cost estimate.** Fred Huette and Joni Bosh, NWEC, suggested to use both the low and mid National Renewable Energy Laboratory (NREL) ATB cost estimate. Per the NREL website, the mid case is the most likely scenario, so PSE will only include the mid cost estimate in the cost average and not add the low.

    Three future scenarios (Constant, Mid, and Low technology cost) through 2050 to reflect a range of perspectives based on published literature:

    a. **Constant Technology Cost Scenario:** Base Year (or near-term estimates of projects under construction) equivalent through 2050 maintains current relative technology cost differences and assumes no further advancement in R&D.
    b. **Mid Technology Cost Scenario:** Technology advances through continued industry growth, public and private R&D investments, and market conditions relative to current levels that may be characterized as "likely" or "not surprising."
    c. **Low Technology Cost Scenario:** Technology advances that may occur with breakthroughs, increased public and private R&D investments, and/or other market conditions that lead to cost and performance levels that may be characterized as the "limit of surprise" but not necessarily the absolute low bound."

4. **Cost curves.** At the suggestion of Fred Huette and Joni Bosh, NWEC, and Vlad Gutman-Britten, Climate Soluations, PSE has compared the Annual Energy Outlook (AEO) cost curves and the NREL ATB (NREL, 2019 Annual Technology Baseline) cost curves. PSE will use the NREL cost curves for future capital costs. This update has been reflected in the revised summary Excel file.
5. **Owner's costs.** Vlad Gutman-Britten, Climate Solutions, requested additional information of the costs that go into owner's costs. Owner's costs are included in overnight costs and are different than Allowance for Funds Used During Construction (AFUDC). The capital costs shared with the IRP stakeholders on May 28 represent "Overnight Capital Costs" which estimate the cost of building the project "overnight" and therefore do not include extra costs incurred during construction. Capital costs are inclusive of the Engineering, Procurement and Construction (EPC) plus the Owner's costs (financing costs), but generally do not include interconnection costs.
6. **Allowance for Funds Used During Construction (AFUDC).** PSE will assume a generic assumption of 10% to the overnight cost to reflect AFUDC from the 2019 IRP process. The revised summary Excel file has been updated to include the total all-in costs that include AFUDC.
7. **Interconnection costs.** The the assumption from the 2019 IRP process will be used for the 2021 IRP. This includes to cost of a substation, 5 miles of transnsmission lines, and 5 miles of gas pipline for the natural gas (NG) . A full discussion of the assumption is included in the HDR report (Generic Resource Costs of Integrated Planning, October 2018) on the PSE's IRP website. The revised summary Excel file has been updated to include the total all-in costs that include interconnection costs.
8. **Vintage year for average**. Many of the data sources used provide costs for different vintage years. PSE used the year with the most data and averaged across data sources that provided costs for that particulat vintage year.This meant that certain data sources were left out because costs were provided for a different year. For example, the battery storage resource was averaged for the year 2020 since that had the most data points. But this meant that the costs for the Lazard report (2019 Levelized Cost of Energy) were left out since those were for a 2018 vintage plant. The different data sources did not provide any information on inflation to change the costs into a different vintage and PSE did not make any assumptions to change the vintage year. For the 2021 IRP, PSE will remain with this assumption, but is open to suggestions for how to handle it in future IRPs.

Economic Life

PSE received feedback from Kathi Sclanlan, WUTC staff, on the assumed economic life of resources stating the solar photovoltaics (PV) economic life has substatiantially increased. PSE has researched this and found that the current manufactors of solar PV will warranty the panels for up to 25 years. Given this information, PSE will update the economic life of solar from 20 to 25 years.

Bill Pascoe, Absaroka Energy & Orion Renewables, asked what is the assumed operating life for pumped stoage hydro (PSH) and battery storage. PSH is assumed to have a 30 year-life and batteries are assumed to have a 20-year life.

Hydrogen as a Fuel

Many stakeholders, including Kevin Jones and Rob Briggs of Vashon Climate Action Group and Doug Howell of the Sierra Club, gave feedback on using hydrogen as a fuel source for the natural gas generators. PSE has consulted with industry experts and thermal plant engineers. This is an emerging fuel source and PSE will continue to monitor the progress of the technology and applications in the US and abroad, as well as continue our involvement in the development as a member of Renewable Hydrogen Alliance. Many companies are developing hydrogen ready gas turbines that can start with a blended hydrogen to NG fuel and in future years retrofit the combustor to run on 100% hydrogen. Though the technology for turbine exists today, the supply for 100% hydrogen does not. The current gas transportation pipelines can only handle a 3% - 10% hydrogen mix. To move to a higher concentration of hydrogen would require new pipelines or electrolyzer and storage on site. The cost to create the hydrogen fuel is currently unknown. PSE is researching the cost of a hydrogen ready gas turbine and the cost for future retrofits to handle 100% hydrogen along with the costs for the fuel supply. PSE will provide an update on our findings as we begin the portfolio modeling and if there is enough iformation to include it as a resource option in the 2021 IRP. Even if there is not enough information to include it as a resource option, the 2021 IRP will include a discussion of hydrogen as a fuel and the technology need for the fuel supply.

Summary of all Updates

PSE appreciates the feedback provided by stakeholders. In summary, the Excel summary workbook includes the following changes:

- Pumped Storage Hydro overnight capital costs revised to include more data sources and averaging across vintage year 2021 instead of 2020.
- Pumped Storage Hydro size assumption has been revised to 50 MW. PSE will also update operating characteristics for PSH to reflect newer techonology.
- Considering hybrid resources, certain changes have been made in the summary Excel file. Wind + battery resource as been added. PSE will model a 100 MW wind project located in Washington with a 25 MW 2 hr Lithium Ion battery.
- PSE has adopted the NREL data to generate cost curves.
- AFUDC and interconnection costs have been added in a new tab to calculate the all-in capital costs that will be used in the models.
- PSE will update the economic life of solar from 20 to 25 years.
- PSE will further develop costs concerning hydrogen as a fuel for application in the 2021 IRP analysis or if that is not feasible, the 2021 IRP book will include a robust discussion of the state of the industry concerning hydrogen.
- Lithium Ion 2-hr battery and flow 4-hr and 6-hr battery added. PSE was able to collect some other data sources from the PNNL energy storage report and some other utility IRPs besides the HDR report (Generic Resource Costs of Integrated Planning, October 2018).

Figure 1 below is a table comparing the costs from the 2019 IRP, the draft 2021 IRP as presented on May 28, and the updated capital costs after stakeholder feedback. The following table is also located in the revised Excel summary file under the tab "summary" and available for stakeholders can track the costs and calculations.

Figure 1: Overnight capital costs

(2021 Vintage, 2016 U.S. Dollars)	**Overnight Capital Cost ($/kW)**		
	2019 IRP	2021 IRP draft	2021 IRP proposed
CCCT	991	927	943
Frame Peaker	618	660	664
Recip Peaker	931	1,248	1,256
Solar Utility	1,422	1,226	1,264
Solar Residential	--	2,848	2,957
Onshore Wind	1,438	1,484	1,421
Offshore Wind	5,730	4,971	4,377
Pumped Storage	2,176	2,515	2,145
Battery (4hr, Li-Ion)	2,427	1,900	1,542
Battery (2hr, Li-Ion)	1,455	--	849
Battery (4hr, Flow)	1,625	--	2,051
Battery (6hr, Flow)	2,244	--	2,860
Solar + Battery	2,698	--	1,901
Wind + Battery	--	--	2,043
Biomass	7,744	5,119	5,246

Figure 2 below is a table showing how the AFUDC and interconnection costs are added to the overnight for the final all-in costs that PSE will be using for portfolio modeling. The following table is also located in the revised Excel summary file under the tab "summary" and available for stakeholders can track the costs and calculations. The cost curve with costs by vintage year are also included with this table.

Figure 2: All-in capital costs

(2021 Vintage, 2016 U.S. Dollars)	Overnight Capital	AFUDC	Interconnection Costs	Total All-In Capital cost
CCCT	943	94	91	1,128
Frame Peaker	664	66	134	865
Recip Peaker	1,256	126	143	1,525
Solar Utility	1,264	126	100	1,489
Solar Residential	2,957	296	--	3,252
Onshore Wind	1,421	142	47	1,610
Offshore Wind	4,377	438	65	4,878
Pumped Storage	2,145	214	47	2,406
Battery (4hr, Li-Ion)	1,542	154	367	2,063
Battery (2hr, Li-Ion)	849	85	367	1,301
Battery (4hr, Flow)	2,051	205	367	2,624
Battery (6hr, Flow)	2,860	286	367	3,513
Solar + Battery	1,901	190	420	2,511
Wind + Battery	2,043	204	373	2,620
Biomass	5,246	525	607	6,378

Webinar #2: Electric Price Forecast Q&A

DRAFT 6/11/2020

Overview

On June 10, 2020 Puget Sound Energy hosted an online meeting with stakeholders to discuss the electric price forecast. Stakeholders shared their input on incorporating clean energy policies in baseline assumptions to inform the electric price forecast. Participants were able to submit feedback on the webinar and meeting materials prior to and after the webinar occurred. Additionally, participants were able to ask questions using a chat box provided by the GoToMeeting platform.

Below is a report of the questions submitted to the chat box. Answers to the questions were provided verbally by IRP staff during the webinar. Please note that questions were answered in order of relevance to the topic currently being discussed. Questions regarding other topics were answered at the end of the webinar session.

To view a recording of the webinar and to hear responses from staff, please visit the project website at pse-irp.participate.online.

Attendees

A total of 68 people attended the meeting, including project staff and six attendees who only called into the meeting and did not identify themselves.

Attendees included:

James Adcock, Larry Becker, Charlie Black, Joni Bosh, Robert Briggs, Koch, Cathy, Stephanie Chase, Zhi Chen, Weimin Dang, Cody Duncan, Kara Durbin, Nancy Esteb, Spencer Gray, Brian Grunkemeyer, Vlad Gutman-Britten, Kelly Hall, Warren Halverson, Lori Hermanson, Fred Heutte, Mike Hopkins, “J”, Elizabeth Hossner, Brandon Houskeeper, David Howarth, Doug Howell, Charles Inman, Magat, Jennifer, Kevin Jones, Eric Kang, Dan Kirschner, Michele Kvam, Sarah Laycock, Virginia Lohr, Penny Mabie, Kate Maracas, Kassie Markos, Don Marsh, Sheri Maynard, Jennifer Mersing, David Meyer, Irena Netik, Valerie O'Halloran, Court Olson, Anthony O'Rourke, Bill Pascoe, David Perk, Alison Peters, Kathi Scanlan, Gurvinder Singh, Alexandra Streamer, Tyler Tobin, Rahul Venkatesh, Katie Ware, Eddie Webster, Elyette Weinstein, Willard (Bill) Westre, Bob Williams, John Williams, Scott Williams, and Zacarias Yanez.

Questions Received

Questions from attendees are posted in the order in which they were received. The first four rows represent questions submitted in advance through the Feedback Form. The webinar began at 1:30 PM PDT and ended at 4:30 PM PDT. A full verbatim chat log is available as an appendix.

Slide number	Question	Sent by
Intro	Can you please enumerate in detail all of the various types of historical data used anywhere in any of your modeling efforts, including the earliest calendar year and latest calendar year from which each of those historical data types was used.	James Adcock
24	On this page you state for the "2021 IRP electric price update" that the "Regional Demand from the 7th Power Plan" didn't change. Why didn't it change? Why would you not assume a downturn in demand due to the downturn in the economy due to COVID-19? Shouldn't your regional demand assumptions be updated to recognize the reality of the huge change in the regional economy, and thereby demand, caused by COVID-19? Economists are projecting that it will take a decade for the US Economy to recover from COVID-19.	James Adcock
28	Can you please list all of the assumptions, and all of the data used, including historical range of dates from which that data was collected, in generating this plot?	James Adcock
42	Given that CETA is now "the law of the land" why is it appropriate to develop a scenario where you assume that you do not have to meet the CETA requirements?	James Adcock
Welcome Slide	is this the link for go to meeting that will be used for the future meetings? ditto for the code?	Joni Bosh
Welcome Slide	Can everyone see questions and comments posted here?	Doug Howell
8	Slide 8-Staff requests when discussing IRP scenarios used to develop planning assumptions, including alternative scenarios and ‘futures’, PSE clearly define what it means by each case, including ‘base case’ and clearly label and reference what is meant for each case for the discussion today	Kathi Scanlan
11	Slide 11-what other analyses needed for the company (last bullet)?	Kathi Scanlan
11	Do avoided costs take into account both avoided generation and avoided T&D?	Don Marsh

Slide number	Question	Sent by
8	Slide Page 8 Raise Hand. But what *are* your "planning assumptions?" Whenever we ask you what is your input modeling data, including what range of calendar dates for each of those input datas, you refuse to answer us. And this has been going on for more than 10 years now. The input modeling data IS part of your "planning assumptions"	James Adcock
11	Slide Page 11 Raise Hand. How do you model the difference in "market prices" between emitting sources of electricity vs. non-emitting sources of electricity? Moving forward towards 2030 the great majority of your electricity needs to come from non-emitting sources.	James Adcock
11	Just to clarify, is the electric price forecast the same value for all the listed uses on slide 11?	Joni Bosh
13	Slide 13-Clarifying Question: When is PSE planning to discuss its resource adequacy and flexibility model(s) in greater detail? Dates of webinars/meetings?	Kathi Scanlan
13	Is Plexos a power flow model?	Kate Maracas
14	Bullet 2- what fundamentals are your referring to, specifically? (I am asking for examples of fundamentals on slide 14. Thanks)	Elyette Weinstein
14	S-14 What MW transmission Constraint numbers are you using for Mid-C and MT wind	Bill Westre
14	I hope James Adcock's statement that his question was not answered will be treated as a question and that Elizabeth will attempt to actually answer his original question.	Virginia Lohr
13	Second Kathi's question - interested in the assumptions and values in the RA model.	Joni Bosh
15	General question: If all resources are lumped into a broad energy price then how does your analysis drive a reasonable resource portfolio	John Williams
16	Do you count only those resources that are permitted, not those that are planned? Slide 16	Joni Bosh
16	What date is the data obtained from NWPCC (regional load)?	Kathi Scanlan
16	Slide 16. How do you in fact model "Regional Load" as an input? What data inputs do you use as inputs to your modeling of "Regional Load?" What range of dates of data inputs used as data to generate your "Regional Load" modeling do you use?	James Adcock
17	On slide 17, does "Resource Assumptions" incorporate any feedback PSE received from the May 28th webinar on Generic Resource Assumptions?	Katie Ware

Slide number	Question	Sent by
17	Slide 17 - PSE needs to assume social cost of carbon ($74/ton) for all thermal resources. Why isn't this being reflected?	Doug Howell
16	SLide 16 so Aurora is not used to determine the portfolio?	John Williams
17	Why is SCOC not added to box 6 as well	Bill Westre
17	Slide 17: why are there no new thermal plants built in WA? Is that a constraint on the model? Is SCC only applied to facilities built in Washington?	Kelly Hall
*****	I think I am directing my questions to specific issues that PSE is mentioning in passing on the page of the slides that PSE is presenting.	James Adcock
17	Slide 17 indicates that the Social Cost of Carbon (SCoC) is included for thermal builds in Washington. Is the SCoC used for dispatching existing thermal resources in Washington?	Charlie Black
16	the question of counting new resources is an important one -- we are already in a situation where most new resources across the west coming online in the next 5 years will not have commitments (contracts, under construction) much more than 2 or 3 years in advance	Fred Heutte
17	note that the NW Council's draft 2021 Plan load forecast is still being refined and will be based on a climate-adjusted baseline -- the initial model inputs will be available soon and PSE should consider using that as perhaps a model sensitivity for the 2021 IRP	Fred Heutte
17	No. SCC needs to apply to thermal power coming into WA	Doug Howell
17	Katie Ware's question was actually a yes/no question. I don't recall hearing if the answer was Yes or No. Please clarify for me.	Virginia Lohr
17	Follow up on slide 17: when you say SCC only on Washington as a result of CETA, do you mean energy delivered to Washington (but facility may be in another state) or only facilities physically located in Washington?	Kelly Hall
17	How PSE internalizes SCC should also be applied to price. You have to assume you are paying this price for planning purposes.	Doug Howell
17	Second Doug Howell's comment that out of state carbon resources need to have the social cost of carbon attached for correct modelling.	Court Olson
17	on the Council's planning process, we are hearing that early modeling results may be available in August or September, though the official draft plan won't be out until early next year	Fred Heutte

Slide number	Question	Sent by
19	will you incorporate other policies and commitments from utilities as well, such as Xcel, Idaho Power, and Avista that have committed to 100% as well. And CO's law that utilities consider SCC and make progress towards 90% carbon reduction by 2050? These will also impact price forecasts.	Kelly Hall
19	The Wood Mac gas price forecast is now two years old. Why isn't PSE using a more current forecast?	Charlie Black
19	To clarify Slide 19, these are changes (particularly WoodMac 2018 gas price) from 2017 IRP to 2019 Progres Report. Are these the assumotions to be used in this IRP?	Dan Kirschner
21	Slide 21-Please explain the light green slivers on top of the blue non-emitting/renewable resources 2021-2027.	Kathi Scanlan
21	s-21 Where is existing WA wind?	Bill Westre
21	Slide 21 Why would you assume that the "Renewable Needs Ramp" starts at the red line of about 10M? and not the blue bar at about 70M? CEIP requires a demonstration of "linear progress ramp."	James Adcock
17	Please answer Kelly Hall's question on slide 17: when you say SCC only on Washington as a result of CETA, do you mean energy delivered to Washington (but facility may be in another state) or only facilities physically located in Washington?	Kevin Jones
21	If the state has a sharp increase in need in 3 years, is it reasonable to assume that prices of new facilities will increase non-linearly due to a spike in demand for new projects? How do you model this effect?	Brian Grunkemeyer
21	Energy demand has not been rising at the rate indicated on this slide as "target". Please confirm that this "target" line is strictly reflecting the renewable energy ramp up needed to meet the law. If so, what future total energy demand is assumed for 2045?	Court Olson
24	Slide 24-What date is PSE for the consultant(s) gas price forecast? Is it one consultant or a blend of consultants gas forecast(s) used as input to Aurora?	Kathi Scanlan
24	Are those estimated MW builds for Solar and wind for the base year or over the 20 years? Sorry, I had interference and missed a bit of what you were saying.	Joni Bosh
25	Slide 25 Given that US economists are predicting that the COVID-ravaged US economy will not fully recover until the end of the decade, shouldn't the long-term gas prices be updated? And that gas price predictions made before the COVID-19 crash don't have relevancy anymore?	James Adcock

Slide number	Question	Sent by
28	Slide 28 What input data assumptions are you using when making this slide? How can we interpret this slide if you don't tell us what assumptions you made when creating this slide? For example, is this slide also based on the assumption of "No New Washington State NG Builds?"	James Adcock
28	my question on slide 28 is the impact of hybrids (solar/wind plus storage), standalone storage and flexible demand at scale on market prices as compared to renewables by themselves	Fred Heutte
28	The cost of gas to society has not gone down. The will of humanity is to eliminate all fossil fuels so that we have any hope of a future. I don't fully understand the things you are saying about social cost of carbon and how and when it will be incorporated, but we need to get off of "natural" gas immediately. Artificially low prices for gas, perhaps because of reduced demand, because more and more people know we need to get off of gas, should not be used to justify more gas. Will your modelling lead us to the future that is our only hope for survival?	Virginia Lohr
28	Will PSE make the hourly power price forecast results availalable to the IRPAG?	Charlie Black
28	Slide 28 follow-up -- Are you *seriously* suggesting that this is a reasonable prediction of future volutility???	James Adcock
28	Slide 28 Wouldn't people just build NG Peakers, Battery Storage, or Pumped Hydro to "arbitrage" these high price variability and differential???	James Adcock
29	Slide 29: why did electric price forecast increase on slide 29 when on slide 27 it appears to have declined slightly?	Kelly Hall
	Will you address Charlie Black's question about hourly price forecasts in the next part of the presentation?	Joni Bosh
Break	Why not allow more meeting time in the future so that there *is* enough time to answer questions?	James Adcock
33 - 34	How accurate historically is the demand forecasting you are using? How much demand can be reduced by extensive conservation? reduce the demand when you cannot meet the need with current resources	John Williams
38	Slide #38 - They can build renewables or "optimize their portfolios." Can you explain more concretely what you mean by optimizing a portfolio that can substitute for building renewables?	Robert Briggs

Slide number	Question	Sent by
34	Slide 34 - Have you given any thought as to how each of these modeled scenarios could affect CETA's incremental cost calculation?	Katie Ware
42	Question 1: What is PSE's base case scenario for electric price forecast - is PSE calling it "IRP Mid - Draft" in this presentation? Please clarify base case.	Kathi Scanlan
42	Question 2: Does PSE mean in the "No CETA" or absent those standards under CETA RCW 19.405.040(1) and 050(1) as well as implied cost of coal close-out in 2025? The "No CETA" scenario is not clear. For example, how does this scenario relate to the CETA incremental cost baseline and draft Clean Energy Implementation Plan (CEIP) draft rules? Staff requests a response to the connection to CETA requirements and CEIP draft rules.	Kathi Scanlan
42	Would you please refresh our memories on what year's data the 7th Power Plan was based on. Is there really no more recent data that could be used to update those projections?	Robert Briggs
Q&A	How is this recent demand data inputted into your modeling? Should more recent years be and climate warming be more highly weighted in your models?	Warren Halverson
Q&A	Will the wholesale power price forecasts be made available at the hourly price level of granularity?	Charlie Black
Q&A	In the context of the 2019 IRP Progress Report and changes compared to these 2021 draft numbers, would you discuss the three primary inputs that affect power prices and what you've seen in terms of changes in modeling and results thus far?	Kathi Scanlan
Q&A	Could you explain the rationale for the position that PSE does not apply the Social Cost of Carbon to electricity that comes in from other states when PSE calculates their IRP power price?	Kevin Jones
Q&A	I was puzzled by the comment made along with slide #26 that the 20-year low price for gas reflected delays in permitting LNG export facilities. Does this suggest that another 20 years of delays are anticipated in Kalama Methanol and Jordan Cove? Or did I mishear? In any case, it strikes me that a longer view on these prices is needed.	Robert Briggs

Slide number	Question	Sent by
Q&A	I know this meeting agenda does not include DR, but since we just completed the UTC DR Workshop, what issues and opportunities do you see for PSE to increase their adoption of DR in this IRP. I recall from the PSE SCC Workshop that little DR was adopted, leading one reviewer to say "there must be something wrong with your model". Do you think the model needs adjustment and was there any insights from the DR Workshop that suggests any specific adjustments?	Kevin Jones
Q&A	I look forward to that discussion My question - do you have any insights at this time?	Kevin Jones
Q&A	Let me rephrase with more content: Thanks for your reply on DR Elizabeth. My question - did PSE receive any insights on DR from the UTC DR Workshop?	Kevin Jones

Appendix

A full verbatim chat log from the meeting is available below. Questions sent only to the meeting organizers have not been included for brevity.

Name	Time sent	Comment
Doug Howell	1:44 PM	Can every one see questions and comments posted here?
John Williams	1:44 PM	yes
Alexandra Streamer	1:44 PM	Hi Doug - yes, all participants can see the questions and comments
Kathi Scanlan	1:44 PM	yes
Alison Peters	1:45 PM	Joni asked if today's meeting link will work for future meetings. No, there will be a new one each time. Thanks Joni. You can share any future comments or questions with "everyone" so everyone can see them. Thank you!
Kathi Scanlan	1:49 PM	Slide 8-Staff requests when discussing IRP scenarios used to develop planning assumptions, including alternative scenarios and 'futures', PSE clearly define what it means by each case, including 'base case' and clearly label and reference what is meant for each case for the discussion today
Kathi Scanlan	1:56 PM	Slide 11-what other analyses needed for the company (last bullet)?
Don Marsh	1:56 PM	Do avoided costs take into account both avoided generation and avoided T&D?
James Adcock	1:56 PM	Slide Page 8 Raise Hand. But what *are* your "planning assumptions?" Whenever we ask you what is your input modeling data, including what range of calendar dates for each of those input datas, you refuse to answer us. And this has been going on for more than 10 years now. The input modeling data IS part of your "planning assumptions" Slide Page 11 Raise Hand. How do you model the difference in "market prices" between emitting sources of electricity vs. non-emitting sources of electricity? Moving forward towards 2030 the great majority of your electricity needs to come from non-emitting sources.
Joni Bosh	1:56 PM	Just to clarify, is the electric price forecast the same value for all the listed uses on slide 11?
Joni Bosh	1:58 PM	Thanks
James Adcock	2:00 PM	That was not an answer.
Kathi Scanlan	2:01 PM	Slide 13-Clarifying Question: When is PSE planning to discuss its resource adequacy and flexibility model(s) in greater detail? Dates of webinars/meetings?
Kate Maracas	2:02 PM	Is Plexos a power flow model?
elyette weinstein	2:03 PM	Bullet 2- what fundamentals are your referring to, specifically?
Willard (Bill) Westre	2:03 PM	S-14 What MW transmission Constraint numbers are you using for Mid-C and MT wind

Name	Time sent	Comment
Virginia Lohr	2:04 PM	I hope James Adcock's statement that his question was not answered will be treated as a question and that Elizabeth will attempt to actually answer his original question.
Joni Bosh	2:04 PM	Second Kathi's question - interested in the assumptions and values in the RA model.
elyette weinstein	2:05 PM	I am asking for examples of fundamentals on slide 14. Thanks
John Williams	2:06 PM	General question: If all resources are lumped into a broad energy price then how does your analysis drive a reasonable resource portfolio
Alexandra Streamer	2:06 PM	Hi Bill - PSE will discuss transmission constraints in more detail during the June 30 webinar
Joni Bosh	2:08 PM	Do you count only those resources that are permitted, not those that are planned? Slide 16
Kathi Scanlan	2:08 PM	Slide 16-What date is the data obtained from NWPCC (regional load)?
James Adcock	2:09 PM	Slide 16. How do you in fact model "Regional Load" as an input? What data inputs do you use as inputs to your modeling of "Regional Load?" What range of dates of data inputs used as data to generate your "Regional Load" modeling do you use?
Katie Ware	2:09 PM	On slide 17, does "Resource Assumptions" incorporate any feedback PSE received from the May 28th webinar on Generic Resource Assumptions?
Doug Howell	2:09 PM	Slide 17 - PSE needs to assume social cost of carbon ($74/ton) for all thermal resources. Why isn't this being reflected?
John Williams	2:10 PM	SLide 16 so Aurora is not used to determine the portfolio?
Willard (Bill) Westre	2:10 PM	Why is SCOC not added to box 6 as well
Kelly Hall	2:11 PM	Slide 17: why are there no new thermal plants built in WA? Is that a constraint on the model? Is SCC only applied to facilities built in Washington?
John Williams	2:12 PM	Why are SCOS values not applied by each resource, since it is not uniform cross all resources.
James Adcock	2:13 PM	I think I am directing my questions to specific issues that PSE is mentioning in passing on the page of the slides that PSE is presenting.
Charlie Black	2:15 PM	Slide 17 indicates that the Social Cost of Carbon (SCoC) is included for thermal builds in Washington. Is the SCoC used for dispatching existing thermal resources in Washington?
Fred Heutte	2:18 PM	the question of counting new resources is an important one -- we are already in a situation where most new resources across the west coming online in the next 5 years will not have commitments (contracts, under construction) much more than 2 or 3 years in advance
Fred Heutte	2:20 PM	note that the NW Council's draft 2021 Plan load forecast is still being refined and will be based on a climate-adjusted baseline -- the initial model inputs will be available soon and PSE should consider using that as perhaps a model sensitivity for the 2021 IRP
Doug Howell	2:22 PM	No. SCC needs to apply to thermal power coming into WA

Name	Time sent	Comment
Virginia Lohr	2:23 PM	Katie Ware's question was actually a yes/no question. I don't recall hearing if the answer was Yes or No. Please clarify for me.
Kelly Hall	2:23 PM	Follow up on slide 17: when you say SCC only on Washington as a result of CETA, do you mean energy delivered to Washington (but facility may be in another state) or only facilities physically located in Washington?
Doug Howell	2:24 PM	How PSE internalizes SCC should also be applied to price. You have to assume you are paying this price for planning purposes.
Court Olson	2:25 PM	Second Doug Howell's comment that out of state carbon resources need to have the social cost of carbon attached for correct modelling.
Fred Heutte	2:27 PM	on the Council's planning process, we are hearing that early modeling results may be available in August or September, though the official draft plan won't be out until early next year
Kelly Hall	2:33 PM	Slide 19: will you incorporate other policies and commitments from utilities as well, such as Xcel, Idaho Power, and Avista that have committed to 100% as well. And CO's law that utilities consider SCC and make progress towards 90% carbon reduction by 2050? These will also impact price forecasts.
Charlie Black	2:33 PM	The Wood Mac gas price forecast is now two years old. Why isn't PSE using a more current forecast?
Dan Kirschner	2:34 PM	To clarify Slide 19, these are changes (particularly WoodMac 2018 gas price) from 2017 IRP to 2019 Progres Report. Are these the assumotions to be used in this IRP?
Kathi Scanlan	2:37 PM	Slide 21-Please explain the light green slivers on top of the blue non-emitting/renewable resources 2021-2027.
Willard (Bill) Westre	2:38 PM	s-21 Where is existing WA wind?
Kelly Hall	2:38 PM	Slide 21: Is this assuming that CETA investments occur in 2028 and beyond, or are you simply identifying a need? If you are projecting builds, do you expect any differences if you assume these investments occur earlier, starting in 2022 to demonstrate continuous progress as reuqired by CETA?
Irena Netik	2:39 PM	Response to Charlie Black and Dan Kirschner: Jennifer only covered the changes from 2017 IRP to 2019 IRP progress report. 2021 IRP assumptions will be covered next.
elyette weinstein	2:39 PM	Kathy the light green bars are nuclear.
Fred Heutte	2:39 PM	Gas price risk is a complex issue and I'm very wary of simply accepting any forecast especially my own. We're seeing a lot more short term variability right now but the big question for me is what gas prices will look like by 2025 and after and there, I am not satisfied by the conventional wisdom that it will be quite low -- that may be, but we need a sense of upside risk
James Adcock	2:39 PM	Slide 21 Why would you assume that the "Renewable Needs Ramp" starts at the red line of about 10M? and not the blue bar at about 70M?
Kevin Jones	2:40 PM	Please answer Kelly Hall's question on slide 17: when you say SCC only on Washington as a result of CETA, do you mean energy delivered to Washington (but facility may be in

Name	Time sent	Comment
		another state) or only facilities physically located in Washington?
James Adcock	2:41 PM	(continued) CEIP requires a demonstration of "linear progress ramp."
James Adcock	2:44 PM	You are not answering my question again, I was not asking about PSE, I was asking about THIS SLIDE about Washington State.
James Adcock	2:44 PM	PSE refused to answer my question again.
Brian Grunkemeyer	2:44 PM	If the state has a sharp increase in need in 3 years, is it reasonable to assume that prices of new facilities will increase non-linearly due to a spike in demand for new projects? How do you model this effect?
Court Olson	2:44 PM	Energy demand has not been rising at the rate indicated on this slide as "target". Please confirm that this "target" line is strictly reflecting the renewable energy ramp up needed to meet the law. If so, what future total energy demand is assumed for 2045?
Kathi Scanlan	2:47 PM	Slide 24-What date is PSE for the consultant(s) gas price forecast? Is it one consultant or a blend of consultants gas forecast(s) used as input to Aurora?
Fred Heutte	2:47 PM	a point on slide 22 I will want to do a Raise Hand discussion later -- nominal dollars vs real/discounted present value dollars
Don Marsh	2:49 PM	Court's question reflects our confusion because the Demand Forecast is presented so late in the assumptions portion of the IRP. We would really like to understand demand at the regional level and PSE's service area earlier in the IRP process.
Joni Bosh	2:51 PM	Are those estimated MW builds for Solar and wind for the base year or over the 20 years? Sorry, I had interference and missed a bit of what you were saying.
James Adcock	2:53 PM	Slide 25 Given that US economists are predicting that the COVID-ravaged US economy will not fully recover until the end of the decade, shouldn't the long-term gas prices be updated? And that gas price predictions made before the COVID-19 crash don't have relevancy anymore?
Dan Kirschner	2:54 PM	Slide 25: this appears to be a reasonable approach for gas prices given various sources/forecasts.
Irena Netik	2:56 PM	Response to Kevin Jones: for the electric power price forecast, SCC is applied to facilities physically located in WA state
James Adcock	2:56 PM	Slide 28 What input data assumptions are you using when making this slide? How can we interpret this slide if you don't tell us what assumptions you made when creating this slide? For example, is this slide also based on the assumption of "No New Washington State NG Builds?"
Fred Heutte	2:56 PM	my question on slide 28 is the impact of hybrids (solar/wind plus storage), standalone storage and flexible demand at scale on market prices as compared to renewables by themselves
Don Marsh	3:00 PM	Slide 28 growing price variability makes a great case for energy storage to alleviate high prices during outlier hours. I hope PSE will have some great analysis regarding the

Name	Time sent	Comment
		economic case for energy storage, especially as battery prices fall and capacities rise. Many utilities are incorporating more battery projects in their plans than PSE seems to be.
Virginia Lohr	3:02 PM	The cost of gas to society has not gone down. The will of humanity is to eliminate all fossil fuels so that we have any hope of a future. I don't fully understand the things you are saying about social cost of carbon and how and when it will be incorporated, but we need to get off of "natural" gas immediately. Artificially low prices for gas, perhaps because of reduced demand, because more and more people know we need to get off of gas, should not be used to justify more gas. Will your modelling lead us to the future that is our only hope for survival?
Fred Heutte	3:04 PM	let me add to my previous comment on slide 28, I would also include pumped storage not just battery
Charlie Black	3:04 PM	Will PSE make the hourly power price forecast results availalable to the IRPAG?
James Adcock	3:04 PM	Slide 28 follow-up -- Are you *seriously* suggesting that this is a reasonable prediction of future volutility???
Fred Heutte	3:06 PM	just to note, the California ISO says that of new entries to their transmission queue in 2019, 95% of the new solar is hybrid and 75% of wind
James Adcock	3:06 PM	Slide 28 Wouldn't people just build NG Peakers, Battery Storage, or Pumped Hydro to "arbitrage" these high price variability and differential???
Kelly Hall	3:07 PM	Slide 29: why did electric price forecast increase on slide 29 when on slide 27 it appears to have declined slightly?
Joni Bosh	3:11 PM	Will you address Charlie Black's question about hourly price forecasts in the next part of the presentation?
Irena Netik	3:12 PM	Response to Charlie Black: The hourly gas price forecast is confidential. PSE purchases it from Wood Mackenzie. Under our contract we are only able to publish the results provided here.
Fred Heutte	3:12 PM	Concerning slide 29, an important underlying assumption is that market prices are effectively heat rate based, that is, the marginal unit is usually a gas plant which must recover its fuel and start costs -- while true now (except in the spring runoff), I wonder how true that will be in the future as gas is displaced by clean supply and flexible demand -- just a thought
James Adcock	3:13 PM	Why not allow more meeting time in the future so that there *is* enough time to answer questions?
Don Marsh	3:15 PM	Feedback: a price forecast without some accounting of energy storage seems pretty sketchy, I'm sorry to say.
Fred Heutte	3:16 PM	also, market design (the potential EIM Enhanced Day Ahead Market) and the potential NW Power Pool resource adequacy program could have a significant benefit for reducing and stabilizing market prices, but neither of those is yet in place
Fred Heutte	3:18 PM	one of the disadvantages of a four-year IRP cycle is that policy and market changes are evolving at a faster pace than that
James Adcock	3:18 PM	Slide 33 Comment: This assumes that there is an "open" market where utilities share their renewable resources "as needed" [perhaps at a price] with other utilities. But there is

Name	Time sent	Comment
		no such "open market", AND we know historically, for a variety of reasons, there are "utilities" [and I include BPA in that category] who choose not to openly share their renewables with other utilities. If this continues to be the case, then WA-wide *more* new renewables would need to be built than you assume.
Kate Maracas	3:18 PM	To Fred and all - but EDAM and the NWPP RA program are very likely to be in place - in some form, during this planning horizon.
John Williams	3:22 PM	Slide 33 and 34 How accurate historically is the demand forecasting you are using? How much demand can be reduced by extensive conservation? reduce the demand when you cannot meet the need with current resources
Robert Briggs	3:28 PM	Slide #38 - They can build renewables or "optimize their portfolios." Can you explain more concretely what you mean by optimizing a portfolio that can substitute for building renewables?
James Adcock	3:28 PM	Slide 38 Feedback as you have requested: I personally put a very high priority on PSE *actually* meeting the 2030 "80/20" requiremens, including "linear progress towards that goal" until 2030. In order to make that more likely I would prefer that PSE assume the higher level of shortfall -- i.e. that other utilities may choose to NOT "fairly" make all of their renewables available to PSE.
Kevin Jones	3:28 PM	Penny - we are here donating our time. We expect dialogue. Please don't tell me you are protecting my time, which I am donating to this process. My time is wasted if we don't achieve dialogue, which we are again failing to achieve.
Fred Heutte	3:29 PM	Just want to underscore the importance of revisiting or perhaps adjusting from the Council's 7th Plan forecast which was basically locked down in mid-2015.
Katie Ware	3:29 PM	Slide 34 - Have you given any thought as to how each of these modeled scenarios could affect CETA's incremental cost calculation?
James Adcock	3:31 PM	Agree with Kevin Jones -- with the current format, where we cannot directly ask questions, and follow-up to clarify our questions and actually get meaningful answers -- this current choice of PSE meeting format where we are not actually allowed to talk to PSE presenters, and are not actually allowed to directly ask questions and clarifications -- which is "wasting my time."
Virginia Lohr	3:33 PM	Giving PSE time to get through their presentation clearly is simply "informing." People attending these meetings are not doing so simply to be informed, but clearly want to have meaningful input into the process. There appears still to be something broken in the system when the goal is for PSE to get through their presentation. This is no change or even a back-track from the last IRP process. Your feedback requested on slide 38 seems rather simplistic given the entire slide deck.
David Perk	3:34 PM	+1 to what Virginia Lohr writes about informing vs dialog.

Name	Time sent	Comment
Kathi Scanlan	3:34 PM	Question 1: What is PSE's base case scenario for electric price forecast - is PSE calling it "IRP Mid - Draft" in this presentation? Please clarify base case. Question 2: Does PSE mean in the "No CETA" or absent those standards under CETA RCW 19.405.040(1) and 050(1) as well as implied cost of coal close-out in 2025? The "No CETA" scenario is not clear. For example, how does this scenario relate to the CETA incremental cost baseline and draft Clean Energy Implementation Plan (CEIP) draft rules? Staff requests a response to the connection to CETA requirements and CEIP draft rules.
John Williams	3:35 PM	The sensitivity of multiple variable can be addressed by doing a linear regression (?). This may help to determine the "best answer" to the possible scenarios. You need a consulting statistian which I am obviously not.
James Adcock	3:36 PM	Slide 43: I'd like to see a "COVID-19 Crash" compatible scenario, which assumes Low Demand *and* Low Gas Prices, *and* CETA requirements, including "linear implementation ramp" from 2020 to 2030.
Robert Briggs	3:36 PM	Would you please refresh our memories on what year's data the 7th Power Plan was based on. Is there really no more recent data that could be used to update those projections?
Doug Howell	3:36 PM	Slide 42. CETA $74/ton is now an average or baseline, but certainly not a high case scenario. InterAgency Working Group has high of $123/ton (2007 dollars)
Robert Briggs	3:38 PM	The comment that the low gas prices were based on delays in approving LNG
Dan Kirschner	3:38 PM	7th Power Plan published in early 2016
Robert Briggs	3:39 PM	2016
Fred Heutte	3:39 PM	The 7th Plan was formally adopted in February 2016.
Fred Heutte	3:41 PM	raise hand -- slides 22 and 27
James Adcock	3:42 PM	Raise Hand.
James Adcock	3:42 PM	Can I use the microphone?
Robert Briggs	3:43 PM	I agree with Fred on the real dollar comment!
Warren Halverson	3:43 PM	In PSE's Docket UE190529 & UG 19530, January 2020, PSE requested a roughly 7% increase in electric and natural gas prices. Simultaneously, the WSJ had an article entitled "Glut pushes natural gas prices below $2 -- a drop of 61% in two years -- several factors were mentioned.
Robert Briggs	3:44 PM	Two part comment on slide #28.
Warren Halverson	3:45 PM	How is this recent demand data inputted into your modeling? Should more recent years be and climate warming be more highly weighted in your models?
Alexandra Streamer	3:46 PM	@Warren, would you like to verbally state those questions or would you prefer that we read it?
Katie Ware	3:46 PM	Raised hand

Name	Time sent	Comment
Don Marsh	3:48 PM	Raise hand (IAP2 process)
James Adcock	3:49 PM	7th Power Plan was begun in 2010, after the 6th Power Plan was published.
Charlie Black	3:52 PM	Will the wholesale power price forecasts be made available at the hourly price level of granularity?
James Adcock	3:54 PM	WAC regulations require IRP *Participation* NOT *Presentation* !
Kate Maracas	3:58 PM	Riase hand -
James Adcock	3:58 PM	Slide 28 Even "just" BPA hydro modulation -- BPA choosing to generate more when prices are high, and to generate less when prices are low -- since most hydro *is* a form of stored energy -- would *in practice* greatly compress the assume high variability in this slide.
Court Olson	3:59 PM	The response to the question from Don Marsh is not satisfactory. This problem of dialogue and interaction has been long standing with PSE TAG meetings in the past and it has been worsened in the webinar format. This is not because a webinar format prevents the level of interaction that we would like and have been requesting for years. It appears to clearly be the PSE preference to have condensed meetings that are largely in presentation form. Please reconsider your response voiced today by the meeting facilitator. Many of us are not feeling that these meetings are as interactive as they should be. If more time is needed, then make a little more time available for dialogue during presentations. That should not be difficult. We'll appreciate your consideration.
Robert Briggs	4:00 PM	Two part comment on slide #28: There are vertical scale problems on this slide. There may be a lot of valuable data on the slide but they are obscured by the presentation. A log scale or other technique could solve the problem. It does appear that there are significant numbers of VERY inexpensive power. What assumptions about storage are embedded in the graph?
Kathi Scanlan	4:00 PM	In the context of the 2019 IRP Progress Report and changes compared to these 2021 draft numbers, would you discuss the three primary inputs that affect power prices and what you've seen in terms of changes in modeling and results thus far?
Kevin Jones	4:01 PM	I agree with Don re: lack of improvement in exchange of info between the public and PSE and will add (1) TAG members raised this same issue - a lack of dialogue - in the 2019 IRP. I expect that is true from years past. PSE has not solved this problem, despite the IAP2 claims, the remote engagement and the point that there are 50 people on the call, and (2) Comments in response to the 2021 PSE IRP work plan stated: "To successfully address this concern (unresolved issues), we call upon PSE to ensure strong stakeholder engagement and allow sufficient Milestone B time to successfully resolve these issues to the satisfaction of the primary stakeholders" to which PSE responded "We are going to continue to update the meeting schedule as we develop the IRP technical work and receive stakeholder feedback on the specific technical topics". I appreciate your dedication to addressing public concerns by

Name	Time sent	Comment
		allowing sufficient time for dialogue. It appears that additional IRP work plan schedule adjustments are needed.
Fred Heutte	4:08 PM	raise hand for a comment on prices
James Adcock	4:08 PM	Raise Hand
Virginia Lohr	4:08 PM	Please read my comment from 3:33, which reinforces what toehrs ahve said.
Robert Briggs	4:09 PM	I was puzzled by the comment made along with slide #26 that the 20-year low price for gas reflected delays in permitting LNG export facilities. Does this suggest that another 20 years of delays are anticipated in Kalama Methanol and Jordan Cove? Or did I mishear? In any case, it strikes me that a longer view on these prices is needed.
Alexandra Streamer	4:09 PM	To confirm, Virginia, is this the comment: "Giving PSE time to get through their presentation clearly is simply "informing." People attending these meetings are not doing so simply to be informed, but clearly want to have meaningful input into the process. There appears still to be something broken in the system when the goal is for PSE to get through their presentation. This is no change or even a back-track from the last IRP process. Your feedback requested on slide 38 seems rather simplistic given the entire slide deck."
Kevin Jones	4:10 PM	Could you explain the rationale for the position that PSE does not apply the Social Cost of Carbon to electricity that comes in from other states when PSE calculates their IRP power price?
Kevin Jones	4:19 PM	Thanks Elizabeth. I'll give that more thought and see if I have a follow-up input.
Kate Maracas	4:19 PM	Raise hand.
Don Marsh	4:23 PM	I would love to feel that PSE is making a leading-edge effort to embrace smart and modern technologies like energy storage, demand response, distributed generation, and energy efficiency. We feel that many other utilities are doing a better job in these areas. A company serving a technologically advanced and environmentally aware customer base in the Puget Sound region should be providing a great example for the whole country. Stakeholders are trying to do our part.
Don Marsh	4:23 PM	Perhaps that can be demonstrated in the CEIP?
Kevin Jones	4:24 PM	I know this meeting agenda does not include DR, but since we just completed the UTC DR Workshop, what issues and opportunities do you see for PSE to increase their adoption of DR in this IRP. I recall from the PSE SCC Workshop that little DR was adopted, leading one reviewer to say "there must be something wrong with your model". Do you think the model needs adjustment and was there any insights from the DR Workshop that suggests any specific adjustments?
Kathi Scanlan	4:24 PM	Staff appreciates that we can see all questions asked in this GoToMeeting real time. Thank you for making this change.
Alexandra Streamer	4:24 PM	@Don and @Kevin, would you like to read that out or just submitting for comment?
Kevin Jones	4:24 PM	That is a question for PSE to address.

Name	Time sent	Comment
Don Marsh	4:24 PM	You can read mine. Thanks
James Adcock	4:26 PM	If PSE "Promises" to answer my question about what their data sources into their analsyses are, and what range of historical dates that data comes from, that would be a step forward after 10 years of waiting. For example PSE just "answered" my previous question about Wind data by referring me to a 5 Terabyte database, out of which PSE only actually uses about 5 Megabytes, which means that somewhere in there literally 1 part in a Million of where PSE pointed me to, is the actual answer. So PSE's "answer" is to send me off for literally a "Find One Needle in a Million Hay Haystack" -- Is This Seriously what you call "Answering my question?"
Robert Briggs	4:27 PM	Regarding slide #35, I'm a little concerned regarding the simplistic choices we have been encourgaed to provide feedback on. If you're serious about getting feedback, it needs to be unbundled and have far more technical detail. I prefer the green line (Secenario 1), but why do we not see renewable builds until year 9? I'm confused.
Kevin Jones	4:27 PM	I look forward to that discussion My question - do you have any insights at this time?
James Adcock	4:28 PM	So Once Again -- You are not Answering My Question???
Kevin Jones	4:29 PM	Let me rephrase with more content: Thanks for your reply on DR Elizabeth. My question - did PSE receive any insights on DR from the UTC DR Workshop?
David Perk	4:29 PM	Take a deep breath, James!
James Adcock	4:29 PM	They always dodge my questions.
Kevin Jones	4:30 PM	I suggest PSE stay on for another 10 minutes to answer unanswered questions, allowing others to leave if they choose to.
Robert Briggs	4:30 PM	I second.
Kevin Jones	4:31 PM	Letting the clock take priority over public inputs is disrespectful.

PSE IRP Feedback Report
Webinar 2: Electric Price Forecast
June 10, 2020

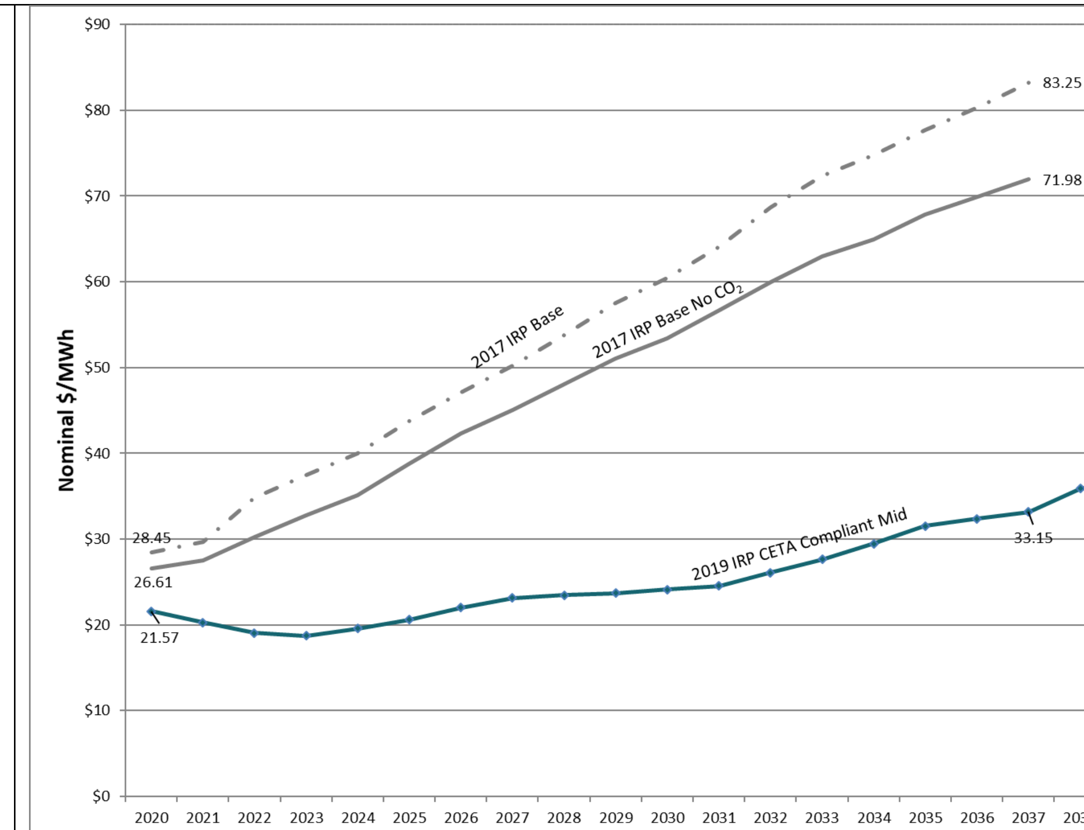
6/24/2020

The following stakeholder input was gathered through the online Feedback Form, from June 3 through June 17, 2020. PSE's response to the feedback can be found in the far right column. To understand how PSE incorporated this feedback into the 2021 IRP, read the Consultation Update, which will be released on July 1, 2020.

2021 IRP Electric Price Forecast Workshop Feedback Report			
Feedback Form Date	**Stakeholder**	**Comment**	**PSE Response**
6/4/2020	James Adcock (1)	June 10 IRP meeting Expressed Concern I am expressing a concern that the "explanation" of how PSE performs "modeling" is being presented at such a low "Kindergarten Level" as to prevent any meaningful understanding of what modeling, and how, that PSE is performing -- and this is a presentation to a "Technical" group -- and yet you are giving the explanation at only a "Kindergarten Level". By giving the presentation at a "Kindergarten Level" you are preventing meaningful participation in the PSE IRP. PSE used to give much more meaningful explanations of their modeling methods in years past -- while still being very imprecise.	PSE acknowledges your concern.
6/4/2020	James Adcock (2)	PSE should provide a detailed technical explanation of how exactly they are performing modeling, including an explanation of all historical data used in their modeling, and the range of historical dates, from earliest date to latest date, of each of those historical data records.	Thank you for your suggestions. The 2021 IRP book will include more detail than the meeting presentations.
6/4/2020	James Adcock (3)	June 10 IRP meeting Question Can you please enumerate in detail all of the various types of historical data used anywhere in any of your modeling efforts, including the earliest calendar year and latest calendar year from which each of those historical data types was used. For example, in IRP's years past PSE has explained that it uses: Temperature data from a large range of years, "Water" data (hydroelectric dam generation related data), "Wind" data -- data used to develop predictions of Wind Power performance in Washington State or other states, Load data -- actual historical patterns of electrical use by PSE customers, Gas prices, Econometric data -- historical measures of how weak or strong the regional economy has been.	PSE will share historical data ranges for temperatures, hydro data and other data when it covers the IRP topic that references the data. The assumptions for the electric price forecast were shared in the webinar and a recording of the webinar is posted on the IRP website.
6/4/2020	James Adcock (4)	June 10 IRP meeting Question Page 20 (and page 34) On this page you state "With stakeholder input..." as in: "With stakeholder input, the 2019 IRP electric price forecast assumed a renewable need of 22.9 million MWh in 2030, approximately 8,700 MW nameplate capacity of new renewable resources added in Washington state." What I remember of the "stakeholder input" in the [PSE canceled] 2019 IRP Process is that the "stakeholders" roundly disagreed with virtually everything PSE discussed or was proposing -- and in turn PSE simply canceled the 2019 IRP Process. In this context can you please explain what you mean by "With stakeholder input" -- given that I don't think PSE accepted, but rather rejected, any and all "stakeholder input" ??? Given that PSE canceled the 2019 IRP Process before it completed, I ask that PSE here and now retract the claim that these issues were developed with "stakeholder input."	PSE updated the presentation and referenced the 2019 IRP Progress Report or the 2019 IRP process instead of 2019 IRP, where appropriate. During the 2019 IRP process, stakeholders gave feedback on the level of new renewable resources assumed for Washington to meet the CETA requirement. PSE then took that feedback and adjusted the amount of new renewable resources assumed based on the feedback.
6/4/2020	James Adcock (5)	Retract the claim here and elsewhere that the "2019 IRP Process" was actually developed with "stakeholder input" -- given that PSE unilaterally decided without advanced warning and with no stakeholder input to cancel the "2019 IRP Process" before it was complete and vetted by stakeholders. Further, do not refer to the "2019 IRP" because the "2019 IRP" does not exist -- because the "2019 IRP" was unilaterally canceled by PSE before the "2019 IRP" was completed.	PSE updated the presentation and referenced the 2019 IRP Progress Report or the 2019 IRP process instead of 2019 IRP, where appropriate. We will make best efforts to ensure that appropriate references are used going forward. On October 28, 2019, the Washington Utilities and Transportation Commission Staff filed a Petition for Exemption from WAC 480-100-238 pursuant to WAC 480-07-100 until December 31, 2020. On November 7, 2019 the WUTC held an Open Meeting concerning

			this matter and subsequently issued Order 2, exempting PSE (and other investor owned utilities in Washington) from WAC 480-100-238. Pursuant to Order 2, PSE filed an IRP Progress Report on November 15, 2019. On December 10, PSE filed a Revised Progress Report, available at pse/irp.com_2019 Progress Report
6/4/2020	James Adcock (6)	June 10 IRP meeting Question Page 24 On this page you state for the "2021 IRP electric price update" that the "Regional Demand from the 7th Power Plan" didn't change. Why didn't it change? Why would you not assume a downturn in demand due to the downturn in the economy due to COVID-19? Shouldn't your regional demand assumptions be updated to recognize the reality of the huge change in the regional economy, and thereby demand, caused by COVID-19? Economists are projecting that it will take a decade for the US Economy to recover from COVID-19.	PSE uses the regional demand forecast from the Northwest Power and Conservation Council. At the time of the presentation, PSE was not able to obtain to the regional demand from the Council. PSE has made an additional request for the 7th power plan mid-term update. There will be an update in the consultation update on whether we were able to get the updated regional demand forecast and if it can be used for the 2021 IRP.
6/4/2020	James Adcock (7)	PSE should reduce the expected regional demand (relative to the 7th power plan) to fully and fairly reflect based on projections from regional and national economists of the downturn in the economy based on COVID-19, and the projected decade-long recovery it will take the economy to recover from COVID-19.	As noted above, PSE has contacted the Council for the 7th power plan mid-term update.
6/4/2020	James Adcock (8)	June 10 IRP meeting Question Page 28 You are pulling this chart "like a rabbit out of a hat" -- with no technical explanation whatsoever of how you have developed this plot, and what assumptions go into this plot. Can you please list all of the assumptions, and all of the data used, including historical range of dates from which that data was collected, in generating this plot?	The plot on slide 28 provides an overview of the hourly power prices over the entire time horizon (2022 through 2041) for the 2021 IRP. Each hour of the year is represented as a single green point on the plot. These data are the output of the Aurora Power Price model, which was run using the assumptions discussed throughout the presentation. Also provided on the plot are box and whisker charts which provide some high-level statistics about the power prices for each year (mean, median, 10th, 25th, 75th and 90th percentiles). The intended message of the plot is to show an increase in variability of power prices in the late years of the time horizon as more and more renewable resources are added to the WECC.
6/4/2020	James Adcock (9)	June 10 IRP meeting Question Page 37 Given that the 2019 IRP was canceled before it was completed, can you please delete the "2019 IRP Base" claim -- There is no "2019 IRP" because it was never completed -- because PSE chose unilaterally without consulting with stakeholders to terminate the "2019 IRP" effort before it was completed and before stakeholders had a chance to vet it, or comment on it. Since there is not "2019 IRP" there can be no "2019 IRP Base"	Thank you for your input. Going forward, PSE will make best efforts not to reference the “2019 IRP” but rather the “2019 IRP process” or the “2019 IRP Progress Report” including labels on slides.
6/4/2020	James Adcock (10)	Delete the "2019 IRP Base" claim -- There is no "2019 IRP" because it was never completed -- because PSE chose unilaterally without consulting with stakeholders to terminate the "2019 IRP" effort before it was completed and before stakeholders had a chance to vet it, or comment on it. Since there is not "2019 IRP" there can be no "2019 IRP Base."	As stated above, PSE will make best efforts not to reference the “2019 IRP” but rather the “2019 IRP process” or the “2019 IRP Progress Report”.
6/4/2020	James Adcock (11)	June 10 IRP meeting Question Page 42 Given that CETA is now "the law of the land" why is it appropriate to develop a scenario where you assume that you do not have to meet the CETA requirements? Shouldn't the range of scenarios you consider be drawn from the "legal" list of possibilities, and not contemplate running PSE in an "illegal" manner?	PSE is reviewing all the suggestions and contacting some stakeholders for further discussion. PSE will have the final list of scenarios for the July 1 consultation update.
6/4/2020	James Adcock (12)	Draw all your "scenarios" from "legal" sets of possibilities which do not contemplate running PSE in an "illegal" manner.	Thank you for your feedback. PSE is developing the 2021 IRP in compliance with all legal and regulatory requirements.
6/4/2020	James Adcock (13)	June 10 IRP meeting Question Page 19 On Page 19 you reference the "2019 IRP" but there is no "2019 IRP" because PSE chose to abruptly without warning terminate the "2019 IRP" before it was completed.	Please see our response to your comments 5 & 10.

6/4/2020	James Adcock (14)	Do not reference the "2019 IRP" because there is no "2019 IRP" -- because PSE chose unilaterally with consulting stakeholders to terminate the 2019 IRP Process before it was completed.	Please see our response to your comments 5,10 & 13.
6/10/2020	Vlad Gutman-Britten, Climate Solutions	Slide 17: Why are no thermal plants built in WA? Is this CETA or some other constraint? It again reads like SCC is only applied to plants in Washington and not outside of it, which isn't in keeping with the requirements of CETA or the previous UTC acknowledgement letter. Slide 19: There are other extant policies/commitments that should be included—Xcel has committed to 100% clean by 2050, Idaho Power and Avista have both made the same commitment. A number of CO laws also matter here: Colorado utilities must consider SCC in planning and the PUC must make progress toward 90% carbon reduction by 2050. These will impact resource choices and price forecasts. Slide 20: For the utilities below 80%, these are likely to somewhat overcomply with the 2030 requirement in order to address variability in hydro. It could be worth modeling actual compliance strategies as this will yield a different mix of renewables and thus impact price forecasts. Slide 21: Assumption shouldn't be no new renewable energy investments until 2028. Considering only state-wide RE need doesn't reflect how utilities, especially investor-owned utilities, will comply. Slide 22: Would like to see the 2017 with high CO2 comparison since the 2019 does have CO2 included. Slide 29: why did price increase on this slide when on slide 27 it appears to have declined slightly? Slide 34: A little confused on the difference between the two scenarios with CA/WA; shouldn't frame CA 2045 law as a "goal"; CA 2030 requirement is RPS only, not carbon-free. Slide 42: Scenario #3 should have a higher CO2 price, going beyond what is required by law for the "high scenario." Scenario #4 appears to be a baseline comparison, and should include CETA but not the clean energy standards.	Slide 17: Given that PSE is modeling the entire region as a whole, the model assumes that there is plenty of resources in the region given normal hydro conditions and mid load. This is different than the PSE portfolio model, where PSE is accounting for transmission constraints into the PSE service territory. So even though there might be enough resources in the region, it may not be delivered to load due to transmission constraints. To reflect the social cost of carbon planning adder in PSE's portfolio model, market purchases will include a wheeling cost equivalent to the SCC adder during the capacity expansion run. Slide 19: PSE has elected not to include corporate or non-binding policies into the Power Price model due to lack of accountability of these policies and difficulty in modeling numerous policies at the balancing authority resolution. Slide 20: Thank you for the suggestion, however, PSE is unable to incorporate actual clean energy adoption strategies into the modeling process due to lack of insight into the resource acquisition strategies of each Washington utility. Therefore, PSE has elected to model either the 80% clean energy implementation required by CETA or a generic more aggressive (~90%) clean energy implementation for the 2021 IRP. Slide 21: Thank you for the suggestion, PSE is updating the assumption and will have the updated targets for the July 1 consultation update. Slide 22: Below is the updated chart which includes the 2017 IRP Base power price:



Slide 29: Slide 27 shows the annual, nominal power price for the 2019 IRP process and draft 2021 IRP power price. Slide 29 shows the levelized power price over the timeframe for each IRP process, which incorporates the time value of money (net present value). Each slide is an NPV over different time periods which is why they are slightly different.

Slide 34: CA SB 100, Chapter 312

SEC. 5.

Section 454.53 is added to the Public Utilities Code, to read:

454.53.

(a) It is the policy of the state that eligible renewable energy resources and zero-carbon resources supply 100 percent of all retail sales of electricity to California end-use customers and 100 percent of electricity procured to serve all state agencies by December 31, 2045. The achievement of this policy for California shall not increase carbon emissions elsewhere in the western grid and shall not allow resource shuffling. The commission and Energy Commission, in consultation with the State Air Resources Board, shall take steps to ensure that a transition to a zero-carbon electric system for the State of California does not cause or contribute to greenhouse gas emissions increases elsewhere in the western grid, and is undertaken in a manner consistent with clause 3 of Section 8 of Article I of the United States Constitution. The commission, the Energy Commission, the State Air Resources Board, and all other state agencies shall incorporate this policy into all relevant planning.

			California law states that zero-carbon resources will supply 100% of sales by 2045, so it does not have to be met by all renewable resources, other carbon-free resources can be used. Slide 42: Thank you for your feedback on the scenarios. PSE is reviewing through all the suggestions and getting in contact with some stakeholders for further discussion. PSE will have the final list of scenarios for the consultation update.
6/10/2020	James Adcock (15)	In these times, and with the extremely limited amount of time PSE is setting aside from their Presentations to allow actual Stakeholder Participation, telling stakeholders, who are adult professionals, how they ought to live their lives in order to reduce stress and health effects, seems particularly inappropriate. In the same spirit, let me offer PSE a few "safety suggestions" on things PSE could do to "reduce stress" (below) 1) PSE should make sure that trench retention devices are always actually in place before an employee or contractor climbs into a trench so that person will not get killed. 2) 3) PSE should make sure that employees or subcontractors in the field are actually wearing masks, and/or maintaining 6 feet of distance from each other -- because they are not doing so. It is stressful for us to see that PSE is in practice spreading COVID-19. 4) PSE can actually substantially reduce their CO_2e emissions now, in order to reduce our stress that we will not actually have a planet for our children and grandchildren to live safely and healthily upon.	It is a PSE corporate policy to include a Safety Moment in meetings with more than 5 people. PSE regrets that you found our Safety Moment inappropriate, it was provided with the best intentions.
6/10/2020	James Adcock (16)	One thing that greatly saddens me with the current choice of format -- where stakeholders have to type their input into a chat box -- is that it makes it virtually impossible to "hear" the input from other stakeholders -- in that I am trying to listen to the PSE presenter, read the PSE slide, while at the same time read stakeholder feedback in the chat box -- and while trying to type my own feedback or questions into the chat box. And doing all of these half dozen things at the same time is literally impossible. Which means in practice that I do not get to "hear" the input from the other stakeholders as the PSE presentation is being made. Again, the WAC IRP requirements are for Stakeholder Participation NOT "PSE Presents while Stakeholders Listen." Change the meeting format back to something more similar to previous years' IRPs where stakeholders are directly allowed to ask questions and clarification using their voices, so that other stakeholders can literally hear what they are saying -- not just hear what PSE is saying! Again, the "raised hand" followed by microphone-speech format used in PSE in previous years, and has been used recently online by both Commerce and UTC, works perfectly fine.	PSE agrees that having these meeting remote is challenging and acknowledge your frustrations. We are experimenting with different platforms to identify the best tool for these meetings. The May 28 meeting was conducted on GoToWebinar. The June 10 meeting was conducted on GoToMeeting. On June 17, a survey was sent to stakeholders to gather feedback on the meeting experience to date. The June 20 meeting will be conducted on Zoom. Our preference is to select the best tool for all the meetings and be consistent through the remainder of the process.
6/11/2020	James Adcock (17)	Draft WAC 480-100-650(2) requires that utilities adaptively manage their planning and investment activities: "Each utility must continuously review and update as appropriate its planning and investment activities to adapt to changing market conditions and developing technologies" At the June 10 2020 IRP Meeting PSE stated that they do not do so. For example, PSE uses unmodified the 7th Power Plan regional load estimates, even though those load estimates were developed starting in 2010, published in 2016, and do not include the effects of the COVID-19 Economic Crash of 2020. It is well-known from past economic crashes -- and basic econometric studies -- that economic crashes reduce electricity demand, and that electricity demand does not recover until the economy recovers. National economists estimate that it will take a decade for the economy to fully recover from the COVID-19 crash, meaning that predicted electrical load growth path will not fully recover for a decade. PSE must actually update their future load forecasts, including modifying their use of the 7th Power Plan estimates, to fully and fairly reflect the on-going reductions in load (relative to the no-COVID-19 crash condition) that can reasonably be expected from the COVID-19 economic crash. Further, PSE must update their planning to include developed and developing technologies in the Wind Power field over the last 20 years. My understanding is that PSE is still doing Wind modeling based on the assumption of a Vestas V90 Wind Turbine design. This design is now 20 years old. The Wind Industry has progressed in the last 20 years, providing higher hub heights for greater wind availability, longer blade lengths to extract more power, customized blade shapes to optimize availability to lower wind speeds as found in Washington State, and optimized higher generator power in high wind speeds, such as found in Montana.	As noted above, PSE has contacted the Council for the 7th power plan mid-term update demand forecast. As noted in the feedback report from the generic resource costs webinar, PSE is using the power curve for a GE3.03-140 as a model turbine

<table>
<tr>
<td>6/17/2020</td>
<td>Willard Westre, Union of Concerned Scientists</td>
<td>Question 1) Since the renewable percentage will be determined for all power delivered by PSE, how does PSE intend to control the renewable content of the portion coming from the Mid-C market?

Question 2) What is the recent renewable percentage data of previous PSE Mid-C purchased power?

Question 3) How is that determined?</td>
<td>1. The assumptions on how PSE will treat unspecified system purchases to meet PSE load will be addressed in the July 21 webinar on social cost of carbon.
2. PSE’s recent renewable percentage data of unspecified market purchases based on the 2018 Washington State Electric Utility Fuel Mix Disclosure Reports is 61% renewable. Link to the 2018 Washington State Electric Utility Fuel Mix Disclosure Reports: https://www.commerce.wa.gov/wp-content/uploads/2020/04/Energy-Fuel-Mix-Disclosure-2018.pdf
3. PSE used the Northwest Power Pool Fuel Mix percentage provided by the Department of Commerce in mid-September of 2019 to determine the allocation for unspecified market purchases. The fuel mix percentage by category is multiplied by the total unspecified purchases of 4,352,868 MWhs reported for 2018. The percent allocated MWhs for all renewables were added together and calculated as a percent of total to determine the 61% value.

PSE's unspecified purchases for 2018* 4,352,868

<table>
<tr><th>Report Year</th><th>Fuel Category</th><th>Northwest Power Pool (NWPP) Fuel Category Percentage**</th><th>Renewable MWhs</th></tr>
<tr><td>2018</td><td>Biogas</td><td>0.23%</td><td>10,012</td></tr>
<tr><td>2018</td><td>Biomass</td><td>0.74%</td><td>32,211</td></tr>
<tr><td>2018</td><td>Coal</td><td>23.18%</td><td></td></tr>
<tr><td>2018</td><td>Geothermal</td><td>1.01%</td><td>43,964</td></tr>
<tr><td>2018</td><td>Hydro</td><td>46.30%</td><td>2,015,378</td></tr>
<tr><td>2018</td><td>Natural Gas</td><td>15.43%</td><td></td></tr>
<tr><td>2018</td><td>Nuclear</td><td>3.25%</td><td>141,468</td></tr>
<tr><td>2018</td><td>Other Biogenic</td><td>0.05%</td><td>2,176</td></tr>
<tr><td>2018</td><td>Other Non-Biogenic</td><td>0.40%</td><td>17,411</td></tr>
<tr><td>2018</td><td>Petroleum</td><td>0.18%</td><td></td></tr>
<tr><td>2018</td><td>Solar</td><td>1.14%</td><td>49,623</td></tr>
<tr><td>2018</td><td>Waste</td><td>0.03%</td><td>1,306</td></tr>
<tr><td>2018</td><td>Wind</td><td>8.06%</td><td>350,841</td></tr>
<tr><td></td><td>Total</td><td>100.0%</td><td>2,664,391</td></tr>
<tr><td></td><td></td><td>% of Total</td><td>61%</td></tr>
</table>
Notes:
*PSE's unspecified market purchases reported in the 2018 WA Fuel Mix Report is 4,352,868 MWhs
Link to the 2018 Washington State Electric Utility Fuel Mix Disclosure Reports: https://www.commerce.wa.gov/wp-content/uploads/2020/04/Energy-Fuel-Mix-Disclosure-2018.pdf
The 2019 Fuel Mix Report won't be available until Q4 of 2020.
**Northwest Power Pool Fuel Mix as provided by the Department of Commerce in mid-September 2019</td>
</tr>
<tr>
<td>6/17/2020</td>
<td>Willard Westre, Union of</td>
<td>Slide 21 showing renewable energy needed in WA is interesting but does not define the amount of renewable energy needed by PSE. Although the Process Timeline shows “Establish Resource Need” by September, apparently, neither of the remaining topics on the</td>
<td>Updated meeting schedule is currently under development and will be made available by the June 30 webinar.</td>
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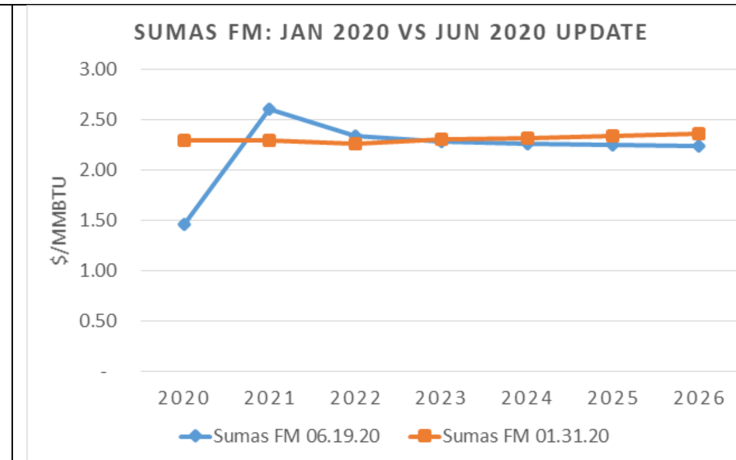
	Concerned Scientists	schedule does that. There is no session for Demand Forecast. When will the discussion on the real new renewable resources need be addressed?	
6/17/2020	Bill Pascoe, Absaroka Energy and Orion Renewables	I am requesting an electric price forecast scenario with a WECC-wide carbon tax equal to the social cost of carbon.	Thank you for your feedback on the scenarios. PSE is reviewing through all the suggestions and getting in contact with some stakeholders for further discussion. PSE will have the final list of scenarios for the consultation update.
6/17/2020	Katie Ware, Renewable Northwest	Slide 34 — RNW suggests PSE should consider how Scenario 1 and Scenario 2 would affect CETA's incremental cost of compliance calculation, and based on the results, consider which scenario would have a better chance of achieving the GHG neutral standard across WA utilities. Slide 43 — Stakeholder feedback scenarios: MID/MID and HIGH/HIGH scenarios studied with the SCC applied as an adder WECC-wide during dispatch.	Slide 34: Thank you for your feedback, PSE will be using Scenario 1 for the clean energy implementation. Slide 43: Thank you for your feedback on the scenarios. PSE is reviewing through all the suggestions and getting in contact with some stakeholders for further discussion. PSE will have the final list of scenarios for the consultation update.
6/17/2020	Kathi Scanlan, WUTC	1) This feedback, dated June 17, 2020, states the informal comments, questions, and recommendations of Washington Utilities and Transportation Commission Staff. Timely feedback is offered as technical assistance and is not intended as legal advice. Staff reserves the right to amend these opinions should circumstances change or additional information be brought to our attention. Staff opinions are not binding on the commission. 2) Slide 17 – Social cost of greenhouse gas methodology as a planning adder in the electric price forecast: a. PSE explains this cost is added for any thermal builds in Washington (tons c02*SCC($/ton) = emission cost ($), where the emission cost is then applied back to the fixed cost of thermal plants in Washington. Please further clarify, is this energy delivered to Washington? Are these thermal units that are built in, and physically located in, Washington? b. Please explain why this methodology is appropriate for the electric price forecast in the context of the Clean Energy Transformation Act (CETA) requirements. 3) Slides 37-38, 42 – Scenario Development and CETA. The two scenarios where the Washington renewable requirement is modeled at 80 vs. 90% creates a difference in Mid-C price during the mid-term but eventually converges, since both scenarios go to 100%. PSE seeks feedback on the higher and lower scenario: a. Staff generally agrees a 90% estimate could be a more reasonable (and conservative) assumption given hydro-heavy utilities in the state. b. No CETA Scenario - Staff requests more information on the assumptions that create the future conditions regarding "No CETA". Does PSE anticipate using this scenario as the baseline for calculating the incremental cost of compliance, per RCW 19.405.060(3)? If yes, we recommend refining the name of the scenario. Although No CETA is easy shorthand, it is not accurate for describing the incremental cost baseline, as the baseline should include the other elements of CETA other than RCW 19.405.040 and 050. Further clarification on this scenario would be helpful. 4) Slide 24 – What did not change since the 2019 Progress Report? And what changed? a. PSE states it intends to use, "regional demand from the 7th Power Plan". Why? b. Is PSE planning to update its regional demand inputs? The Seventh Power Plan Midterm Assessment has updated regional data, which is available, and can provide more recent inputs: https://www.nwcouncil.org/sites/default/files/7th%20Plan%20Midterm%20Assessment%20Final%20Cncl%20Doc%20%232019-3.pdf 5) Slide 25 – Gas Price Forecast: a. What is the date of the Fall 2019 Wood Mackenzie report that PSE is relying on for the 2021 IRP, and is this PSE's most up-to-date Wood Mackenzie gas price forecast report? b. Given the significant unforeseen changes to the economy since March 2020, is it possible to go back to Wood MacKenzie and request a more recent update? 6) Slides 37 & 42 - California and BC Assumptions:	1. Thank you and noted. 2. Social cost of carbon as a planning adder a. The social cost of carbon is an adder to thermal plants physically located in Washington. Since Washington state is a part of the Mid-C market along with Oregon, Idaho and western Montana, PSE cannot separate out Washington state from the rest of the Mid-C and therefore unable to determine where the energy is being delivered to. The assumptions on how PSE will treat unspecified system purchases to meet PSE load will be addressed in the July 21 webinar on social cost of carbon. b. Instructions on how to incorporate the SCC are provided by the Clean Energy Transformation Act (CETA). The references to the SCC in CETA are provided below: *"(3) (a) An electric utility shall consider the social cost of greenhouse gas emissions, as determined by the commission for investor-owned utilities pursuant to section of this act and the department for consumer-owned utilities, when developing integrated resource plans and clean energy action plans. An electric utility must incorporate the social cost of greenhouse gas emissions as a* **cost adder** *when:* *(i) Evaluating and selecting conservation policies, programs, and targets;* *(ii) Developing integrated resource plans and clean energy action plans; and * *(iii) Evaluating and selecting intermediate term and long-term resource options. p. 33 E2SSB 5116.S*

		a. Staff requests more clarification on how PSE is modeling California renewables; it is not clear regarding the ramp between 60% and 100%. Will it be at ~80 percent in 2030? b. What C02 price is applied for CA AB32 and BC? 7) Other questions regarding PSE's social cost of greenhouse gas emissions modeling: a. PSE explains the methodology will be discussed at a later July 21 webinar. Does PSE plan to model SCC applied to thermal power imports into WA? b. It is staff's understanding in Aurora a "wheeling adder" can be added for imports into California, which is then used to capture the cost of carbon imports. Is this approach also appropriate for Washington to model the social cost adder of greenhouse gas emissions for imports?	*(b) For the purposes of this subsection (3):* *(i) Gas consisting largely of methane and other hydrocarbons derived from the decomposition of organic material in landfills, wastewater treatment facilities, and anaerobic digesters must be considered a non-emitting resource; and* *(ii) Qualified biomass energy must be considered a non-emitting resource."* ***Section 14, Page 33*** The legislation explicitly instructs utilities to use the SCC as a cost adder when evaluating conservation efforts, developing IRPs and CEAPs, and evaluating resources options. PSE understands this "cost adder" to mean that the SCC is included in planning decisions, but not in the actual cost and dispatch of any resource that it is applied to. 3.a. Thank you for your feedback, PSE will be using Scenario 1 for the clean energy implementation. b. Thank you for your feedback on the scenarios. PSE is reviewing through all the suggestions and getting in contact with some stakeholders for further discussion. PSE will have the final list of scenarios for the consultation update. 4. PSE has contacted the Northwest Power and Conservation Council to request for the 7th power plan mid-term update. There will be an update in the consultation update on whether we were able to get the demand forecast and if it is usable for the 2021 IRP. 5. The Wood Mackenzie gas price forecast is from fall 2019. This is the most recent forecast for Wood Mackenzie, the update forecast will not be ready for several weeks. However, PSE can update the foreword marks through 2026. The updated foreword marks (blue line) is the 3-month average ending June 30, 2020. As seen in the chart, the 2020 costs are much lower than the January 31 estimate and then the 2021 costs are higher during the current economic recovery. However the prices return back to January estimate by 2022 and continue to match closely through 2026. Since the time horizon for the 2021 IRP starts in 2022, this update will not have much of an impact.



6.

a. The California SB100 requires 60% renewable resources by 2030, so PSE is modeling 60% by 2030 and then ramping into 100% by 2045.

b. Below is the assumed CO2 price in Aurora for the state of California:

Year	Aurora Default carbon emission price for California's carbon cap-and-trade program (2012$)
2022	15.13
2023	15.89
2024	16.69
2025	17.52
2026	18.40
2027	19.32
2028	20.28
2029	21.30
2030	22.36
2031	22.36
2032	22.36
2033	22.36
2034	22.36
2035	22.36
2036	22.36
2037	22.36
2038	22.36
2039	22.36
2040	23.16
2041	24.06
2042	24.96
2043	25.86

			<table><tr><td>2044</td><td>26.76</td></tr><tr><td>2045</td><td>27.66</td></tr></table> Currently, there is no assumed CO2 price for BC. PSE will make this correction to the Aurora model. 7. a. PSE will discuss how the social cost of carbon is applied to PSE's portfolio model in the July 21 webinar and will be happy to answer additional questions then. b. This relates back to 2a. If Washington was a separate zone, PSE could apply a wheeling cost to market purchases heading into Washington. However, Washington has been combined with Oregon, Idaho, and Western Montana to create the Mid-C zone, making it difficult to separate Washington.
6/17/2020	Joni Bosh, NWEC	Questions on Feedback session #2 Resource Costs Slide 11 – • Under IRP: Does the electric price forecast for economic dispatch of power plants used in modeling "to support resource acquisitions" include the Social Cost of Greenhouse gases? What is the value used for SCGHG? • Under Avoided Cost: Please illustrate/explain how the price forecast is used to develop avoided costs for EES and PURPA. • Resource acquisitions: Clarify what steps PSE takes and which model(s) it uses in the resource acquisition analysis. Slide 17 – • Emissions costs are operating costs, not fixed costs. Please explain why the SCGHG emission costs in step three of the Aurora modeling is added back to the fixed costs of thermal plants? Slide 20 – • Explain how elements relating to statewide renewable need on slide 20 and the outcomes on slide 21 are incorporated in the price forecast. Slide 22 – • Please express the results in this chart in real dollar terms as well. NWEC urges PSE to include real dollar results along with the nominal dollar results at least for summary tables and charts throughout the IRP. This will help improve comparability across different analyses and time horizons. Slide 24 – • By using 80 years of observational weather data as is incorporated in the Regional Demand from the 7th Power Plan (the data which is now at least five years old), future climate impacts on load are not adequately represented. PSE should review the Council's climate adjusted demand forecast when it becomes available to compare the impact on energy price forecasts. Slides 25 and 26 – • PSE should add a sensitivity using a high gas price that is 25% more than the baseline price, to reflect the risk from the reality of reduced gas production in North America. Slide 29 • Please also show this chart in discounted present value levelized dollars. Slide 34 –	Slide 11: a. Yes, the electric prices include SCGHG as a planning adder. PSE is using the SCGHG value identified in SB5116 and updated to include inflation as released by the Washington UTC. b. The price forecast is the avoided cost of energy used in the avoided costs for EES and PURPA. A complete write-up of the methodology can be found in dockets UE-190665 and UE-191062 c. The resources acquisition process uses all the same models as the IRP. The IRP sets the power prices using the AURORA power price model and then sets the peak capacity need using the Resource Adequacy model and also does the flexibility analysis using the Plexos model. Both the RA model and Plexos model are updated with the resources bid through the acquisitions and then tested in the portfolio model. Slide 17: See reply to Kathi Scanlan, WUTC, question number 2. The law states that the SCGHG is a "cost adder" not a dispatch cost and therefore it follows the methodology described. Slide 20: Renewable need is forced into Capacity Expansion as a must-build resource, so the model builds enough renewable resource to meet renewable constraints, see slide 33. Slide 22: As part of the Webinar #2: Power Price Forecast Consultation Update (to be released on 07/01/2020), PSE will provide a spreadsheet (Excel workbook) with the final 2021 IRP power price scenarios. PSE will include a conversion tool from nominal to real dollars as part of this spreadsheet. Slide 24: The Council's updated demand forecast is not ready for release yet and PSE has reached out to the Council regarding the mid-term update. Slide 25 and 26: Thank you for your feedback on the scenarios. PSE is reviewing through all the suggestions and getting in contact with some stakeholders for further discussion. PSE will have the final list of scenarios for the consultation update. Slide 29: As part of the Webinar #2: Power Price Forecast Consultation Update (to be released on 07/01/2020), PSE will provide a spreadsheet (Excel workbook) with the final 2021 IRP power price scenarios. PSE will include a conversion tool from nominal to real dollars as part of this spreadsheet.

		• Please explain these two scenarios and the assumptions behind implementation scenarios 1 and 2. We are not able to advise on the question posed on slide 38 without a better understanding of the two scenarios. Slide 38 – • We would appreciate PSE explaining the pros and cons of the options posed on this slide. The context of this question is unclear. Slide 42 and 43 – • What is the purpose of including a No CETA scenario? • We would like to see a low demand/high gas price scenario.	Slide 34: PSE has contacted Joni for further discussion. Since Joni is unavailable until early July, PSE will meet with Fred Huette from NWEC in her place. Slide 38: PSE will meet with Fred Huette to clarify the slide and help with any confusion related to the stakeholder feedback. Slide 42 and 43: Thank you for your feedback on the scenarios. PSE is reviewing through all the suggestions and getting in contact with some stakeholders for further discussion. PSE will have the final list of scenarios for the consultation update.

6/17/2020	Vlad Gutman-Britten, Climate Solutions	- Social Cost of Greenhouse Gas Application (Slide 17)
		  - Why does this apply to the electric price forecast, rather than just in the portfolio model? If the SCGHG is applied during portfolio modeling at the end, it would appear to double count the SCGHG by also including it upfront in the electric price forecast. Because SCGHG is an adder, it will not actually impact market prices. We believe that IRP modeling should reflect reality to the extent possible, and so SCGHG should be accounted for post-economic dispatch in order to evaluate competing resource portfolios as they would function in the real world.
		  - However, if PSE does continue to apply the SCGHG in developing the electric price forecast, it is still unclear why the SCGHG is only applied to Washington resources. While we understand that this is a cost adder, the cost adder in CETA does not only apply to facilities physically located in Washington, but rather to any energy delivered to Washington customers, regardless of the point of generation. Given that PSE can model the specific cost adders of California and British Columbia, why is it not possible to apply the SCGHG adder to all electricity being delivered to Washington customers?
		  - PSE noted in the slide that there are no new thermal builds in Washington. It was unclear during the presentation whether this was a modeling constraint based on the assumption that CETA would prevent new thermal builds in Washington, or due to another underlying assumption. If it is a result of the former, this appears out of step with previous PSE model runs and projections.
		
		- Renewable Resource need in WA (Slide 21)
		  - While CETA does not have any firm requirements until 2030, the law does require that utilities demonstrate continuous progress towards achieving the GHG neutral and 100% requirements of CETA. This slide pertains to all resource needs in Washington for compliance with the act--if utilities make progress towards the law between 2022-2030, we anticipate the glide path beginning in earlier years and potentially having an impact on the electric price forecast.
		
		- Stakeholder feedback (Slide 38):
		  - Assumptions on WA/CA compliance: We appreciate the two end cases, reflecting various compliance scenarios for Washington and California. While both provide useful information, we can anticipate compliance will fall in between the two end cases for Washington. Washington utilities already serving load with more than 80% nonemitting and renewable resources will still be required to demonstrate progress towards achieving the GHG neutral standard, but may fall short of achieving 100% clean energy by 2030. Some utilities in Washington currently serving load with less than 80% clean energy may choose to somewhat overcomply to mitigate for hydro variability. In California, while utilities have some flexibility in how to meet the requirements of the law, we do not expect new large investments in nonemitting resources (nuclear), and the state's one remaining nuclear plant is scheduled to retire in the mid-2020s. It would be a reasonable assumption that California will continue receiving nuclear energy from other nuclear facilities, principally Palo Verde Nuclear Generating Station which represents about 3% of current load, but serve all new resource needs with 100% renewable energy, including renewable natural gas, synthetic gas, and hydropower.
		
		  - Consistency: We recommend consistent application of the clean energy regulation in order to compare the results. However, we do recommend running sensitivities on the end-cases in order to see how results may change.
		
		- Drat scenarios (Slide 42)
			Slide 17:
			a. Thank you for your feedback. PSE agrees that the SCGHG should be accounted for post-economic dispatch and the method that PSE created does this.
			b. The social cost of carbon is an adder to thermal plants physically located in Washington. Since Washington state is a part of the Mid-C market along with Oregon, Idaho and western Montana, PSE cannot separate out Washington state from the rest of the Mid-C at this point and therefore unable to determine where the energy is being delivered to. The assumptions on how PSE will treat unspecified system purchases to meet PSE load will be addressed in the July 21 webinar on social cost of carbon.
			c. This relates back to part b of this question. Given that PSE is modeling the entire region as a whole, the model believes that there is plenty of resources in the region given normal hydro conditions and mid load. This is different than the PSE portfolio model, where PSE is accounting for transmission constraints into the PSE service territory. So even though there might be enough resources in the region, it may not be delivered to load due to transmission constraints. To reflect the social cost of carbon planning adder in PSE's portfolio model, market purchases will include a wheeling costs equivalent to the SCC adder during the capacity expansion run.
			
			Slide 21: Thank you for the suggestion, PSE is updating the assumption and will have the updated targets for the July 1 consultation update.
			
			Slide 38: Thank you for your feedback, PSE will be using Scenario 1 (90%) for the clean energy implementation.
			
			Slide 42 and 43: Thank you for your feedback on the scenarios. PSE is reviewing through all the suggestions and getting in contact with some stakeholders for further discussion. PSE will have the final list of scenarios for the consultation update.
			
			At this point, PSE is only modeling clean energy and RPS laws and the current law is Oregon is to reach 50% by 2030.

		- The "High" scenario includes high demand and a high gas price, but does not include a higher SCGHG. While CETA requires SCGHG as a minimum cost adder, that cost may still be an underestimate and PSE should reflect the risk of a higher emissions cost in the high scenario. - The "No CETA" scenario would provide useful information for the alternative lowest reasonable cost scenario for comparison with the compliance scenario. However, the incremental cost cap is based only on compliance with the GHG neutral and 100% Clean Energy Standards. The "No CETA" scenario should be renamed "Non compliance scenario" and should incorporate other components of CETA beyond the clean energy standards into the lowest reasonable cost. - Stakeholder feedback (Slide 43) - Additional electric price scenarios: - Low demand to reflect a recession, high gas prices to incorporate greater risks of reliance on fossil fuels, and compliance with all laws - Addition of a 100% clean electricity requirement consistent with CETA in Oregon. - Passage of a carbon price for all Washington consumed electricity starting at $15/ton beginning in 2022.	

PSE IRP Consultation Update
Webinar 2: Electric Price Forecast
June 10, 2020

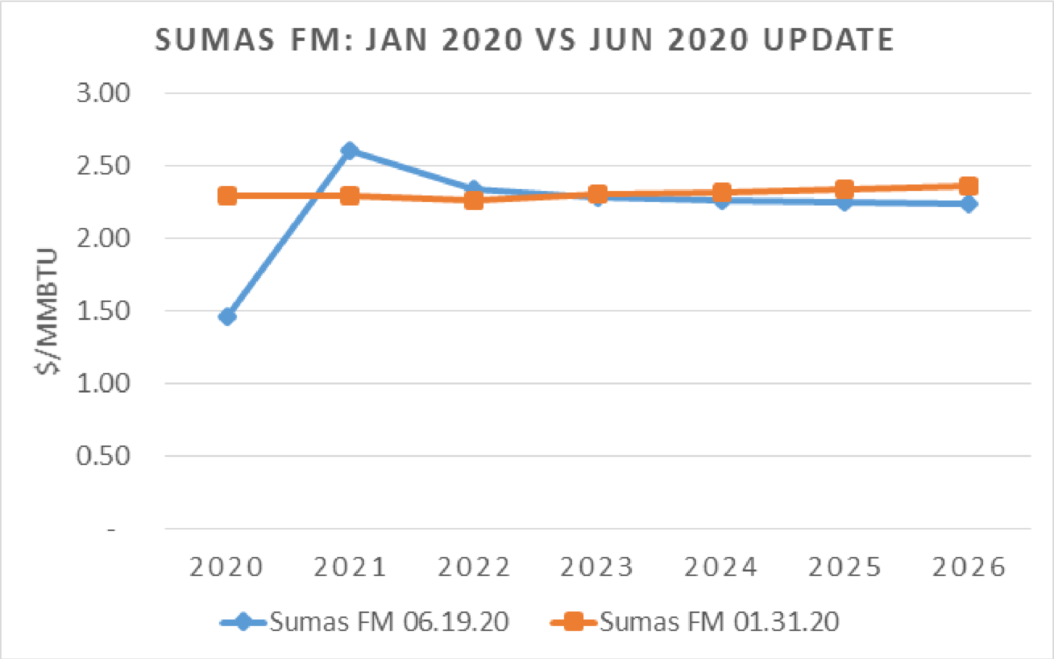
7/1/2020

The following consultation update is the result of stakeholder suggestions gathered through an online Feedback Form, collected between June 4 through June 17, 2020 and summarized in the June 24 Feedback Report. The report themes have been summarized and along with a response to the suggestions that have been implemented. If a suggestion was not implemented, the reason is provided.

PSE also thanks Fred Huette of Northwest Energy Coalition (NWEC), Vlad Gutman-Britten of Climate Solutions, Bill Pascoe of Pascoe Energy representing Absoroka Energy & Orion Renewables and Katie Ware of Renewables Northwest for meeting with PSE staff to help further clarify their questions and suggestions in follow-up meetings.

Gas price forecast

PSE received feedback from Kathi Scanlan, Washington Utilities and Transportation Commission (WUTC) Staff, requesting the use of an updated gas price forecast to reflect the socioeconomic changes of the COVID-19 pandemic. The PSE gas price forecast is an amalgam of two price forecasts incorporating forward marks for the short-term forecast (5 years in the future) and a Wood Mackenzie forecast for the long-term forecast (greater than 5 years into the future). PSE has updated the forward marks portion of the forecast as reflected on the chart below. The chart compares the January 2020 and June 2020 gas forward marks forecast for the Sumas hub. The chart shows a significant drop in prices in year 2020 and a slight increase in prices for year 2021, and a very similar projection in years 2022 through 2026. Given the 2021 IRP timeframe extends from 2022 to 2045, PSE does not anticipate the change in forward marks prices to have a meaningful impact on the power price forecast.



PSE has contacted Wood Mackenzie for an updated long-term gas price forecast and was informed the forecast would be released in the coming weeks. PSE will examine the magnitude of change of the updated long-term gas price forecast and, if deemed significant, incorporate the new forecast into the power price model. Further details will be provided upon receipt and analysis of the new long-term gas price forecast.

Regional demand forecast

PSE received feedback from James Adcock, Kathi Scanlan, WUTC Staff, and Joni Bosh and Fred Heutte, NWEC, concerning PSE's use of the Northwest Power and Conservation Council's (the Council) 7th Power Plan regional demand forecast. Since the 7th Power Plan was published in 2016, concerns were raised about the applicability of the regional demand forecast for PSE's 2021 IRP power price forecast. PSE has contacted the Council to request an updated demand forecast. The Council responded that the regional demand forecast intended for use in the 2021 Power Plan is not available for release at this time. However, the Council was able to provide the regional demand forecast used in the 2019 Update of the 7th Power Plan.

PSE is currently reviewing the "2019 Update" regional demand forecast and intends to incorporate the updated information into the 2021 IRP power price forecast. Further details will be provided upon analysis of the updated regional demand forecast.

Renewable need

On slide 38 of the Draft Electric Price Forecast presentation, PSE solicited feedback on how to model Washington State's renewable need. Two scenarios were presented: 22.9 million MWh by 2030 which equates to 90% adoption of renewable resources (Scenario 1) and 12.2 million MWh by 2030 which equates to 80% adoption of renewable resources (Scenario 2).

PSE received feedback from Vlad Gutman-Britten, Climate Solutions, Katie Ware, Renewable Northwest, Kathi Scanlan, WUTC Staff, and Joni Bosh and Fred Heutte, NWEC, on this topic. The majority of stakeholders suggested that PSE move forward with modeling Scenario 1 (higher renewable resource implementation in 2030) for the 2021 power price forecast.

PSE received feedback from Vlad Gutman-Britten, Climate Solutions, and James Adcock regarding the starting point for the ramp used for Washington state CETA requirements, as shown on slide 21. The renewable need will be updated with the demand forecast and an adjusted starting point for the renewable need ramp to start at the existing amount of non-emitting/renewable resources in 2022 and then ramp to the 2030 need. The ramp rate and demand forecast will be updated and further details will be provided upon completion of this analysis alongside other updates to gas price forecast and regional demand forecast discussed above.

Electric price forecast scenario selection

On slide 43 of the Draft Electric Price Forecast presentation, PSE solicited feedback on power price scenarios to include as part of the 2021 IRP. PSE received feedback from Vlad Gutman-Britten, Climate Solutions, Katie Ware, Renewable Northwest, Bill Pascoe representing Absaroka Energy & Orion Renewables, Kathi Scanlan, WUTC Staff, and Joni Bosh and Fred Heutte of NWEC on this topic. The table on the next page summarizes the stakeholder suggestions for power price forecast scenarios.

In the table, cells highlighted orange represent a change from Scenario 1 and dark grey cells represent scenarios proposed by stakeholders but will not be included in the 2021 IRP. The ‘Comments’ column provides an explanation of how the scenario may be applied in the 2021 IRP. The 2021 IRP Scenarios will include Scenarios 1, 2, 3, 6, 9, 10, 11, and 12.

2021 IRP Power Price Forecast Scenarios

	Scenario Name & Requestor	Demand	Gas Price	CO_2 Price/Regulation	RPS/Clean Energy Regulation	Comments
1	Mid	Mid	Mid	CO_2 Regulation: Social cost of carbon included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC	2021 IRP Scenario
2	Low	Low	Low	CO_2 Regulation: Social cost of carbon included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC	2021 IRP Scenario
3	High	High	High	CO_2 Regulation: Social cost of carbon included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC	2021 IRP Scenario
4	High + High CO_2 Price (Vlad Gutman-Britten, Climate Solutions)	High	High	CO_2 Regulation: High Social cost of carbon included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC	PSE recognizes the value in modeling a 'very high cost of carbon'. However, this model run is better suited as a *sensitivity* on the existing High Scenario (Scenario 3) than as a standalone scenario.
5	WECC Wide CO_2 Price (Bill Pascoe, Absaroka Energy & Orion Renewables)	Mid	Mid	WECC wide CO_2 price (federal tax)	Washington CETA, plus all regional RPS regulations in the WECC	Given the similarity to Scenario 6, PSE has elected to combine the essence of this suggestion into the modeling of Scenario 6, which also incorporates a CO_2 tax across the WECC.
6	Mid + CO_2 Tax (Katie Ware, Renewable Northwest and Vlad Gutman-Britten, Climate Solutions)	Mid	Mid	WECC wide CO_2 price (federal tax)	Washington CETA, plus all regional RPS regulations in the WECC	2021 IRP scenario where the cost of carbon is modeled as a tax instead of a cost adder. The cost will extend across the entire WECC as if by federal mandate. The cost is yet to be determined.
7	High + CO_2 Tax (Katie Ware, Renewable Northwest)	High	High	WECC wide CO_2 price (federal tax)	Washington CETA, plus all regional RPS regulations in the WECC	PSE recognizes the benefit of a High plus WECC wide CO_2 price as a tax. PSE will make every attempt to include this scenario in the 2021 IRP. However, given the similarity to Scenario 6, PSE will only be able to include this scenario if resources and schedule allow.
8	Mid + Very Gas Price (Joni Bosh, NWEC)	Mid	Very High (25% greater than Mid)	CO_2 Regulation: Social cost of carbon included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC	PSE recognizes the value in identifying the impact of higher than expected gas prices on the power price forecast. However, given the similarity to Scenario 9, this scenario will not be modeled.

	Scenario Name & Requestor	Demand	Gas Price	CO_2 Price/Regulation	RPS/Clean Energy Regulation	Comments
9	Low Demand + Very High Gas Price (Joni Bosh, NWEC and Vlad Gutman-Britten, Climate Solutions)	Low	Very High (25% greater than Mid)	CO_2 Regulation: Social cost of carbon included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC	2021 IRP scenario to understand the impact of higher gas prices combined with low demand on the power price forecast. This scenario has been selected instead of Scenario 8.
10	Mid + $15 CO2 tax (Vlad Gutman-Britten, Climate Solutions)	Mid	Mid	CO_2 Regulation: Social cost of carbon included in Washington state, plus upstream natural gas GHG emissions WECC wide CO_2 tax of $15/ton + inflation	Washington CETA, plus all regional RPS regulations in the WECC	2021 IRP scenario to evaluate CO_2 tax pricing structure in addition to existing regulation on the power price forecast.
11	Mid + Increased Renewable Energy (Vlad Gutman-Britten, Climate Solutions)	Mid	Mid	CO_2 Regulation: Social cost of carbon included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC 100% OR RPS (similar to CETA), Xcel Energy, Idaho Power, Avista clean energy commitments	2021 IRP scenario included to understand future clean energy regulation and utility commitments on the power price forecast.
12	Low Growth	Low	Mid	CO_2 Regulation: Social cost of carbon included in Washington state, plus upstream natural gas GHG emissions CO_2 Price: CA AB32	Washington CETA, plus all regional RPS regulations in the WECC	2021 IRP scenario included to understand the potential long-term impact of COVID-19 on the regional economy and slower regional growth impact on the power price forecast.

Summary of all updates

PSE appreciates the feedback provided by stakeholders. In summary, the following changes will be implemented into the power price model:

- Updated gas price forecast to include recent socioeconomic impacts of COVID-19 pandemic
- Inclusion of the 2019 Update to the 7^{th} Power Plan regional demand forecast
- Modeling of higher Washington State clean energy implementation in 2030 (i.e. Scenario 1)
- The renewable need will be recalculated with the 2019 Update of the 7^{th} Power Plan regional demand forecast and a Washington CETA requirement ramp starting point at the existing amount of non-emitting/renewable resources in 2022

When the 2021 IRP power price scenarios are completed, PSE will provide a spreadsheet with a conversion from nominal to real dollars.

PSE is committed to keeping our stakeholders informed of our progress toward incorportating feedback into the IRP process. PSE will review the list of scenarios with stakeholders at the August 11, 2020 webinar and open for the floor for discussion around the details of these scenarios. Then the completed power price forecast scenarios will be presented at the October 20, 2020 webinar.

Webinar #3: Transmission Constraints Q&A

DRAFT 7/1/2020

Overview

On June 30, 2020 Puget Sound Energy hosted an online meeting with stakeholders to discuss transmission constraints. Stakeholders shared their input on transmission capacity constraint modeling methodology, transmission capacity constraint magnitudes, and how to model transmission capacity uncertainty. Additionally, participants were able to ask questions and make comments using a chat box provided by the Zoom platform.

Below is a report of the questions submitted to the chat box. Answers to the questions were provided verbally by IRP staff during the webinar. Please note that questions were answered in order of relevance to the topic currently being discussed. Questions regarding other topics were answered at the end of the webinar session.

To view a recording of the webinar and to hear responses from staff, please visit the project website at pse-irp.participate.online.

Attendees

A total of 61 people attended the meeting, plus another 13 attendees who only called into the meeting and did not identify themselves (74 people total).

Attendees included: James Adcock, Anika Argunta, Larry Becker, Charlie Black, Rob Briggs, Rachel Brombaugh, Colin Crowley, Cody Duncan, Kara Durbin, Lori E, Ben Farrow, John Fazio, Jeff Fox, Kyle Frankiewich, Zach Genta, Brian Grunkemeyer, Ron Hankewich, Fred Heutte, Brandon Houskeeper, Doug Howell, Kevin Jones, Pete Jones, Eric Kang, Brendan Kelly, Mark Klein, Cathy Koch, Corey Kupersmith,, Sarah Laycock, Steve Lewis, Virginia Lohr, Jim Loring, Lisa MacKay, Kassie Markos, Don Marsh, Jennifer Mersing, David Meyer, Justin Moffett, Brian Muoneke, Anne Newcomb, R.C .Olson, Anthony O'Rourke, Bill Pascoe, David Perk, Phillip Popoff, Andrew Rector, Lowell Rogers, Jason Sanders, Matthew Shapiro, Cindy Song, David Tomlinson, Brian Tyson, Katie Ware, Wendy Weiker, Elyette Weinstein, Willard Westre, Bob Williams, Scott Williams, Ned Witting, and Zac Yanez.

Questions Received

Questions from attendees are posted in the order in which they were received. The webinar began at 1:30 PM PDT and ended at 4:06 PM PDT.

Time sent	Name	Comment
13:31:59	Alison Peters	For those just joining, we are waiting just a couple more minutes for folks to arrive. Thank you!
13:34:28	Fred Huette	Will we be able to ask questions and make comments by voice or only in the chat?
13:36:11	Alison Peters	Hi Fred, I can answer that now and let's make sure everyone sees the response. Attendees can ask questions in chat or verbally. Thank you!
13:37:12	James Adcock	Jim Adcock is here.
13:37:29	Doug Howell	Doug Howell is here.
13:37:35	Don Marsh	Don Marsh
13:38:29	James Adcock	Where's the mute button?
13:38:33	Kyle Frankiewich	Hello everyone, Kyle Frankiewich with WUTC staff here.
13:38:43	Kevin Jones	Jim, Doug and Don - please check your email for a recent communication from me
13:39:06	Charlie	Charlie Black is present
13:39:18	Virginia Lohr	Was there a way for us to know PSE's level of public engagement intended for this meeting beforethe meeting?
13:39:18	Fred Heutte	We're not seeing the mute button in Zoom on our end, so presume the audio has been disabled for participants.
13:39:39	Don Marsh	I assume "unmute" will become available later in the presentation?
13:40:39	Don Marsh	I know how to use "unmute" on Zoom, but there is no option on this webinar. Check your settings presenters?
13:41:04	Don Marsh	Unmute is available now. Thanks.
13:41:06	David Perk	Aha, received the unmute option, thank you
13:41:11	R.C. Olson	Court Olson is present.
13:41:59	Fred Heutte	ok working now thanks
13:41:59	Kevin Jones	Virginia - please check your email for a recent communication from me.
13:42:35	James Adcock	Thank you -- a mute/unmute options just appeared in my Zoom.
13:46:24	R.C. Olson	Kevin, please copy me too.
13:52:23	Kevin Jones	Court - done.
13:52:37	James Adcock	Do all participants know what a "Wheel" is?
13:55:25	David Perk	Thanks, Jim, appreciate that clarification.

Time sent	Name	Comment
13:56:28	James Adcock	Can you explain why you have a "two area system zonal model" but then multiple area "Resource Groups?"
13:57:37	Kyle Frankiewich	Do PSE's generation portfolio optimization tools include some representation of the cost of additional transmission if, for example, some new or augmented T is needed for a given proxy resource?
14:02:09	Kevin Jones	Thanks for explaining the generation / transmission analysis approach. How is storage then added into this analysis approach?
14:05:00	Andrew Rector	I still don't think I get what "PSE's system" is. Is it just PSE's BA or...?
14:06:45	R.C. Olson	Do your lowest costs in the optimization include the social cost of carbon?
14:07:14	Don Marsh	Is Aurora the best modeling software for handling generation, transmission, and storage optimization? Are other utilities using something different?
14:11:00	Kyle Frankiewich	Is WA or OR solar also included?
14:11:28	Zach Genta	Is PSE considering solar from any other regions with higher solar resource values (i.e. Oregon, Idaho, etc.)?
14:11:45	Kyle Frankiewich	I trust that slide 20 was a broad representation of the distance of some of the higher-capacity-factor renewable resources, rather than the exhaustive list of what is being considered.
14:12:15	R.C. Olson	Last year there was talk of considering solar in Idaho, so why does this not appear on your renewable resource options map? (The advantage is they come on line earlielr, because they are farther east.)
14:13:30	Charlie	The map shown on slide 20 only displays solar in wester and eastern Washington. Will this preclude consideration of co-located renewables (e.g., wind and solar) outside Washington?
14:14:24	Fred Heutte	Also asked these in the comment form. At the appropriate time here are two initial questions: (1) what transmission planning models does PSE use (powerflow and production cost) and how will the analysis with those models interact with the AURORA IRP analysis (2) is PSE using the most recent ATC values published by BPA for its transmission paths, especially those with substantial effect on PSE's system, such as West of Cascades North, North of Hanford, Raver-Paul, BC Intertie and the paths from Montana westward
14:14:44	James Adcock	What capacity, if any, does PSE have on the IP line?
14:16:55	Kevin Jones	What plans does PSE have to repurpose the transmission lines from Colstrip MT?
14:17:01	Don Marsh	Are the Tier amounts the maximum available at all times of day, or is there additional capacity at low demand hours?
14:23:05	R.C. Olson	The map on slide 21 shows a transmission connection going toward southern Idaho and Wyoming. Could this line not carry solar power from Southern Idaho
14:25:23	Doug Howell	Many new proposals include combinations of wind and/or solar and/or battery. Does the transmission study account for possible combinations of renewables and/or batteries in one Resource Group Area?

Time sent	Name	Comment
14:26:17	Fred Heutte	my third question: what approach does PSE employ to consider non-wires alternatives to transmission expansion (i.e., new lines) to expand the capability of the existing grid -- thinking broadly this could include in-system elements (phase shifters, static var compensators, storage as a transmission asset, etc.) and also flexible demand/demand response and storage
14:29:42	Ron Hankewich	can you explain how BPA transmission capacity from Lower Snake River area can be delivered across the Cascades? Is there adequate capacity?
14:31:35	Charlie	What is PSE assuming about ability to repurpose transmission from Centralia due to the coal plant retirement?
14:31:40	Brian Grunkemeyer	How does dual purposing your transmission lines affect resource adequacy? My understanding is many of the peakers you would be redirecting from (Goldendale & Mint Farm) are only used for a few peak hours. Sharing with renewable generation could limit your max capacity, correct?
14:36:26	Kyle Frankiewich	Brian, that's a good question, but I was thinking the opposite impact would be the case. If PSE is holding transmission rights for peakers all the time, but only use them infrequently, building renewable resources to piggyback off of those rights could better-utilize them, and the gas peakers could firm up the renewables.
14:36:57	Corey Kupersmith	Has PSE submitted any recent LTF transmission requests into BPA's annual cluster study to gauge the availability of Cross Cascades ATC that is discussed in the Eastern and Southern WA tiers?
14:37:35	Anne Newcomb	Will PSE and partner sources be creating new wind and solar as well as using already excisting? I will stay on mute
14:38:28	Andrew Rector	Are there any upgrades/alterations to the transmission lines in order to achieve dual purposing?
14:39:35	Kyle Frankiewich	Ah, ya, that makes sense, Brian. I don't think it would 'hurt' resource adequacy, but it also wouldn't help. This dual-purpose approach wouldn't increase total capacity available, but would increase the percentage of renewables used to meet load.
14:45:23	Anne Newcomb	Will PSE and partner sources be creating new wind and solar as well as using already excisting? I will stay on mute Thanks,
14:49:49	Anne Newcomb	Will PSE be selling Coalstrip power to other power companies? Muted Anne :-)
14:57:46	Doug Howell	Zoom enables participants to communicate with other individual participants. Would you please enable that function?
14:58:59	Fred Heutte	I definitely have questions about PSE's interest in B2H and Gateway West
15:01:58	Corey Kupersmith	How did PSE consider BPA constraints from Boardman to PSE System for the 400 & 600MW of ID/WY capacity on B2H?
15:02:01	Ron Hankewich	How will you model BESS systems especially if coupled with renewable generation - incremental capacity requirement for discharge or generation time shift?

Time sent	Name	Comment
15:02:21	Alison Peters	Hi Doug, I'm seeing if I can enable this during the meeting. It may have been that it can only be turned off before the meeting starts.
15:04:44	David Perk	+ 1 Fred's comment on new opportunities
15:06:05	Alison Peters	Sharing with all; from Anne Newcomb--Will PSE be selling Coalstrip power to other power companies? (already asked verbally and answered)
15:06:48	Ron Hankewich	I was thinking for BESS more wrt transmission capacity.
15:12:23	James Adcock	Jim Adcock continues to raise his hand for a clarification question.
15:12:54	Don Marsh	Don Marsh has hand raised
15:18:04	David Perk	Agree with Don, an east side battery scenario would be great to see
15:20:57	David Perk	Not an expert, but it would seem that Opt 2 (slide 32) provides a good baseline that could be revised in subsequent IRPs.
15:21:44	Don Marsh	Reducing TX capacity sounds like a good deal for ratepayers if it is backed up by BESS on our side of the Cascades.
15:21:56	Fred Heutte	What thoughts does PSE have about BPA's ongoing changes to its transmission products, especially more flexible variations of Conditional Firm?
15:22:50	James Adcock	Comment: Modern Wind Farm options include choices of hub height for availability, blade design optimized for lower average wind speeds, and inverter options about how high "nameplate" the Wind Turbines can generate before limited by the inverter option chosen. So it's not just a "Transmission Model" issue.
15:22:59	Don Marsh	We would love to see PSE support more rooftop solar panels and batteries. Great for CETA compliance.
15:24:21	James Adcock	Feedback: I would be happy with just "Opt 1" -- which corresponds to the CETA breakpoints of 2030 and 2045.
15:39:49	Jeff Fox	No question, but thank you for mentioning your assumption for MT wind integration cost & that BPA is a potential option for integration. Oh & thanks for MT transmission loss update.
15:40:27	James Adcock	Clarification question re costs on Slide 46?
15:40:46	R.C. Olson	Again, I encourage PSE to consider solar PV in Southern Idaho (along with wind), since it has significant potential to help in the morning peak hours.
15:40:48	Ron Hankewich	Could you translate for us the cost of WY/ID wind to $-kW month so that we have an comparative estimate to the other options?
15:44:57	R.C. Olson	Also add the Idaho solar to the chart on slide 23.
15:47:30	Ron Hankewich	might be easier for me to ask directly? sure I would like to follow up
15:50:34	Fred Heutte	I have a comment on future resource costs.
15:53:37	Brian Grunkemeyer	Why are the battery interconnection costs so high? They're 3x the cost of adding in a peaker plant + its gas pipeline.
15:55:06	R.C. Olson	Are the social costs of carbon included in the CCCT and Peaker costs?

Time sent	Name	Comment
15:55:11	Matthew Shapiro	Is it realistic to include gas turbines in the IRP when the requirement for carbon-free by 2045, since that would mean limiting their use to about 20 years? Or would that shorter lifespan be factored into their economic analysis in the IRP?
15:56:34	Virginia Lohr	I have questiond about the process from May 28 and June 10
15:57:01	Kyle Frankiewich	Are integration costs billed as $/kw-yr or as $/MWh? If it's $/MWh, is there a reason to convert that to $/kw-yr in the optimization model?
15:57:19	R.C. Olson	The social cost of carbon needs to be figured in your cost modeling!!!!
15:58:31	James Adcock	Did you miss Brian's question?
15:58:43	Anne Newcomb	Considering we are moving to 80% renewable by 2030, is it a waste of $ to invest in pipelines and NG infrastructure from now on?
16:01:58	Irena Netik	https://pse-irp.participate.online/get-involved/planning-assumptions-resource-alternatives
16:04:13	Ron Hankewich	Thanks PSE team. you did a great job today. Very informative.
16:05:14	Don Marsh	Appreciate the opportunity to speak in real time. Better than before.
16:05:39	James Adcock	Not happy that our questions do not get answered!
16:06:19	James Adcock	Interconnect costs on 2 hour battery are 43% of capital cost -- Not Reasonable!

The following stakeholder input was gathered through the online Feedback Form, from June 23 through July 7, 2020. PSE's response to the feedback can be found in the far right column. To understand how PSE incorporated this feedback into the 2021 IRP, read the Consultation Update, which will be released on July 21, 2020.

2021 IRP Electric Price Forecast Workshop Feedback Report			
Feedback Form Date	**Stakeholder**	**Comment**	**PSE Response**
6/24/2020	James Adcock (1)	Re Page 50 Please compare battery costs to: Cole, Wesley, and A. Will Frazier. 2019. Cost Projections for Utility-Scale Battery Storage. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-73222. https://www.nrel.gov/docs/fy19osti/73222.pdf. Please make sure that your battery costs are consistent with latest publications, including this recent NREL publication.	Thank you for suggesting an additional data source for inclusion in the 2021 IRP generic resource cost calculation. PSE has reviewed the publication and found that the contents of the report have already been incorporated into our analysis as part of the National Renewable Energy Laboratory's 2019 Annual Technology Baseline (ATB). The Cole and Frazier report was used as the basis for cost projections for the 2019 ATB as discussed on the Battery Storage discussion page of the ATB website (https://atb.nrel.gov/electricity/2019/index.html?t=st).
6/29/20	Kathi Scanlan, WUTC	Question before webinar on transmission constraints: It is important to know the assumptions for the MW capacity of imports on the "interties," B.C. to NW, MT to NW, SW (CA+ AZ effect) to NW. How is company modeling this?	PSE is modeling the following: BC to NW: PSE will not model any capacity on the BC to NW intertie for BC hydro resources. MT to NW: Capacity on the MT to NW intertie is modeled in the Montana resource region. SW (CA + AZ effect) to NW: Capacity on CA/SW to NW intertie is assumed to be unavailable due to constraints on the BPA transmission system.
6/30/20	Virginia Lohr, Vashon Climate Action Group	The Consultation Report from the May 28 IRP meeting has links to find relevant information, but they do not take you to the needed information, only to the overall IRP entire website, leaving the person seeking that information to spend time searching through your website to try to find the information. Here is an example from the Consultation Report: "The capital cost has been updated in the revised summary workbook Excel file for the generic resources assumptions available on PSE's IRP website under materials for Webinar 1 on pse.com/irp." If you follow the link, you will see nothing on that page that says "Webinar 1." I searched a number of pages linked to pse.com/irp, and I could find nothing called "Webinar 1" except in the Consultation Report itself. Please provide meaningful links with accurate titles to the referenced material.	Thank you for your suggestion concerning improving the process with meaningful links with accurate titles to the referenced material. PSE is adopting your suggestions and will continue to improve this aspect of the process to promote meaningful stakeholder participation.
6/30/20	Fred Huette, NW Energy Coalition (1)	Initial questions: (1) what transmission planning models does PSE use (powerflow and production cost) and how will the analysis with those models interact with the AURORA IRP analysis (2) is PSE using the most recent ATC values published by BPA for its transmission paths, especially those with substantial effect on PSE's system, such as West of Cascades North, North of Hanford, Raver-Paul, BC Intertie and the paths from Montana westward	For the purpose of long-term resource planning, PSE does not use transmission planning models to provide the values that are inputted into AURORA. PSE is using the most recent available transfer capacity (ATC) values published by BPA. PSE uses the latest ATC values from BPA for any study or analysis.
6/30/20	James Adcock (2)	While I was generally much happier with the format of today's meeting, I was disappointed that PSE chose to "cut and run" at the end of the meeting rather than allowing the last questions to get asked and answered. In particular, I do not find that your modeling choices of interconnect costs on batteries are AT ALL reasonable! For example you are modeling interconnect costs on 2 hour batteries -- slide 50 -- as being 43% of capital costs!!! This is NOT at all reasonable "modeling" -- in that a utility would never build a project in that manner. In turn, the reason that you are creating such high interconnect costs for batteries is that you are needlessly assuming that battery system sizes are very small compared to other projects such as NG Peakers -- thereby artificially raising the percentage of interconnect costs associated with batteries. In practice, for example, if a utility chose to	Thank you for your feedback. PSE has consistently applied the interconnection cost described in the 2019 HDR Report (linked below) for all generic resources. For all battery types, the assessment assumes a 115 kV, 5-mile tie line to the point of interconnection and a breaker and one half interconnection arrangement at the point of interconnection. These are fixed capital costs, regardless of resource nameplate capacity. The capital cost adder in dollars per kilowatt may appear inflated for

		implement 2 hour batteries, they would choose a much larger battery system size, in order to reduce the percentage of "overhead" associated with transmission connection costs. Can you please review and rework this modeling to more fairly represent interconnect costs on batteries, because frankly right now it looks like you are just trying to "cook the books" to unfairly make batteries appear to be uncompetitive compared to NG Peakers! And frankly batteries have greater siting flexibility that NG Peakers due to lower noise and air pollution profiles, so battery interconnect costs should be much smaller than NG Peakers costs! Recalculate battery storage system interconnect costs to be LOWER than NG Peaker costs on a per megawatt nameplate basis due to the much better siting flexibility that battery storage systems allow.	smaller nameplate resources such as battery resources (25 MW nameplate) and biomass facilities (15 MW nameplate). Given the expectation for significant quantities of battery energy storage systems in the 2021 IRP, PSE will include a 100 MW nameplate battery. The interconnection for a 100 MW nameplate battery would be $91.80/kW in real 2016 US dollars. 2019 HDR Report: https://www.pse.com/-/media/PDFs/001-Energy-Supply/001-Resource-Planning/10111615-0ZR-P0001_PSE_IRP.pdf
7/1/20	James Adcock (3)	In Regards to Transmission Constraints Presentation Page 50 I believe your "Interconnection Costs" for battery storage systems are about 16X too high. For the battery plants the assumption of a 5 mile stub line is unreasonable, since the plant have little siting constraints they can be sited near major transmission lines. Looking for generic costs of interconnect -- since the interconnect requirements for 100 MW of battery storage are essentially "identical" to the interconnect requirements for 100 MW of CT NG Turbine plants, I looked to the following document (from Brattle) page 22. https://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx PJM Electrical Interconnection for CT NG Turbine plants $8 Million for a 355 MW plant. Or $22,535 per MW. Or $22 per KW Where for similar interconnection requirements for Battery Storage Systems you are quoting $367 per KW -- or about 16X higher interconnect costs! Can you please give me references for how you derived your assumed much-higher interconnection costs of $367 per KW ? Thank You, Jim Adcock	See response to James Adcock (2).
7/1/20	James Adcock (3)	Lower your assumed interconnection costs (Transmission Constraints Presentation Page 50) for utility-scale battery storage from $367 per KW to $22 per KW.	See response to James Adcock (2).
7/1/20	Don Marsh, CENSE (1)	Dear IRP Team, In yesterday's presentation on Transmission Constraints, you showed a cost table that anticipated interconnection costs of $367/kW for batteries of any type or duration. This is far higher than the interconnection costs for gas plants, and one of the participants asked why. The answer from PSE was because of the small size of batteries. If I recall correctly, PSE said that the costs were for a 10 MW battery, which is a capacity approximately 30 times smaller than a gas plant, so the economies of scale work out badly for batteries, especially if you assume five miles of transmission line to connect the battery to the grid. There are many flaws with this reasoning: 1. Why is the battery assumed to be so small? A 10 MW battery might have been "cutting edge" a few years ago, but that would be quite small by today's standards. For example, Southern California Edison recently signed seven contracts to acquire 770 MW of lithium-ion battery storage projects (https://pv-magazine-usa.com/2020/05/02/southern-california-edison-wants-huge-770-mw-battery-storage-procurement-online-fast/). Here are the sizes: a) 88 MW/352 MWh Garland Project b) 72 MW/288 MWh Tranquility Project c) 115 MW/460 MWh Blythe 2	See response to James Adcock (2).

		d) 115 MW/460 MWh Blythe 3 e) 230 MW/920 MWh McCoy Project (connected to 250 MW solar farm) f) 50 MW/200 MWh Sanborn Project g) 100 MW/400 MWh (stand-alone) The average size of these projects is 110 MW/440 MW. Why is PSE assuming a battery less than one-tenth this size? Also, the McCoy project is almost the capacity of a peaker plant, so there appears to be little justification for claiming that a battery would have different interconnection costs compared to a peaker. 2. Five miles of transmission cost for a battery overstates the typical scenario. The beauty of batteries is that they can be located close to the load (or the generation resource), without concern for the emissions that make it hard to site gas plants close to neighborhoods. PSE states that siting problems prevented the company from siting a peaker plant anywhere on the Eastside as an alternative to the transmission upgrade project, Energize Eastside. We agree. A gas plant would have significantly more transmission cost to keep it away from population centers and residents who might experience breathing difficulties as a result of the emissions. To properly account for this, we expect the interconnection costs to be higher for gas plants than batteries. Please make this correction. 3. Batteries are more easily scaled to higher or lower capacities than peaker plants. Although there are some modular designs for peakers, the increments are pretty coarse compared to batteries. This means that some of the capacity of a peaker plant might not be needed in a particular location, while batteries can be more easily customized to the exact need. PSE appears to be penalizing batteries for their ability to scale down to 10 MW, whereas it would be hard to find a peaker plant with that miniscule capacity. It would be prohibitively expensive if there were one that small. To be fair, we must compare apples to apples. Please be explicit in your cost table about the size of the resource and its location. For example, if you compare the cost of a 300 MW battery to a peaker, but you divide that battery into 30 pieces and charge 150 miles of transmission lines, that is not the same scenario as a single peaker plant with only 5 miles of transmission. It may well be that 30 distributed batteries provide more reliability, resiliency, and system benefit than a single peaker plant. The batteries should get credit for that. When I first saw these numbers, I feared that my interpretation of the numbers must be incorrect. However, there is ample evidence that other utilities around the country are finding batteries to be a economical choice compared to gas plants. As just one data point, there is this quote from today's issue of T&D World: "According to research completed in 2019 by the Rocky Mountain Institute, 90% of proposed gas-fired power plant construction through 2025 is more costly than equivalent clean energy portfolios consisting of distributed solar, storage and energy efficiency. Further, the economics to operate fossil fuel powered generation is expected to decline significantly, resulting in a higher risk of stranded assets." (https://www.tdworld.com/smart-utility/data-analytics/article/21133422/why-arent-utilities-combining-energy-efficiency-solar-and-storage) If my reasoning and intuition has led me astray, I hope you will explain your rationale for the high cost of battery interconnection. I would expect you would have made this clear during the presentation rather than showing us opaque numbers without adequate explanation. This whole process feels more like hide-and-seek than a collaborative exchange with both parties being treated with professional respect. If this isn't quickly rectified, stakeholders may have to seek remediation from appropriate agencies. That would be a tragic outcome of our sincere effort to participate in matters that directly affect us, our planet, and future generations. Sincerely, Don Marsh	
7/1/20	Don Marsh, CENSE (2)	To accurately assess resource costs, you must factor in the following benefits of batteries: 1. Easier siting than peakers. (Shorter transmission lines.) 2. Stacked benefits (voltage regulation, storage of cheap, clean renewable electricity, relatively easy scaling, T&D deferral, peak demand service, outage service, and others) 3. No emissions. 4. Very fast response (no long warm-up times with high levels of emissions)	See response to James Adcock (2).

		5. Distributed resource (more reliable and resilient than a large plant with a single point of failure) PSE's current analysis appears to ignore these advantages, and we are not confident they will be accurately assessed later in the IRP proceeding.	
7/2/20	Don Marsh, CENSE (3)	Dear IRP Team, We formally request that PSE include in its 2021 IRP and CETA modeling the option of using grid-scale batteries to meet Eastside energy needs as an alternative to the proposed “Energize Eastside” transmission line upgrade. Specifically, we would like to understand how costs and operations compare if a reasonable amount of storage were to be located near centers of heaviest peak demand in Eastside cities. To our knowledge, this option has not been studied (a 2018 Strategen study assumed batteries were placed many miles away from load centers, making batteries only 20% effective in reducing loads on critical transformers). As I mentioned in the Transmission Constraint webinar, batteries offer many economic, environmental, and reliability benefits compared to an 18-mile transmission line: 1. Batteries will save money for ratepayers. The transmission line upgrade is only needed a few hours per year (if that), while a battery can provide grid benefits around the clock, 365 days per year. For example, batteries can earn money by stabilizing voltages, time shifting cheap renewable energy for use during peak demand, and reducing the cost of atmospheric emissions. The Tesla battery in Australia is generating astonishing financial returns (https://reneweconomy.com.au/tesla-big-battery-at-hornsdale-gets-big-jump-in-revenues-more-to-come-65622/). Admittedly, Australia is an extreme case, but we think it’s obvious that batteries will save more money each year for ratepayers than a transmission line will. 2. Batteries will help PSE meet CETA goals. By releasing clean renewable energy during peak hours, batteries will reduce the need to run gas peaker plants, which will account for a higher percentage of PSE’s emissions as the energy mix shifts to renewables. Batteries also help the environment by preserving thousands of valuable urban trees that are threatened by the transmission line project. These trees not only sequester carbon, but their shade moderates the intensity of urban heat islands, reducing the need for more air conditioning during hot summer days. 3. Batteries enhance reliability. Batteries can be distributed throughout the Eastside. Many can be located in existing substations. Besides reducing the risk of a single point of failure, distributed batteries can provide power during local outages, and this is a significant advantage because many power outages occur due to failures of neighborhood distribution lines. Since PSE has had a poor reliability record in recent years (as reported to the WUTC), distributed batteries could help reverse disappointing reliability trends. A holistic view of our energy grid will show that batteries deliver multiple benefits and should be valued accordingly. PSE’s current analysis does not properly value all of these benefits, and therefore batteries appear to be more expensive than gas peaker plants. Many utilities that are using more objective measures are choosing batteries over peaker plants, and it is time for PSE to do the same. If PSE ignores these realities, there is significant risk that the UTC will not allow full cost recovery of Energize Eastside, causing financial hardship for the company and its investors. Please protect their investment and our communities by doing an accurate assessment of the advantages I’ve described here. Sincerely, Don Marsh	Thank you for sharing your thoughts and suggestions.
7/2/20	Don Marsh, CENSE (4)	Please protect your investors and our communities by doing an accurate assessment of the advantages batteries provide compared to the proposed "Energize Eastside" transmission upgrade. The 2018 Strategen report on batteries, paid for by PSE, contains invalid assumptions and cannot be cited as a realistic analysis of the potential of this technology.	Thank you for your comment and suggestion.
7/4/20	Willard Westre, Union of	Slide 28 - Dual purposed transmission of Renewable resources and existing Gas plants is a creative approach. This helps address intermittency, peak load, and resource adequacy issues with renewables without addition of new transmission resources. Dual purposed transmission should be used wherever practical.	Thank you for your comment and suggestion.

	Concerned Scientists (1)		
7/4/20	Willard Westre, Union of Concerned Scientists (2)	Slide 29 – This slide is very misleading. The proposed sale of Colstrip Unit 4 actually reduces the Colstrip transmission line capacity (for PSE) from 750MW to 565MW equaling a 185MW reduction. This proposed sale is very troubling for a number of reasons. From the ratepayer perspective, in my opinion, the proposed sale raises the appearance of a blatant disregard of public trust. Ratepayers would in effect be paying for 185MW of transmission twice – once for the original Colstrip construction and now to restore that capacity. The value of this 185MW of capacity would be approximately $380 million using transmission cost data for new transmission lines from similar locations on the east side of the Rocky Mountains as noted on slide 46. This certainly does not appear to be prudent. From the CETA perspective, the proposed sale increases the cost of replacing the coal power with renewables. The analysis preceding the Dec 11 webinar established that Montana wind was the lowest cost renewable energy generation source available. The proposed sale reduces the amount of that lowest cost resource by at least 185MW thus increasing the CETA implementation cost. From a performance perspective, MT wind has the highest winter season capacity factor matching PSE's peak seasonal load and the highest ELCC rating (needed to meet resource adequacy requirements) of all renewables. With the serious transmission constraint this is critical. Other resource options with lower capacity factors require much higher nameplate MW's and hence require even more transmission capacity. From an environment perspective – one of the rationales given for this proposed sale is to satisfy environment organizational pressure to close the coal plants. Nearly all environmental groups oppose this sale. We only have one atmosphere and it doesn't matter where the emissions are released, they affect everyone everywhere. The proposed sale allows Unit #4 to continue for many years into the future in direct contradiction to the intention of the CETA requirement that they close in 2025. 1. Terminate the proposed sale of Colstrip #4. 2. Retain the full 750MW transmission capacity. 3. The Colstrip transmission line is one of the most valuable assets PSE owns. Maximize its use.	PSE will not model 185 MW as a sensitivity in the IRP analysis because there is a pending WUTC filing for the sale of Colstrip Unit 4.
7/4/20	Willard Westre, Union of Concerned Scientists (3)	Slide 33 – I agree with changing the long-term firm (LTF) transmission policy for renewables. Renewable generation resources rarely operate at their nameplate rating because of weather dependence as evidenced by lower capacity factors. If existing interpretation of LTF is used, transmission lines would rarely be efficiently loaded to capacity requiring significantly more transmission capacity. I recommend transmission policy be linked to the peak seasonal capacity factor of each resource.	Thank you for your support concerning PSE changing the policy to match renewable transmission with actuals instead of name plate capacity factors. PSE is still considering a sensitivity where firm transmission is obtained for lower than 100% of nameplate.
7/4/20	Willard Westre, Union of Concerned Scientists (4)	Slides 48-52 – I appreciate the cost data, but you repeatedly leave out the most important cost and sometimes largest cost – Fuel. You do not even mention it or explain where it fits in the analysis. Newer participants who try to add up the costs to come to some conclusion are misled. Is this intentional? Just give us 1 more slide on fuel cost along with the other costs so it isn't forgotten. Better yet - report all cost data in $/MW, $/KW, $/KWh, or $ MWh.	Natural gas (fuel) prices were discussed at the June 10, 2020 IRP meeting. Though natural gas prices are variable costs that depend on dispatch, natural gas prices are added as a separate cost from the rest of the variable costs. Variable costs are stated as $/MWh because they are dependent on how much electricity is produced at the plant, whereas fuel costs are stated as $/mmBtu since they are dependent on how much fuel is burned.
7/4/20	James Adcock (4)	At the June 30 Transmission Meeting PSE was quoting very high transmission connection costs for battery storage units -- much higher than other technologies. My estimates were that these connection costs were estimated to be 16X too high. I also suggested that battery storage units tend to be located very close to existing connection points -- not the 5-mile connection distance that PSE was estimating. I went back and used aerial photographs to estimate the connection distances for recent large battery storage projects as follows: Ventura Energy Storage: 0.1 Miles to adjacent solar generation facility AES Alamitos Energy Battery Storage: 0.1 Miles to adjacent substation	See response to James Adcock (2).

		Tesla Moss Landing: 0.08 Miles to adjacent substation Reduce the assumed connection distance for battery storage units to the closest reasonable transmission line or substation from current estimate of 5 miles to down to 0.1 miles.	
7/6/20	Bill Pascoe	General Comment PSE appears to be taking a progressive approach to modelling transmission opportunities and constraints for the IRP. This type of forward-thinking approach is necessary to optimize transmission rights in a new planning and market environment with increasing reliance on clean energy resources. Comments on June 30, 2020 Presentation Slide 23 – Pumped storage hydro (PSH) should be modelled in the Montana resource region. Gordon Butte PSH has a FERC license and could use PSE's existing Montana transmission rights, perhaps in combination with Montana wind to "dual purpose" these rights. Slides 25, 27 and 28 – PSE is to be commended for considering "dual purposing" of transmission rights in this IRP. Slide 29 – PSE should model cases with 750 MW of existing Montana transmission rights to reflect the possibility that the proposed sale of 185 MW of capacity to NorthWestern Energy does not go through. Slide 33 – PSE is to be commended for considering less than 100% long term firm transmission rights in this IRP. Slides 45, 46 and 48 – Idaho/Wyoming transmission costs should include wheels on BPA (and any other intermediate systems) in addition to the costs of the ID/WY new builds.	Thank you for your positive and supportive general comment concerning PSE's approach to modelling transmission opportunities and constraints for the IRP. Slides 23: Thank you for your suggestion, pumped storage hydro will be included in the Montana resource group for the 2021 IRP. Slides 25, 27 and 28: Thank you for your positive and supportive general comment concerning PSE's approach to modelling transmission opportunities and constraints for the IRP. Slide 29: PSE will not model 185 MW as a sensitivity in the IRP analysis because there is a pending WUTC filing for the sale of Colstrip Unit 4. Slide 33: Thank you for your support concerning PSE changing the policy to reduce the amount of long-term firm transmission to less than name plate capacity. Slides 45, 46, and 48: For the Idaho/Wyoming wind, the transmission line will only deliver the power to Boardman, so PSE will need to rely on a BPA wheel to deliver the power to PSE load. The BPA tariff rates will be included on top of the costs for Idaho/Wyoming wind.
7/7/20	Anika Arugunta	With the depletion of natural resources each day, there is great need to protect our environment so I feel that there is a great need to encourage organizations such as PSE . PSE is doing a great job in bringing to light these environmental issues and it's working to not only educate others about these issues but also to solve these issues as well, which is one of the reasons why I love to work with PSE. Even considering it would be a long 900 miles to travel on the transmission lines, is PSE looking into creating wind and or solar in or on Coalstrip? This would not only be close to transmission lines and a good utilization of land but also create jobs for any workers displaced by the coal stacks closing down.	Thank you for your comment and suggestion. Because of the location of the site and ownership arrangement of Colstrip, PSE is not looking at developing the Colstrip land for wind or solar. However, PSE is analyzing other wind opportunities in Montana.
7/7/20	Anne Newcomb	Thank you for your dedication to move PSE into the clean energy future! I'm so happy it's finally happening! Increase solar on the Westside of the cascades through incentivizing home and business owners as well as public places to create new solar reducing transmission load over the pass. Work towards more solar that can be produced, used and stored onsite in addition to being fed back into PSE lines, to help with the reduction of load on transmission lines	Thank you for your comment and suggestion.
7/7/20	Katie Ware, Renewables NW	*See attached PDF for comments (2020-07-07 RNW Feedback re PSE Transmission Constraints.pdf)*	PSE responses by number: 1. PSE will not model 185 MW as a sensitivity in the IRP analysis because there is a pending WUTC filing for the sale of Colstrip Unit 4. 2. Thank you for your comment. PSE will ensure all modeling resources accurately reflect the 4.6% line loss for transmission from the Colstrip substation. 3. Thank you for your comment and suggestion. Given that all renewable resources outside of PSE will require wheeling through BPA, the BPA tariff

			rate is a reasonable assumption given that PSE does not have an available integration cost. 4. Thank you for your comment and suggestion. 5. Thank you for your support concerning PSE changing the policy to reduce the amount of long-term firm transmission to less than name plate capacity. 6. Thank you for your suggestion, PSE is weighing feedback received by all stakeholders and will provide a final determination of our modeling approach in the July 21 Consultation Update. 7. Thank you for your suggestion, pumped storage hydro will be included in the Montana resource group for the 2021 IRP. 8. Thank you for your suggestion. PSE is considering the possible modeling approach to satisfy this request and will provide additional feedback in the July 21 Consultation Update.
7/7/20	Fred Heutte, NW Energy Coalition	July 7, 2020 To: Puget Sound Energy From: Fred Heutte, Senior Policy Associate on behalf of NW Energy Coalition Re: 2021 IRP Webinar #3: Transmission Constraints The NW Energy Coalition (NWEC) appreciates the opportunity to provide the following comments on the Puget Sound Energy (PSE) presentation in 2021 IRP Webinar #3: Transmission Constraints on June 30, 2020. 1. NWEC would like to have a review, perhaps in an informal discussion group with technically minded stakeholders, about the interaction between power planning (IRP) and transmission planning at PSE. On the transmission side, our questions include: what transmission models does PSE use (powerflow and production cost), what types of cases or scenarios are used to assess transmission constraints currently and in the future, and how does the transmission modeling assess new resources, resource retirement and transmission expansion over time. On the power planning side, does PSE apply the outputs of previous transmission studies throughout the IRP process, or is there additional transmission modeling to assess scenarios being considered as the IRP progresses? 2. What assumptions does PSE have about interregional transmission constraints, particularly for connections to BC Hydro and also the Pacific Intertie? 3. To what extent will PSE consider non-transmission alternatives to make more effective use of its existing transmission system and transmission rights? This includes both flexible demand (including demand response and storage of various kinds) and in-grid elements including traditional equipment such as static var compensators and phase shifters, and new approaches such as “storage as a transmission asset.” 4. With the ongoing progress of the proposed CAISO enhanced day ahead market (EDAM) proposal, NWEC recommends PSE incorporate a market flexibility scenario for the IRP specifically to address reducing constraints and better utilization of the transmission system. While the elements of EDAM are still in early review, the WIEB Western Flexibility Study and the forthcoming State-Level Market Study (with participation by the UTC and Washington State Energy Office) provide useful elements for modeling the potential capability of enhanced markets. 5. (slide 23) We join with other stakeholders in suggesting that pumped storage in Montana should definitely be included in the IRP Assessment. The Absaroka Gordon Butte project is a very important possibility for integrating Montana wind. 6. (slide 24) In terms of the timing for tiers representing transmission constraints, we suggest 2026 as an important checkpoint in view of the availability of Colstrip transmission facilities and rights, the potential availability of pumped storage, and possibilities for transmission expansion including the BPA Montana-to-Washington project, Boardman to Hemingway and Gateway West.	PSE responses by number: 1. PSE will follow up with NWEC and coordinate an informal meeting. 2. SW to NW: Capacity on CA/SW to NW intertie is assumed to be unavailable due to constraint on BPA system. BC to NW: PSE will not model any capacity on the BC to NW intertie for BC hydro resources. 3. PSE is considering a balanced approach to meeting CETA compliance. PSE will be discussing distributed energy resources (DERs) in the August 11 webinar. PSE will also be discussing transmission and distribution (T&D) planning during the November 4 webinar. 4. Thank you for the suggestion and the accompanying resources. However, given the CAISO enhanced day ahead market (EDAM) is still in the early stages of development PSE will not be including it as a viable market in the IRP process. 5. Thank you for your suggestion, pumped storage hydro will be included in the Montana resource group for the 2021 IRP. 6. Thank you for your comment and suggestion. 7. Thank you for the comment, dual purposed transmission will be included in the 2021 IRP modeling process. 8. The IRP team will be evaluating the portfolio benefits of these transmission project investments, which will assist PSE in making a future decision. 9. Thank you for your comment and suggestion. 10. Thank you for your comment and suggestion. PSE is happy to have a follow-up discussion on this topic. 11. Thank you for your comment and suggestion. 12. PSE is considering expanding cross-Cascades transmission capacity as an alternative and will have an update for the consultation update 13. Per the NREL website, the Mid Technology Cost Scenario is the characterized as "likely" while the Low Technology Cost Scenario is characterized as at the "limit of surprise". PSE has included only the most-likely cases (or an average of high and low cases, as applicable) from other data sources. For consistency, PSE will maintain this precedent for the NREL ATB. 14. See response to James Adcock (2).

		7. (slide 27) NWEC strongly supports PSE's interest in dual-purpose use of existing transmission and transmission rights for gas power plants by incorporating new renewable sources that will improve transmission utilization and provide more system value at low incremental transmission cost. 8. (slide 30) NWEC requests that PSE provide more context for the interest being expressed in the proposed Boardman to Hemingway and Gateway West projects. Since PSE would be a new entrant with existing project sponsors and co-developers, it is important to have a better understanding of what PSE's expectations are for the net benefits to be gained and the timing and form (equity ownership or long term transmission rights) of any such commitments. 9. (slide 31) NWEC requests that PSE discuss in more detail how it views the initiatives by BPA to develop new and more flexible transmission products, such as the anticipated revisions to Conditional Firm. 10. (slide 32) Concerning Option 1 and Option 2 for incorporating transmission constraints into the IRP modeling, NWEC thinks both options may add some value and is interested in a more detailed conversation with PSE on this point. 11. (slide 33) NWEC sees the concept of acquiring renewables while having less transmission capacity than their nameplate worth exploring, but we believe that a more in-depth discussion with renewable developers, Renewable Northwest and NIPPC will be important to understand the commercial considerations involved. 12. (slide 34) Is PSE considering expansion of its cross-Cascades transmission capacity? 13. (slide 49) Concerning the use of the NREL Annual Technology Baseline, we now understand that PSE is using the ATB for future resource cost projections, and we appreciate PSE's response to our previous recommendation that regard. However, we continue to view a midrange between the ATB Mid and Low cost projections the most likely, given our analysis particularly of solar PV costs and a separate experience curve analysis we have conducted. Since the ATB became available a few years ago, our view is that the Mid scenario has overestimated short term cost reductions and it is more appropriate to view the ATB Mid and Low projections as "middle-high" and "middle-low." The ATB does not have a "high" projection; the "constant" projection is simply a straight line extension of current cost estimates useful for their scenario modeling. Therefore, we believe a mid-range between the ATB medium and low projections is the most appropriate cost trajectory for use in IRP modeling. 14. (slide 50) As noted by other stakeholders, the battery interconnection costs indicated in the chart appear to be far too high. Thank you for considering NWEC's comments. /s/ Fred Heutte Senior Policy Associate NW Energy Coalition	
7/8/20	Steve Lewis, Sapere Consulting	1. It appears that some of the 450 MW on PSE's cross-Cascades transmission system is reserved for priority use by the Schedule 449 customers (see https://www.oasis.oati.com/woa/docs/PSEI/PSEIdocs/Posted_Path_Discussion28.pdf). How much of this transmission has been reserved for Schedule 449 customers historically and how much has been used? 2. If the transmission is not used by the Schedule 449 customers, do the remaining core customers of PSE utilize that transmission path as a cheaper alternative to using the BPA cross-Cascades transmission? 3. As long as PSE keeps the Schedule 449 customers whole with respect to cost and reliability, could PSE connect a new resource on the Kittitas transmission system and move the Schedule 449 customer's service onto PSE's long-term BPA transmission from the MIDC? If not, what specifically prevents this approach of reoptimizing PSE's generation and transmission assets for the benefit of their core customers?	1. Per a settlement with PSE's 449 customers, PSE provides firm transmission service to 449 customers on the cross-Cascades path up to the amount of their load. Most of the time, the 449 customers schedule less than their allotted capacity (due to seasonal loads) and the remaining unscheduled transmission is released to the market as non-firm transmission. 2. The non-firm transmission on this path is available in OASIS for purchase by any PSE transmission customer. PSE Merchant (PSE's energy trading group) will sometimes schedule delivery of Wild Horse energy on this path when there is non-firm transmission available. 3. There is not a regulatory or legal mechanism under the FERC Open Access Transmission regulations to transfer the 449 customer's rights under the settlement agreement with PSE (and WUTC Schedule 449 Retail Wheeling Service) to standard transmission tariff service with BPA.

7/9/20	Kyle Frankiewich, WUTC	This feedback, dated July 8, 2020, states the informal comments, questions, and recommendations of Washington Utilities and Transportation Commission Staff. Timely feedback is offered as technical assistance and is not intended as legal advice. Staff reserves the right to amend these opinions should circumstances change or additional information be brought to our attention. Staff opinions are not binding on the commission. Apologies for this comment being a bit late. I am getting up to speed with this new assignment after a few months out of office, but intend to submit future feedback forms within the requested 7-day window. As a newcomer to the 2021 process, I want to recognize PSE for the massive strides made in the company's transparency and public engagement. The website is useful, easy to navigate and contains all presentation information and materials. All meetings are recorded and freely available. This form is a great idea. The commitment to follow up on participants' questions and comments is a customer-focused investment, one that I would wager will pay dividends at the end of the IRP process. Questions from presentation: • slide 17: Does the AURORA zonal model include more than just two zones? The first bullet is a bit ambiguous; I trust that this means PSE considers new generation transmitted to PSE or Mid-C as effectively meeting load (also considering the limit on Mid-C transmission to PSE). Is this correct? Please provide the transmission modeling topology to clarify. To the extent this topology does not align with • slide 17: PSE's presentation included a mention of the limitations of generation-focused or transmission-focused modeling. PSE could use either a generation model or a transmission model, but not both, and chose the generation model. Does PSE run a Tx-given-Gen optimization? Is there a reason why that paradigm is less useful than the chosen Gen-given-Tx approach? • slides 21 and 22: Staff is trying to track PSE transmission that can deliver from the east side of the Cascades to Westside of the Cascades (to PSE BA or to a Westside transmission facility that can be delivered to the PSE BA). In table form, please provide the POD/POI of the existing transmission resources in each of the tiers discussing in the presentation. This could look something like Figure D-6 in the 2017 IRP (pg D-17), but augmented with endpoints. This could also perhaps pair with the maps on slides 21 and 22. Finally, it would be useful to describe the many varieties of transmission rights held by PSE – what attributes of these rights are and are not flexible. Please include this as part of the table. • slide 22: I'm not disagreeing with the use of these resource group areas, but I don't recall why the resource group areas are needed, and how the company settled on these groups rather than some other arrangement. Is there a reason why this modeling approach is more appropriate than other approaches? • slide 22: I heard during the presentation that the "South WA" resource group may include. some of Oregon. Are southern Oregon or CA resources considered? If so, how are any relevant transmission constraints modeled? • slide 23: Staff understands that some prospective pumped storage resources may be available in Montana. Does PSE intend on modeling those resources as well? • slides 25-30: Again, I don't disagree with this approach, but I want to understand how these tiers were generated. I understood that the potential projects and their assignment into tiers is based on PSE's subject matter expertise, rather than a quantitative analysis. Is this a fair description? If so, it may be worth doing some sensitivities to see how significant these assignments are to the resulting optimized portfolio. • slide 25: To clarify, the 1,500 MW of Mid-C T "reserved for Market Purchases" could be used for either purchases or new resource acquisitions, correct? Was that what was meant in the following bullet discussing "dual purpose" transmission? • slide 29: Does the possible sale of Colstrip to Northwestern include any transmission assets that could otherwise be used by PSE for other resources?	Thank you for your feedback concerning improvements to the 2021 IRP process. PSE's responses concerning the presentation by slide number: Slide 17: PSE portfolio model includes two zones, PSE and Mid-C. There is a transmission link between the PSE zone and the Mid-C equivalent to the available Mid-C transmission for market purchases and sales. Transmission constraints discussed in this meeting is the first step toward incorporating generation and transmission optimization. Currently transmission and generation do no interface in the portfolio model. Slides 21 and 22: PSE will be reaching out to you to clarify the request. Slide 22: PSE acknowledges that there are several possible approaches to model transmission constraints within the Aurora framework. These include 1) creation of additional zonal areas; 2) use of the nodal analysis framework; 3) use of the custom constraint matrix; 4) use of the operating constraints table; and 5) use of the resource group table. Creation of additional zonal areas or use of the nodal model would require extensive revision of PSE's current model topology. As this is the first IRP process which PSE is exploring the use of transmission constraints, extreme revision of the model topology did not seem appropriate at this time. PSE understands the remaining three methods could all be incorporated into the existing model topology. Given the resource group table is a 'standard component' of the Aurora model, PSE expects this method to be the most straightforward to use. However, PSE is also exploring the use of the custom constraint matrix and operating constraints table should there be a need for increased modeling flexibility. Slide 22: PSE is currently not considering resources in Southern Oregon or California due to lack of potential transmission. Slide 23: Thank you for your suggestion, pumped storage hydro will be included in the Montana resource group for the 2021 IRP. Slides 25-30: Tier 1, 2 and 3 will be modeled as sensitivities in the portfolio analysis. Slides 25: Yes, the Mid-C transmission could be used for either market purchases or delivery of new renewable resources. Slides 29: The sale of Colstrip Unit 4 to Northwestern includes up to 185 MW of transmission on the Colstrip Transmission System. Slides 33: BPA regularly posts its path ratings including cross Cascades, however it does not include sufficient information to see how those hours correspond to an hourly production profile.

		• slide 33: Has PSE analyzed the utilization of the east-to-west Cascade transmission capacity to determine, at least approximately, how many hours are constrained (i.e. for which short-term or short-term non-firm transmission capacity is available/not available) and how those hours correspond to the hourly production profile of the potential VERs resources? If that is • slide 34: I trust that other distributed resources, such as flexible demand / DR and behind-the-meter storage, will also be considered. Puget-area solar may have limited impact, but other distributed resources might also sidestep transmission constraints. • slide 35: Is there a price component to the assumption that T capacity will be unconstrained in the future? I understand that this modeling choice will help PSE determine where future T investments will bring the most value, but am confused about whether a $0 price along with unconstrained availability will cause the optimization to "wait" on resources to make use of that assumed availability. • slide 44: Are any of the MT transmission costs something that PSE would have to pay even if the asset is unused? Also, are any of PSE's rights along these lines subject to the potential sale of Colstrip? • slides 45 and 46: The ID/WY transmission options are modeled as a capital cost for Tx build. Are there also other Tx rights that would need to be acquired to get from, for example, PacifiCorp's transmission (which I understand would be co-built and co-owned with PSE under this Tx option), to PSE's BA? Are there any pancaked rates to wheel through BPA, or does this option presume that all needed BPA wheeling rights are already owned? • slide 50: The list of interconnection cost assumptions made me think about some extended interconnection delays in other parts of the WECC. Are there any known interconnection queue issues in the resource group regions that should be considered? If so, how are those interconnection constraints represented in PSE's modeling? 1. Testing the importance of tiers: Perform some sensitivity analysis to gauge whether the "tiering" of possible Tx projects has an outsized impact on the optimized portfolio. For example, if dual-purposing Goldendale's 330 MW of transmission is considered Tier 1 instead of Tier 2, how different is the resulting portfolio? Also, if the renewable resource sharing the transmission is not directly co-located, there may be other Tx costs or risks involved in redirecting transmission rights. 2. Transmission modeling options: I'm not fully tracking on the modeling approaches discussed on slide 32, but it seems that Option 2 'bakes in' limitations on Tier 2 and 3 resources such that they are not available at any cost earlier in time. If this is the case, it seems that Option 1 will enable PSE to identify what transmission constraints are best prioritized to access the most appropriate resources. I would appreciate a deeper explanation of how the results of the Option 1 sensitivities would guide PSE. 3. Tx capacity by % of nameplate: I'm very happy to see this being considered, and am excited to see the results. 4. Staff and other stakeholders submitted feedback prior to this presentation. Were those questions and comments recognized during or after the presentation? If not, please help us set expectations and clarify how the public engagement process works with pre-presentation feedback.	Slides 34: Yes, PSE is exploring DR and other distributed resources. These topics will be covered in greater detail in two upcoming webinars on July 14 and August 11. Slides 35: Wheeling and integration costs will be included similar to previous IRPs. Slides 44: We do not anticipate transmission to go unused because transmission can be redirected for short or long-term transmission usage elsewhere on BPA's system. Only the transmission on the Colstrip Transmission System is included in the Unit 4 sale. Slides 45-46: A transmission wheel will be needed on BPA's system from the Boardman site to PSE's system. Slide 50: PSE is only modeling the transmission constraints listed in the slides. PSE's responses concerning additional questions: 1. Thank you for the recommendation. To clarify, the Tier system is intended to provide sensitivity analysis on various possible transmission outcomes. PSE devised the Tier system as a means of exploring transmission uncertainty. During internal discussions, PSE established there were two possible methods of modeling that uncertainty, Option 1 - discreet sensitivity analyses or Option 2 - tying uncertainty to a specific timeframe, given that more transmission may be acquired as more time and effort is expended. PSE thought both these methods seemed a valid exploration of transmission uncertainty and therefore asked stakeholders to provide their perspective. 2. Thank you for your suggestion, PSE is weighing feedback received by all stakeholders and will provide a final determination of our modeling approach in the July 21 Consultation Update. 3. PSE appreciates that the WUTC supports the presentation of transmission capacity by percentage of nameplate and are looking forward to the results. 4. All feedback forms received before the presentation are included in this feedback report. PSE reviews feedback reports prior to the meeting and where possible, PSE revises the presentation of the material based on the feedback received prior to the meeting, where feasible. Pre-presentation feedback opportunities help inform PSE of stakeholder questions and feedback and provide more time for stakeholders to ask questions and have the questions addressed.

PSE IRP Consultation Update
Webinar 3: Transmission Constraints
June 30, 2020

7/21/2020

The following consultation update is the result of stakeholder suggestions gathered through an online Feedback Form, collected between June 23 through July 7, 2020 and summarized in the July 14 Feedback Report. The report themes have been summarized and along with a response to the suggestions that have been implemented. If a suggestion was not implemented, the reason is provided.

PSE also thanks Fred Huette and Joni Bosh of Northwest Energy Coalition (NWEC for meeting with PSE staff to help further clarify their questions and suggestions in follow-up meetings. A meeting with WUTC staff is scheduled for later in the month.

Battery interconnection cost

PSE received feedback from James Adcock, Don March (CENSE) and Fred Heutte (NWEC) concerning the proposed interconnection cost for batteries. PSE has consistently applied the interconnection cost described in the 2019 HDR Report (linked below) for all generic resources. For all battery types, the assessment assumes a 115 kV, 5-mile tie line to the point of interconnection and a breaker and one half interconnection arrangement at the point of interconnection. These are fixed capital costs, regardless of resource nameplate capacity. The capital cost adder in dollars per kilowatt may appear inflated for smaller nameplate resources such as battery resources (25 MW nameplate) and biomass facilities (15 MW nameplate).

Given the expectation for significant quantities of battery energy storage systems in the 2021 IRP, PSE will include a 100 MW nameplate battery. The interconnection for a 100 MW nameplate battery would be $91.80/kW in real 2016 US dollars.

HDR Report: https://www.pse.com/-/media/PDFs/001-Energy-Supply/001-Resource-Planning/10111615-0ZR-P0001_PSE_IRP.pdf

Dual purposed transmission

PSE received feedback from Willard Westre (Union of Concerned Scientists), Bill Pascoe, Katie Ware (Renewable Northwest) and Kyle Frankiewich (WUTC) supporting the inclusion of dual purposed transmission in the 2021 IRP. PSE will incorporate dual-purposed transmission where possible in the 2021 IRP models, in particular, transmission from the Mid-C hub, Goldendale Generating Station and Mint Farm Generating Station.

Colstrip Unit 4 transmission

PSE received feedback from Willard Westre, Bill Pascoe, Katie Ware (Renewable Northwest) and Kyle Frankiewich (WUTC) concerning the inclusion of 185 MW of transmission associated with Colstrip Unit 4. However, the pending sale of Colstrip Unit 4 includes the sale of 185 MW of transmission on the Colstrip Transmission System soit will not be modeled as part of the 2021 IRP process.

Firm transmission as a fraction of nameplate capacity

PSE received feedback from Willard Westre, Bill Pascoe, Katie Ware (Renewable Northwest), Fred Heutte (NWEC) and Kyle Frankiewich (WUTC) suggesting the inclusion of a sensitivity which models firm transmission as a fraction of full nameplate capacity for renewable resources. PSE will be modeling this as a sensitivity.

Pumped storage hydro in Montana

PSE received feedback from Bill Pascoe, Katie Ware (Renewable Northwest) and Fred Heutte (NWEC) supporting inclusion of pumped storage hydro as a resource in the Montana region. PSE reviewed available literature concerning the siting of pumped storage hydro and concluded that Montana does have significant potential for a pumped storage hydro resource. Therefore PSE will include pumped storage hydro as a resource in the Montana transmission region.

Modeling transmission uncertainty

On slide 35, PSE requested stakeholder feedback on methods to model transmission uncertainty. PSE proposed two possible methods: Option 1, modeling confidence level tiers as discrete sensitivities and Option 2, modeling confidence level tiers as time-dependent factors.

PSE received feedback from Katie Ware (Renewable Northwest), Fred Heutte (NWEC) and Kyle Frankiewich (WUTC) concering this topic. Stakeholders suggested that both methods provide value to the IRP modeling process. PSE has elected to model method Option 1, modeling confidence level tiers as discrete sensitivities.

Regional Transmission Organization (RTO) sensitivity

PSE received feedback from Katie Ware (Renewable Northwest) suggesting inclusion of a sensitivity to model the adoption of a Regional Transmission Organization (RTO) in the Pacific Northwest. PSE is still evaluating how modeling an RTO as a sensitivity could be successfully accomplished. A decision on whether this sensitivity will be included is dependent on PSE's models to accurately evaluate an RTO and will be made later in the IRP process.

Expanded cross-Cascade transmission

PSE received feedback from Fred Heutte (NWEC) inquiring about the possibility of modeling expanded cross-Cascade transmission alternatives. PSE is considering modeling expanding our cross-Cascade transmission as an option, but will not have sufficient cost information to model that alternative in the 2021 IRP.

Detailed PSE transmission assumptions

PSE received feedback from Kyle Frankiewich (WUTC) requesting a detailed breakdown to PSE's transmission wheels considered for the 2021 IRP. PSE will be following up with Kyle Frankiewich on July 27, 2020 to further understand his request.

California transmission region

PSE received feedback from Kathi Scanlan (WUTC), Kyle Frankiewich (WUTC) and Fred Heutte (NWEC) concerning transmission capacity and potential modeling of California-based resources. During the Energy Delivery team's review of plausible available transmission, it was found that transmission out of California is significantly constrained. Therefore, no California-based resources will be modeling for the 2021 IRP. However, PSE's existing activity in the Califorina ISO Energy Imbalance Market (EIM) will continue to be modeled.

Transmission from Boardman to Hemingway Project to PSE

PSE received feedback from Bill Pascoe, Katie Ware (Renewable Northwest) and Kyle Frankiewich (WUTC) concerning delivery of power from the Boardman to Hemingway (B2H) projectto PSE's system. This feedback concerns the possible acquisition of transmission on the B2H and Gateway West transmission projects to access Wyoming and Idaho-based resources. Stakeholders noted that an additional BPA transmission wheel is necessary to bring the power home to PSE territory from the northern terminus of the B2H project.

PSE will include Bonneville Power Authority (BPA) provided transmission from B2H to PSE using standard BPA rates. These rates are: $22.20/kW-year for firm transmission plus $11.16/kW-year for wind integration or $8.20/kW-year for solar integration. These costs are in addition to capital costs discussed during the webinar.

Summary of all updates

PSE appreciates the feedback provided by stakeholders. In summary, the following changes will be implemented into the portfolio model:

- Include a sensitivity to model firm transmission as a fraction of nameplate.
- Add pumped storage hydro to the Montana resource region.
- PSE has elected to model method Option 1, modeling confidence level tiers as discrete sensitivities.
- PSE is still evaluating how modeling an RTO as a sensitivity could be successfully accomplished. A decision on whether this sensitivity will be included is dependent on PSE's models to accurately evaluate an RTO and will be made later in the process.
- PSE does not have sufficient cost information to model the cross Cascade transmission in the 2021 IRP.
- PSE will include Bonneville Power Authority (BPA) provided transmission from Hemmingway to PSE using standard BPA rates.

PSE is committed to keeping our stakeholders informed of our progress toward incorportating feedback into the IRP process. PSE will review the list of proposed portfolio sensitivities with stakeholders at the August 11, 2020 webinar and will seek feedback around the details of these sensitivities and additional sensitivities.

PSE PUGET SOUND ENERGY

Webinar #4: Demand Side Resources Q&A

7/15/2020

Overview

On July 14, 2020 Puget Sound Energy hosted an online meeting with stakeholders to discuss demand side resources. Stakeholders shared their input on conservation potential assessment and sensitivities with demand side resources. Additionally, participants were able to ask questions and make comments using a chat box provided by the Go2Meeting platform.

Below is a report of the questions submitted to the chat box. Answers to the questions were provided verbally by IRP staff during the webinar. Please note that questions were answered in order of relevance to the topic currently being discussed. Questions regarding other topics were answered at the end of the webinar session.

To view a recording of the webinar and to hear responses from staff, please visit the project website at pse-irp.participate.online.

Attendees

A total of 57 stakeholders and PSE staff attended the webinar, plus another 12 attendees who called into the meeting and did not identify themselves (69 people total).

Attendees included: Anika Arugunta, Aron Jarr, Anne Newcomb, Brian Grunkemeyer, Cody Duncan, Corey Corbett, Dan Kirschner, David Meyer, David Tomlinson, Don Marsh, Doug Howell, Eddie Webster, Eli Morris, Elyette Weinstein, Fred Heutte, Jeff Tripp, Jennifer Mersing, Jennifer Snyder, James Adcock, Jane Lindley, John Ollis, Joni Bosh, Justin Moffett, Kassie Markos, Kate Maracas, Kathi Scanlan, Katie Ware, Kevin Jones, Kyle Frankiewich, Larry Becker, Lori Hermanson, Lorin Molander, Mark Sellers-Vaughn, Michael Laurie, Michael Noreika, Michelle Wildie, Mike Hopkins, Nathan Gagnon, Philip Puzon, Rachel Brombaugh, R. C. Olson, Rahul Venkatesh, Robert Briggs, Sarah Laycock, Stephanie Chase, Stephanie Price, Ted Drennan, Therese Miranda-Blackney, Thomas Anderson, Virginia Lohr, Warren Halverson, Willard (Bill) Westre, and Zacarias Yanez.

Questions Received

Questions from attendees are posted in the order in which they were received. The webinar began at 1:30 PM PDT and ended at 4:59 PM PDT.

Name	Time Sent	Comment
Alison Peters	**1:22 PM**	Welcome everyone. We will be starting the webinar at 1:30pm.
Alison Peters	**1:26 PM**	Just a friendly reminder as folks are joining to mute yourself.
Alison Peters	**1:37 PM**	You are encouraged to type in your name to the chat box so that folks know who is here. Share with "Everyone." Thank you.
Michael Laurie	**1:37 PM**	Michael Laurie
Brian Grunkemeyer	**1:38 PM**	Question queued up for slide 36: I don't see anything about Demand Flexibility approaches. Specifically, there's no EV load management measure, and it's unclear whether the Heat Pump Water Heater measure is taking advantage of all the great work the BPA has been doing on aggregating water heaters as Demand Flexibility devices.
Doug Howell	**1:39 PM:**	Would please speak a little louder?
Joni Bosh	**1:39 PM:**	Any way to make Gurvinder's voice clearer? He is hard to hear
Kyle Frankiewich	**1:39 PM**	Kyle Frankiewich, UTC staff
Brian Grunkemeyer	**1:40 PM**	Perhaps the answer to my question is slide 43, but Demand Response leaves something on the table vs. Demand Flexibility. We should be modelling resources that can be called every day, not 6 times per year.
Kyle Frankiewich	**1:41 PM**	slide 10: How does the zip code level overlay with PSE's distribution-level planning and with PSE's efforts regarding CETA's equity requirements?
Jane Lindley	**1:42 PM**	What level of International Association for Public Participation (IAP2) engagement will be used in the meeting today? Inform, Consult, Involve or a combination? Thanks!
Irena Netik	**1:44 PM**	This topic is a combination of inform and consult.
Virginia Lohr	**1:44 PM**	Can the slide be shown as a slide, not within PPT, so it is bigger?
Joni Bosh	**1:45 PM**	What other kind of benefits does Plexos provide, specifically?
Kate Maracas	**1:46 PM**	To Gurvinder - does your Plexos flexibility model distinguish between dispatchable DR and those resources that are responsive in real-time? I'm thinking of resources like EV charging vs. real time pricing products.
Doug Howell	**1:47 PM**	How will EE estimates be adjusted once social cost of carbon is accounted for?
Don Marsh	**1:47 PM**	Is local energy storage included in both the Resource Adequacy Model and the Plexos Flexibility Model? It seems that energy storage would provide benefits that would be valuable in both models.
Joni Bosh	**1:50 PM**	Slide 13 What deferral amount did PSE use in the prior IRP? The Power Council value?
Fred Heutte	**1:53 PM**	comment on slide 13: we have provided input to the NW Council that their new value for T&D deferral (lower now than PSE's) needs further review

Don Marsh	**1:54 PM**	What is the effect of the changed T&D number? Does it make transmission more or less costly compares to NWAs? I'm confused because I missed part of Gurvinder's commets because the audio was too distorted.
Kyle Frankiewich (	**1:54 PM**	slide 13 will we see the inputs and calculations for PSE's updated estimates?
Doug Howell	**1:54 PM**	SLide 14. Is there a complete description of the wiggle room that PSE to depart from the NPCC model?
James Adcock	**1:55 PM**	Slide 13 -- I don't understand the large T&D difference between the Power Council 2021 plan vs. 7th plan?
Don Marsh	**1:56 PM**	Can we see the conservation forecast values by zip code?
Don Marsh	**1:57 PM**	Can we also see how the conservation forecast per zip code has changed during recent years?
Brian Grunkemeyer	**1:58 PM**	To extend on Don's questions, have you thought about producing a Locational Marginal Value of Conservation? Kinda like LMP, but annual for directing upgrades to individual substations.
Doug Howell	**2:00 PM**	Louder pleas
Doug Howell	**2:00 PM**	GUrvinder, you are disappearing again
Don Marsh	**2:00 PM**	Can't easily understand Gurvinder, unfortunately.
kevin jones	**2:00 PM**	Could you ask if Gurvinder is using a headset, and if he can try calling on a direct line? The audio is often muffled.
Joni Bosh	**2:02 PM**	Sorry, I cannot hear Gurvinder's answers
R. C. Olson	**2:02 PM**	Gurvinder is sounding very garbeled again.
R. C. Olson	**2:03 PM**	He is still very hard to understand. Elizabeth comes in clear, but Gurvinder fades in and out in clarity.
R. C. Olson	**2:04 PM**	Please share the forumula (equation) used to calculate cost effectiveness.
Joni Bosh	**2:04 PM**	COuld someone please repeat Gurvinder's answers?
Don Marsh	**2:07 PM**	Recommend that Gurvinder try phoning the audio in. The current garbled audio is very taxing on participants.
	2:07 PM	Sorry, I did not get the answer to Kyle's question on slide 13
Doug Howell	**2:07 PM**	I think I got. The methodology is largely the same.
Doug Howell	**2:07 PM**	The measures, values and assumps can be slightly diff
R. C. Olson	**2:13 PM**	I did not gete an answer to my question. Please provide the formula that is in the portfolio model.
Don Marsh	**2:13 PM**	Thanks, Gurvinder. Audio is MUCH better!
Joni Bosh	**2:13 PM**	Thanks
Doug Howell	**2:13 PM**	Gurvinder - you are much clearer now. Thank you.
Elyette Weinstein	**2:15 PM**	Doug you asked a question about values used.

Don Marsh	**2:17 PM**	Documentation of PSE's models and assumptions is so important because some of the conclusions PSE comes to seem to be at variance with what is happening with other utilities across the country. For example, Pacificorp is going much more for battery storage than PSE is. Why is that? Is there something different about PSE's service territory? We need to understand.
Kyle Frankiewich	**2:21 PM**	slide 18 - Not sure CPA would be the logical place for it anyhow, but time-of-use or dynamic rate structures can prompt load-shifting that shares a lot of similarities with DR and other flexible load programs. How will PSE explore those options?
Don Marsh	**2:22 PM**	Slide #18: We haven't seen PSE's load forecast yet. What level of growth was Cadmus provided for its analysis?
Joni Bosh	**2:22 PM**	If load forecasts are complete for this analysis, can you provide those? Slide 18
Michael Laurie	**2:22 PM**	Do the load forecasts take into account the likelihood that commercial building occupancy will be significantly less than it was pre-COVID and that overall demand will likely be less was expected 6 months ago.
Don Marsh	**2:24 PM**	Slide #19: Five sources - why not consider energy storage? This seems like a significant omission.
Alison Peters	**2:25 PM**	Joni, to your question about the forecasts. This will be the topic of the webinar on Sept. 1.
Michael Laurie	**2:25 PM**	Do any of the efficiency and renewables estimates take into account that we may likely have a Democrat president and Democrate controlled Congress which will likely lead to significant federal incentives for more efficiency and renewables?
kevin jones	**2:26 PM**	In the 2019 PSE IRP it was mentioned that the utilty had a gas demand response pilot program. UTC Kathi Scanlan asked for details of this program. Could you explain why your analysis did not contain DR for gas?
Michael Laurie	**2:27 PM**	How is PSE estimating the non-PSE programmatic conservation that will occur due to the new energy codes, C--PACER law, CETA, and the commercial building performance standard law?
Doug Howell	**2:27 PM**	Slide 20. Once the IRP defines "achievable economic" are PSE implementers required to achieve all of this?
Willard (Bill) Westre	**2:29 PM**	Raise hand #13
Don Marsh	**2:29 PM**	Deferring the load forecast until September makes it so hard to judge all these analyses that use the load forecast as an input.
kevin jones	**2:30 PM:**	Why were the load forecasts not reviewed in this forum prior to them being used in the CADMUS analysis?
R. C. Olson	**2:32 PM**	How is the growing trend to switch from gas to heat pump heating being included in this analysis?
kevin jones	**2:32 PM**	Could you tell us the duration of the gas DR pilot?
Rachel Brombaugh	**2:34 PM**	CPACER was signed into law
Doug Howell	**2:36 PM**	Follow up on Slide 20. How do implementers set the EE target from the 'economic achievable?"

kevin jones	**2:39 PM**	WIll the CADMUS analysis be re-done if there are signficant issues with the PSE load forecast? Technical advisors have typically raised concerns about PSE load forecast. How are these results valid?
R. C. Olson	**2:40 PM**	We would like to know when we can plan on hearing a new analysis that includes the heating fuel switching trend that is growing. This is a big flaw in the analysis. What future session will this be presented in?
Michael Laurie	**2:41 PM**	Could you show us the calculations and inputs used to estimate the non-PSE programmatic conservation that will occur due to Washington legislation that has passed recently. This is critical because if this is underestimated it could lead to overbuilding supply side resources. It is not helpful to anyone to know that you will include it in the modeling. Please show us the numbers and details even if that means showing us a simplification of how the model will deal with it. Thanks
Doug Howell	**2:41 PM**	Follow up on slide 20: How can we ensure oversight of this EE target setting? Seems like this is where the rubber meets the road.
R. C. Olson	**2:43 PM**	On slide 21 please provide details on how the distiction is being made between technically feasible and achieveable options?
Joni Bosh	**2:44 PM**	Slide 23 - What is the source for saturation rates? How does the applicability factor differ from ramp rate
R. C. Olson	**2:47 PM**	For deep energy efficiency work on a buliding, a unique set of measures should be used. These vary from building to building in my experience. The results are not typically calculatable by summing the individual measures used. How does the Camus analysis take this realilty into account?
kevin jones	**2:48 PM:**	WIll PSE provide the customer and load forecast used in the CADMUS analysis?
Joni Bosh	**2:49 PM**	Slide 23 - What is the source and the values of these input values? What is included in non-energy benefits? Sorry that should be for slide 14. Slide 24
Warren Halverson	**2:49 PM**	I, too, am disappointed that load forecasts are to be discussed so late in the process. Aren't loads and customers a primary driver. My question about Step 2 is how do you weight the degree of significance of each of these factors?
Alison Peters	**2:50 PM**	Michael, for the question you asked, would you kindly submit a Feedback Form so PSE can provide the level of detail you are asking for? Thank you.
Doug Howell	**2:50 PM**	Slide 24. Does the Total Resource Cost test have the effect of leaving lost energy efficiency opportunity behind?
Michael Laurie	**2:51 PM**	Alison, Thank you. Where or how do I obtain a Feedback Form? Do you have a link to it?
Willard (Bill) Westre	**2:51 PM**	Slide 24 - What discount rate is used for LCOE?
James Adcock	**2:51 PM**	Jim Adcock Raise Hand
Kyle Frankiewich	**2:51 PM**	slide 24: Do CBSA and RBSA data allow for zip code / census tract tailoring based on local building footprints? IE if neighborhood has more MF housing, then MF EEMs will have a greater impact. May link to highly impacted communities and NEIs.

Alison Peters	**2:52 PM**	Yes. PSE will answer questions in writing when folks submit a Feedback Form. Here is the link: https://pse-irp.participate.online/feedback-form
R. C. Olson	**2:53 PM**	How does the Cadmus efficiency modeling calculation figure the building envelope air leakage reduction plays in the reduction of energy conservation due to heating load reduction? It will vary from building to building.
Alison Peters	**2:53 PM**	For this webinar, please submit your form by July 21 and the answers will be posted online by July 28.
	2:54 PM	Slide 26. what is included in "discretionary measures" and what portion is this of the total EE budget?
R. C. Olson	**2:54 PM**	In slide 26, How is the potential long-term economic value calculated? What is the formula used?
Doug Howell	**2:54 PM**	Slide 26 - Please explain "lost opportunity measure?"
Michael Laurie	**2:55 PM**	Alison, Got it thanks
Doug Howell	**2:57 PM**	Slide 26 - Why is ramp rate only 10 years?
Warren Halverson	**2:58 PM**	I, too, am disappointed that load forecasts are to be discussed so late in the process. Aren't loads and customer accounts primary drivers? My question about Step 2 is how do you the degree of signficance of each of these factors?
R. C. Olson	**2:59 PM**	For many efficiency enhancements, impact continues well beyond ten years. Can we get this time frame extended through the full IRP period of 20 years?
Joni Bosh	**3:00 PM**	If measures are bundled by levelized costs, how do you plan to reflect/capture peak energy values? By measures? By bundles? Slide 27
Kyle Frankiewich	**3:00 PM**	+1 for Joni's question
Doug Howell	**3:01 PM**	Will we have time to offer sensitivities on Slide 69?
Willard (Bill) Westre	**3:03 PM**	Ramp rates - Have other utiliities used shorter ramp rates?
Michael Laurie	**3:04 PM**	Have you looked at the case study of the major retrofit of the Empire State Building to include the measures they implemented in your analysis of what is technically feasible?
Elyette Weinstein	**3:08 PM**	What percentage of annual contriubtions does PSE contribute to the NW Energy Efficiency Alliance?
	3:12 PM	How is the unique efficiency impact for an aggregation of measures going to be used to adjust the PSE future efficiency forecast? This is important as future CETA deadlines and C-PACER programs ramp up and deep efficiency improvements catch on in the buildings market place. The 2021 IRP must take this into account, so when will we see appropriate revised efficiency forecasting?
Michael Laurie	**3:15 PM**	What is the relaationship between the CPA and IRP effort versus program implementation? Are the program implementers at PSE required to show a good faith effort to carry out what the IRP concludes is cost effective? If so is there a publicly available report where the implementers document that?

kevin jones	**3:18 PM**	Gurvinder - you did not really answer my question - would PSE provide the load data used in the CADMUS analysis? Will this be the same or different than the load forecast provided in September? If different we would like to understand the differences. If the same, why will PSE not provide the data now?
R. C. Olson	**3:20 PM**	We would like our questions addressed in real time as slides are being presented and as we have multiple PSE people available to answer. Please delay the presentation accordingly!
Don Marsh	**3:20 PM**	+1 for Kevin's load forecast question. At least tell use what rate of growth is being assumed. We can delve into the details in September, but there is no reason to hide the ball today, especially on such a crucial assumption.
R. C. Olson	**3:23 PM**	You missed the legislating update for HB2405 which put C-PACER into law. This needs to be included in your analysis. When will your analysis be adjusted accordingly?
Don Marsh	**Slide #30**	How do the 2023 values compare to NWPCC assumptions? How do they compare to assumptions for neighboring utilities, like Seattle City Light? They seem a little low to me.
Joni Bosh	**3:26 PM**	repeating my question from slide 24 here again - If measures are bundled by levelized costs, how do you plan to reflect/capture peak energy values? By measures? By bundles? Slide 27
R. C. Olson	**3:27 PM**	Your commentary thus far indicates that several things were overlooked and not included in estimating the achievable energy efficiency over the next twenty years. When will these projections be revised to include the increasing trend of deep efficiency improvements which we expect over the next twenty years?
James Adcock	**3:27 PM**	Slide 31 -- There is no "2019 IRP" -- because Puget canceled it. Please fix this.
kevin jones	**3:30 PM**	Slide 33: Is the 26% to 8% drop in achieveable Industrial technical potential due to industrial to commercial reclassification?
Don Marsh	**3:33 PM**	Slide 34: I think you're saying that most of the drop in electric potential is because of lower growth in various categories. So the load forecast should be significantly lower than we saw in 2019. But for now, we just have to guess. Like blind men describing an elephant.
Fred Heutte	**3:33 PM**	Actually, the NW Council has shown some interest in enterprise class data center EE and DR, and even if no such facilities locate in PSE territory (which can't be ruled out), facilities in smaller categories can add up to considerable new load
R. C. Olson	**3:34 PM**	Slide 34 seems to only consider new construction. Some of us expect an increasing likelihood of retrofitting existing buildings. It appears that you are missing this likely occurence over the next 20 years which will likely eclipse the savings impacts from more efficient new buildings. When will your forcast be adjusted to accomodate this likely future trend?

R. C. Olson	**3:38 PM**	To follow up on my question on air leakage consideration, please provide the data source for the detailed envelope factors that Camus says that they use. Thanks.
Doug Howell	**3:41 PM**	Slide 26. That does not answer the question about why can't PSE further accelerate the ramp rate from 10 years to six or eight years.
R. C. Olson	**3:44 PM**	The answer to my question on the 10 year life for measures rather than 20 years, the assumption that measures will only have a weighted average of 10 years is incorrect in my experience. This needs to be revised. When can we expect to see this impact period extended from 10 years to 20 years?
Michael Laurie	**3:45 PM**	Slide 36 includes one measure called "Whole Home". Whole home what? What is that?
Kyle Frankiewich	**3:46 PM**	hand raised - slide 36
James Adcock	**3:48 PM**	Raise Hand -- general question.
Michael Laurie	**3:50 PM**	Slide 39 Back to my point about a likely Democratic federal administration, I think it is critical to consider that there will be a lot more new federal standards when and if that happens.
Kyle Frankiewich	**3:58 PM**	slide 42: what's the difference betwen CPP and behavior DR? If behavioral DR is similar to home energy reports, is it effectively just asking / informing customers of the benefit of shifting load?
R. C. Olson	**3:58 PM**	Where are slides 41 & 42? One was missed and one that appeared wasn't numbered.
Kate Maracas	**3:58 PM**	Slides 24-43: To what extent does PSE rely on demand response aggregators to deploy the the DR products? Could broader use of aggregators increase customer adoption?
Don Marsh	**3:59 PM**	Disappointed the Cadmus didn't include time-of-use rates as a Demand Response product. Although Critical Peak Pricing can help alleviate maximum peaks, a daily TOU rate would make customer batteries more economical, with potentially attractive environmental benefits.
Kate Maracas	**3:59 PM**	Sorry - the above reference was meant to be slides 42-43.
Don Marsh	**4:00 PM**	Slide 44, Cadmus again mentions PSE's 2045 load forecast, which we are not allowed to know for months. This is not acceptable.
Fred Heutte	**4:01 PM**	slide 47: I have a comment on the residential water heat DR potential.
Don Marsh	**4:01 PM:**	Slide 45, does "behavioral load response" = time of use rates? Or is this just critical peak pricing?
Kate Maracas	**4:02 PM**	Slides 42-44: do many of these programs rely on AMI (automated metering infrastructure)? If so, is investment in AMI an impediment to broader customer adoption?
kevin jones	**4:02 PM**	Slide 45: Is uncertain customer acceptance a CADMUS or PSE assumption and what is the basis for the assumption?
Doug Howell	**4:03 PM**	Demand Response: Do the DR benefits include: avoided generation and TX upgrades; avoided distribution upgrades; storage function; line loss reduction from energy savings; ancillary services at generation level such as frequency regulation and spinning reserve; and ancillary services for distribution of voltage control?

Don Marsh	**4:03 PM**	Slide 45 - "uncertainties regarding customer acceptance" is PSE's standard explanation. However, many utilities find customers love demand response programs that provide lower monthly bills. PSE is using assumptions that are decades out of date.
R. C. Olson	**4:04 PM**	Not including the potential for demand control on smart appliances misses a DR potential. Can this potental be included in a revision to the DR calculations?
Michael Laurie	**4:05 PM**	Slide 45 - Agree with Don Marsh's point. PSE please explain what thinking and evidence led to reach a different conclusion than other utilities reached.
Don Marsh	**4:07 PM**	Slide #46, Critical Peak Pricing seems pretty wimpy if only 15% of customers are eligible. Time of use rates could apply to nearly 100% of customers. PSE's reluctance to study time of use is based on one bad experience more than two decades ago. Technology has changed, the industry has learned.
kevin jones	**4:07 PM**	What is the basis of the assumption that energy efficiency occurs before Demand Response? What is your estimate of delayed DR employment while waiting for EE upgrades?
R. C. Olson	**4:08 PM**	Where to you get your PV market penetration function for each year?
Don Marsh	**4:12 PM**	Slide 51. Solar prices are decreasing pretty fast. Does your forecast anticipate cheaper and more efficient solar panels? Most customers will find it's financially attractive to install panels. The adoption rate in that scenario could be higher than your forecast shows.
Fred Heutte	**4:15 PM**	Comment: because the Bass diffusion model relies so much on first-cost for solar market penetration, the future cost estimates for rooftop PV are absolutely pivotal to the outcome, and as we previously said, even the NREL 2019 ATB medium estimates are probably too high and a midpoint between medium and low is more credible.
Fred Heutte	**4:16 PM**	Also, the new 2020 ATB data has just been put online and we are looking through it now. The website is: atb.nrel.gov
R. C. Olson	**4:17 PM**	Could you please define what you mean by combined heat and power?
R. C. Olson	**4:18 PM**	Are you projecting a decline in natural gas use due to switching to heat pumps? If not, when will you adjust your calculations to include this trend?
Michael Laurie	**4:20 PM**	Have you considered the possibility of some uses of natural gas will be banned in new construction as has happened in a number of jurisdictions in California?
Kyle Frankiewich	**4:23 PM**	raised hand for slide 66
Doug Howell	**4:24 PM**	Raised hand for slide 69
Fred Heutte	**4:25 PM**	for slide 63: is there an effective difference between volt/var optimization (VVO) and conservation voltage reduction (CVR), if so has PSE looked specifically at CVR
Fred Heutte	**4:27 PM**	a general comment: NWEC requests that the workbooks for the EE and DR assessments be made available and sufficient time (5 business days at a bare minimum) provided for stakeholder feedback on the CPA after they are made available

Doug Howell	**4:30 PM**	Slide 69 - Raised hand for a recommended sensitivity
James Adcock	**4:32 PM**	Slide 69 -- Distributed Solar pV -- with 3rd party ownership and PSE financial support -- especially in low income communities.
Don Marsh	**4:33 PM**	Slide 69: Like the PSE incentive, but why $0.048 / kWh? I'd like to see a sensitivity with a higher incentive. I think that could make a big difference. Also, I'd love to see what paired batteries could do. How about some incentive on that?
Don Marsh	**4:34 PM**	+1 on a sensitivity on shorter ramp rates, like Doug suggested! A 6 or 8-year ramp rate would be very interesting.
Don Marsh	**4:35 PM**	It is extremely likely that solar panel efficiency will increase during the next 20 years, making panels cheaper. I don't think PSE is taking that likelihood into account.
Michael Laurie	**4:39 PM**	Could you do a sensitivity analysis of conservation achievable if conservation can be done without a loss of revenue to PSE. And a sensitivity analysis of conservation potential if conservation spending was recognized as capital spending, thus allowing PSE to make a profit on conservation spending.
Kate Maracas	**4:41 PM**	+1 to Don Marsh. Also, the increased capabilities of grid-forming inverters that will inevitably be deployed after implementation of IEEE 1547 standards will have a significant impact on solar PV's (distributed and utility scale) ability to provide flexibility and ancillary services. How is PSE considering both the cost reductions and advanced technical capabilities?
Warren Halverson	**4:56 PM**	It seems like resource alterntives -DR, Solar, Batteries. Water heaters etc etc - are only considered on a total market or company basis.
Warren Halverson	**4:59 PM**	I would like to see a more niche approach to using a combination of these solutions, particularly in transmission planning. It seems to me that there are many applications of these solutions in combination to meet residential and/or commercial needs .... let's add some creativity and options to our customers. Thank you.

PSE IRP Feedback Report
Webinar 4: Demand Side Resources
July 14, 2020

7/28/2020

The following stakeholder input was gathered through the online Feedback Form, from July 7 through July 21, 2020. PSE's response to the feedback can be found in the far right column. To understand how PSE incorporated this feedback into the 2021 IRP, read the Consultation Update, which will be released on August 4, 2020.

Feedback Form Date	Stakeholder	Comment	PSE Response
7/8/2020	James Adcock	It is very difficult to read the Draft Demand Side Resources document due to the very large use of TLAs -- Three Letter Acronyms -- which are unexplained in the document. There is also the use of unexplained "random" numbers, such as "8760" Don't use Three Letter Acronyms without giving definition to those acronyms in the document that uses them. Don't use unexplained "random" numbers, such as "8760" without explaining them in the document. Perhaps prior to the meeting you can send out to participants a temporary "dictionary of acronyms and magic numbers" that explains what all your TLAs and "random" numbers in this document? -- So that we don't spend all the meeting time just asking and answering questions like "What does 'GSHP' Mean" and "What does the number '8760' mean?" And then in the final document you can include this "dictionary of acronyms and magic numbers" in that final document.	Thank you for the suggestion. Concerning your examples, 8760 is the hours in a (non-leap) year and used in modeling. GSHP stands for ground source heat pumps.
7/14/2020	Doug Howell, Sierra Club	Please run two sensitivities: 1. Slide 26. Run two more sensitivities on the ramp rate from 10-years to 8-years and 6-years. 2. Non-energy benefits for energy efficiency. Run a sensitivity to show what is the value of non-energy benefits from energy efficiency. The recent EPA study shows that these benefits are about 2 cents/KWh.	Thank you for the suggestions concerning sensitivities. Your three suggested sensitivities have been added to the list of sensitivities for further discussions at the August 11 webinar. Your suggestion of bundling less cost-effective measures with more cost-effective ones to achieve deeper penetration into the market is a

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		In addition, PSE needs to provide assurance that the CRAG and the implementation team are maximizing EE potential for each building such that you still have greater benefits than costs so that you are not just swapping out light bulbs but bundling that with other measures and still come out cost effective.	valid argument. The conservation resource advisory group (CRAG) is a separate process than the IRP public participation process. They work directly with PSE's implementation team to approve their program portfolio. Your suggestion would be something the CRAG process would address.
7/14/2020	Brian Grunkemeyer FlexCharging	I'd like to better understand the cost of your Residential EV direct load control conservation measure. If you're installing hardware in the home, I understand that's not cheap. However, $362/kW-yr seems a little high to me. At FlexCharging, we have a software-only vehicle telematics solution where we can provide managed charging based on the driver's schedule first, then fall back on the utility's needs. This should lead to better customer acceptance and higher adoption. We may be able to provide services for around $250/car/year for the service, plus $50/car/year for driver incentives and some program marketing & administration costs. We believe we can get more than 1 kW-yr per vehicle. I'd like to see how this lines up with your numbers. I'm happy to walk through the numbers with someone.	Cadmus can estimate the levelized cost using the values provided by FlexCharging and compare those to the values we used in a side-by-side comparison. PSE and Cadmus will be reaching out to follow-up with you and will report progress in the Consultation Update.
7/14/2020	James Adcock	We really do need PSE to "vet" their audio systems, and all other aspects of their meeting presentation technology, prior to the start of the meeting so that we don't waste the time and effort of 60+ participants. Unfortunately, this continues to be an on-going problem for many years, where PSE "audio" system continue to fail during IRP meetings.	Thank you for your comments.
7/16/2020	Elaine Armstrong, Citizen's Climate Lobby	What is PSE doing, in good faith and at all speed, to reduce their greenhouse gas emissions, reduce reliance on fossil fuels and create a 100% green and reusable energy sources? What you are doing now is increasing reliance on natural gas. There should be no more new plants that use fossil fuels. You need to create ways to use solar, wind, geothermal etc. Entire nations are able to do this. Surely PSE can.	PSE is modeling 80% renewable resources by 2030 and 100% by 2045 to meet the Washington Clean Energy Transformation Act (CETA). PSE is also modeling portfolio sensitivities around different clean energy futures which will be discussed at the August 11, 2020 webinar on scenarios and sensitivities.

Feedback Form Date	Stakeholder	Comment	PSE Response
		Build no new fossil fuel plants. Create clean energy sources with the eye to be entirely greenhouse gas emission-free by 2040. Do more to support homeowners to overcome the giant cost of installing solar on their homes.	
7/19/2020	Willard Westre, Union of Concerned Scientists	Slide 19 – At 2:29pm in the webinar I asked verbally two questions that were not documented in the Q&A report, nor the responses to them. My first question was directed to Lakin Garth with regard to his extensive experience in working with other utilities. I asked him if, in addition to Electric and Gas sources of conservation there was another source, namely, fuel switching between Gas and Electric (e.g. replacing gas furnaces with electric heat pumps). His answer was yes, that this was another viable source. My second question was why wasn't this data included in the presentation. His answer was to refer to PSE staff, implying that the decision was made by PSE. Fuel switching as a conservation resource should not be off-the-table for PSE as this represents a very substantial percentage of the residential and commercial conservation that can be achieved. The use of gas for heating is a major component of PSE's total. Switching to electric heat pumps results in an energy saving of up to 75% and is not costly when timed with end-of-life-replacement. PSE does not effectively offer rebates for this conservation. That was not always the case – in 2010 I received a $1500 rebate for replacing my gas furnace with an electric heat pump. That rebate is not available now. Sometime since 2010, PSE has dropped this major future source of conservation from its plan, significantly reducing its overall conservation effort. Recommendation: PSE develop an aggressive fuel-switching component to its conservation plan, including replacement of gas heating systems with heat pumps. This would help PSE bolster its conservation resources and reduce	PSE responses by paragraph and referenced slide numbers: Fuel conversion from gas to electric is a combination of a gas savings measure and an electric load building measure. This is not a true conservation measure and PSE would not characterize it resulting in 75% energy savings. Fuel conversion is mostly driven by carbon reduction objectives, assuming that the electric supply would be non-emitting. PSE would not generally characterize these measures as low cost since adding electric space heating equipment will likely result in upgrades to the electrical circuits and more expensive heat pump equipment. PSE will be considering a sensitivity where some amount of gas loads are converted to electric. Further discussions will occur at the August 11 webinar on scenarios and sensitivities. The rebate of $1500, that PSE used to offer, was not for converting to electric, but rather for choosing a more efficient electric system, like a high efficiency ductless heat pump, which has a higher cost. The incentive encouraged customers to adopt a more efficient system. In other words,

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		its requirement for new CETA-required generation resources. Additionally, it would reduce PSE's overall carbon emissions which is critical to achieving zero emissions by 2040. Slide 35 – This slide shows a cumulative achievable technical efficiency potential of 142MW for the year 2026. The Dec 11 presentation Slide 21 shows 336Mw for 2026. Can you explain the reduction in potential efficiency?	if you converted to electric but chose an inefficient electric system you would not have qualified for the rebate. Slide 35: The slide from the December 11, 2018 presentation included all demand side resources including codes and standards. Please also note that for 2026 of the previous study, there were 6 years of conservation since the study started in 2020 (2020-2026), and the current study has only four years of conservation since its starts in 2022 (2022-2026).
7/19/2020	Anne Newcomb	Thank you for including me in the PSE IRP! I will be on a backpacking trip :-) for July 21st but I look forward to participating in the rest! Having lived in Puget Power and PSE territory most of my life I greatly appreciate your track record of offering energy efficiency programs to your customers. Considering it is estimated energy efficiency can reduce demand between 5-30% and possibly more, I highly recommend significantly increasing your investments in energy efficiency programs over the next 5-10 years and include these specific offerings: ○ Fully-subsidized and high-quality energy audits including calibrated blower door tests and thermographic inspections. ○ Well-subsidized window replacements. ○ Well-subsidized resilient and long lasting insulation. Spray foam has the highest R-value and may never need replacement which makes for a great investment too! In addition to energy efficiency, smart grid AI and machine learning technology is the way of the future. BPA has investing in and is using Auto Grid (https://www.auto-grid.com/) to help balance demand. I can see PSE is also working to create a smarter grid including the newly installed smart meters. What smart grid technology is PSE using now and what is your	Thank you for your thoughts and suggestions! PSE is taking a holistic approach to grid modernization that includes several smart grid technologies in addition to traditional infrastructure improvements. Examples of our investments in smart technologies include substation SCADA (Supervisory Control and Data Acquisition), distribution automation, and an Advanced Distribution Management System (ADMS). Substation SCADA is a program that enhances PSE's telecommunications infrastructure to remotely monitor and control our substation equipment in real time. PSE is planning for all substations to be equipped with SCADA improvements by 2025. Distribution Automation (DA) – often described as a "self-healing grid" – is technology that provides monitoring and control of our distribution circuits to help us detect outages more quickly and address them faster and more effectively. Advanced Distribution Management System (ADMS) is a computer-based platform that will enable an integrated real-time approach

Feedback Form Date	Stakeholder	Comment	PSE Response
		roadmap/plan for utilizing this technology to help achieve a clean energy future?	to distribution grid management and optimization, and for the integration of more distributed energy resources. The ADMS platform is currently in deployment and is expected to be complete in 2022. These technologies will help achieve a clean energy future.
7/19/2020	Rob Briggs, Vashon Climate Action Group	Comment #1 – Evaluate higher ramp rates for energy efficiency programs I strongly support Doug Howell's suggestion that the IRP evaluate the option of accelerating the ramp rate to 6 and 8 years for efficiency measures rather than 10 years. Doing so will evaluate a policy capable of reliably delivering early emissions reductions that have been consistently shown to be effective employment generators. Doing so would also balance other emissions reduction policies and measures that inherently have longer lead times and entail greater technical risk and/or economic uncertainty.	Response #1: Thank you for this comment. Modeling accelerating ramp rates as additional sensitivities is being considered and will be discussed at the August 11 webinar on scenarios and sensitivities.
		Comment #2 – Evaluate gas to electricity fuel switching programs The IRP needs to include the assessment of measures that entail switching loads from natural gas to electricity. While this may not have been included in previous IRPs, the writing is clearly on the wall that fossil methane use will be greatly curtailed or eliminated for climate reasons in the future. While one can imaging future power plant technology that could capture and sequester carbon, there is no plausible technology that could do that for distributed uses of natural gas. Washington State has committed to decarbonize its economy, and in California some regulations have already been enacted to shift loads from gas to electricity and many more are now being proposed. The IRP process was created to prevent egregious errors from being made in infrastructure spending, like Washington Public Power System. Rate payers continue to pay millions of dollars per year for mistakes made nearly 40 years. It would be utter folly to fail to include this inevitable and enormously consequential process of curtailing use of fossil methane through fuel	Response #2: PSE will be considering a sensitivity where some amount of gas loads are converted to electric. This will be further discussed at the August 11 webinar on scenarios and sensitivities.

Feedback Form Date	Stakeholder	Comment	PSE Response
		switching in a process mandated to plan energy systems 20 years into the future.	
		Comment #3 – Excessive use of acronyms and abbreviations and poor graphic presentation If the purpose of the IRP webinars is to inform stakeholders and field their input, then it would behoove PSE and its contractors to decrease the use of acronyms, particularly those that are not explained. When participants' attention is consumed attempting to parse specialized abbreviations or language, they are not able to attend to the substance of what is being communicated. Slide 44 is a good example of excessive use of unexplained abbreviations and poor graphic design. I note that none of the abbreviations are explained at the bottom of the page, as would be appropriate. Use of these abbreviations in oral presentation, as was done extensively in this last webinar, is doubly problematic because of the near impossibility of both listening and at the same time searching the presentation document to see if the abbreviation was explained. Slide 44 attempts to do too much and as a result doesn't effectively communicate any of the things the audience might reasonably want to know. Any comparison between IRPs doesn't work because the measures don't align. What measures were added or subtracted for 2021? On which measures have assumptions changed? What measures are most impactful? What measures were most cost-effective? Answers to all these questions are hidden by poor presentation.	Response #3: PSE notes that use of acronyms and abbreviations and graphics can be a barrier to understanding and will make efforts to improve meeting materials for all audiences as we are able. Slide 44: The following list defines the abbreviations: ▪ EV: electric vehicle ▪ DLC: direct load control ▪ HPWH: heat pump water heater ▪ C&I: commercial and industrial ▪ DR: demand response ▪ ERWH: electric resistance water heater ▪ CPP: critical peak pricing ▪ BYOT: bring-your-own-thermostat In terms of measures that were added for 2021, slide 45 notes that behavioral demand response, electric vehicle service equipment direct load control, and both grid-enabled and switch technologies were applied to both electric resistance and heat pump water heaters. No measures were removed. The most impactful measures are shown on slide 46.

Feedback Form Date	Stakeholder	Comment	PSE Response
			Slide 44 shows each demand response product's levelized cost from lowest to highest from top-to-bottom. The cost-effective amount of conservation will be determined from the IRP portfolio analysis.
		Comment #4 – Better evaluation of electric vehicle load management Interestingly, the measure on the graph on page 44 that appears to be the least cost-effective and to have only very modest impact—residential electric vehicle direct load control—is one that I would have assumed would be among the most cost effective and most impactful. It appears to have an associated cost of $362/kW-yr. Electric vehicles using level 2 chargers pose large loads—larger than residential water heaters and comparable to central air conditioners and heat pumps. Yet charging vehicles in most cases is not time dependent, hence customers likely need little incentive to shift the time at which they charge. Would you please provide the data sources that were used to establish the very high cost for load management for EV charging. There is enormous up-side potential in using the charging of electric vehicles to improve the efficiency and reduce emissions from the electric power sector and also large down-side risk if those loads occur at the wrong times. This seems like a critical assumption to get right, because public policy is likely to shift radically in the coming years to favor EVs, and it seems critical that PSE have a plan in place to manage them. Would you please provide references for the data sources that were used to establish the very high cost for load management for EV charging.	Response #4. Cadmus will provide the assumptions used for residential electric vehicle charging DLC in the consultation update.
7/20/2020	Virginia Lohr, Vashon	I have reviewed Webinar #3: Transmission Constraints Q&A. It states that all questions were answered. I do not recall hearing an answer to my question:	The level of public participation per IAP2 is available in the IRP schedule filed with the WUTC and posted on pse.com:

Feedback Form Date	Stakeholder	Comment	PSE Response
	Climate Action Group	"Was there a way for us to know PSE's level of public engagement intended for this meeting before the meeting?" I now have 2 questions: 1. Was my question actually answered during the webinar? 2. What is the answer to my question?	https://oohpseirp.blob.core.windows.net/media/Default/PDFs/UE-200304-UG-200305-PSE-Appendix-A-(07-08-2020).pdf PSE has routinely defined the level of public engagement at the beginning of the presentation and will consider adding the level more prominently on the website in the future. 1. PSE acknowledges that the question was asked in the chat and the response was not documented in the chat. 2. The IAP2 level of public participation for the July 14 webinar was Consult.
7/20/2020	Joni Bosh, NWEC	NW Energy Coalition (NWEC) appreciates the opportunity to provide feedback on the presentation on demand side resources of July 14th, 2020. We start with three general points on the presentation. 1. It was unfortunate that there was not enough time to discuss stakeholders' questions for four of the five topics; it may be worth considering having fewer topics per session and adding sessions. 2. Please explain the process and schedule for completing the 2021 IRP Conservation Potential Assessment. How will the CPA be adjusted when the final load forecast for the 2021 IRP is available? 3. NWEC requests that the workbooks related to the July 14 presentation be made available via the 2021 IRP web site. Once posted, we request sufficient time to review the material with a comment form deadline of at least 5 working days, and preferably 10 working days. It is particularly important to have access to the Demand Side Resource workbooks and any related materials. Other information and data used for IRP inputs, such as generation cost estimates, typically rely on national assessments such as the NREL Annual Technology Baseline, or generic assumptions from public data compiled by PSE staff and consultants.	Response #1. Thank you for this suggestion. Response #2: The CPA was started in January and the webinar was the culmination of that work. The company F2020 load forecast was simultaneously under development during this time. The load forecast informs the new construction measures based on the customer growth, and not the retrofit measures. A draft was available in late May and it was used to estimate the new construction opportunities in the CPA. The final load forecast did not change much from the draft: the annual energy loads did not change, and the peaks are a little lower than the draft peaks used in the CPA, by 0.30%. These changes are not material and will not change the results of the CPA. More details of the load forecast will be presented at the September 1, 2020 meeting. Response #2. Response included in above response.

Feedback Form Date	Stakeholder	Comment	PSE Response
		However, demand side resource estimates must be localized and depend on the specific characteristics of PSE's customer base and the historic, current and projected costs and other factors involved in acquiring these resources. For that reason, it is particularly important to review the detailed data underlying the conclusions of the July 14 presentation and eventual inclusion of inputs into the IRP modeling going forward. As a result, the comments here are provisional responses to the material presented on July 14, and we reserve the right to provide further comments after reviewing the supporting material. Our comments and requests are presented by slide below, identified by page number and title.	Response #3. PSE can provide some workbook components that have measure details and assumptions used in the CPA. PSE will reach out to NWEC to discuss this request further.
		Slide 14 - Updates in 2021 CPA: T&D deferral benefit The deferral amount has substantially changed. Please provide the specific assumptions that have altered since the last IRP when the value used was $64.77/kW-yr.	Slide 14: PSE updated the analysis for the 2021 IRP and is currently assessing what information can be made public. Additional information may be provided in the Consultation Update.
		Slide 20 - Types of Energy Efficiency Potential One of the most important reasons for our request to review the workbooks and related materials for the energy efficiency analysis is to be able to trace the process from assessment of technical potential for measures and programs to the achievable technical potential and then the achievable economic potential. Among other things, this will enable comparison to the NW Council's analysis and other utility IRPs in the region.	Slide 20: PSE acknowledges and will be reaching out to you to discuss.
		Slide 27 – Step 6. Develop Supply Curves for IRP Modeling If measures are bundled by levelized cost ranges, please explain how PSE will capture and reflect peak energy values for each measure? An illustrative example might help with that explanation.	Slide 27: The levelized costs currently include the peak demand benefits of deferred T&D. The avoided generation capacity benefits are applied within the portfolio model.
		Slide 30 – Electric Energy Efficiency Potential Please provide the worksheets behind this summary. NWEC also requests an explanation of when and how the assessment of the social cost of greenhouse gases required by CETA is included in this analysis, and how	Slide 30: The SCGHG will be an input in the portfolio model and will be applied to all resources including demand side resources. The effect of SCGHG is to increase the cost of fossil

Feedback Form Date	Stakeholder	Comment	PSE Response
		that will be reflected in changes to achievable economic potential for energy efficiency at later stages of the IRP process.	fuel based resources and thus would favor more conservation. Eventually, the avoided cost that are developed from the post IRP process for use in conservation program planning will include the SCGHG adder.
		Slide 31 – Comparison to 2019 CPA The difference between 2019 and 2021 is a 20% reduction in Total Achievable technical potential. While most of this is explained as changed in commercial forecasts, please explain in detail the assumptions behind the reduced potentials for industrial and residential as well.	Slide 31: Overall residential potential is largely unchanged between the 2019 CPA (306 aMW) and 2021 CPA (314 aMW through 2041). Industrial potential is lower due to re-classification of some commercial customers from the industrial sector in the 2019 study.
		Slides 36, 37, 38 – Top Residential/Commercial/Industrial Electric Measures NWEC is concerned with the context and some of the specific detail in these tables. The second column is "Weighted Average Levelized Cost ($/kWh)" but the time period is not indicated, nor whether these are cumulative costs. It is difficult to interpret the sign and scale of many of the indicated values, for example, $0.40/kWh for residential windows, a negative value (-$0.064) for clothes washers, but a positive value ($0.275) for clothes dryers.	Slide 36, 37, and 38: The measure categories in the tables on slides 36, 37, and 38 are comprised of many individual measure applications. These are aggregated into measure categories to ease reporting. Because every individual measure includes its own levelized cost, we created savings-weighted levelized cost at the measure category level. These costs are levelized over the 24-year electric study horizon. Residential windows are a relatively expensive efficiency measure; clothes washers have a negative levelized cost, primarily because of the relatively high value of the non-energy impact of water savings, whereas clothes dryers do not accrue any NEIs and have a relatively higher incremental cost than clothes washers.
		Slide 42 – Demand Response Projects NWEC requests that PSE include in the IRP some discussion of the additional benefits of aligning programmatic DR with effective time of use rate design. There has been considerable analysis of these interactive effects,	Slide 42: PSE will add a discussion on time of use rate in the draft IRP report.

Feedback Form Date	Stakeholder	Comment	PSE Response
		and current program efforts, for example the Portland General Electric DR Testbed, are assessing the overall gain from a coordinated approach rather than having program and rate design be developed separately.	
		Slide 44 – Comparison to the 2019 CPA We refer to our earlier comments about the importance of reviewing the underlying workbooks for this analysis, in particular for demand response. That proved to be important in the work of the NW Council's Demand Response Advisory Committee in reviewing inputs for the 2021 Northwest Power Plan, based on a template system for DR analysis provided by Cadmus. At this time, we provide initial comment on one DR measure, grid-enabled water heaters, while reserving the right to provide further comment on this and other measures after reviewing the DR workbooks and supporting materials. The grid-enabled water heater measure has rapidly emerged to be a leading DR resource for PSE. The recent adoption of the CTA-2045 interface module requirement for all new electric water heaters in Washington by January 2022 elevates the importance and availability of this measure even higher. The July 14 presentation indicates a total peak reduction potential of over 60 MW. There is no indication of time duration for the supply curve, but we assume that to be through 2041. As a result of the CTA-2045 requirement, NWEC assumes a much higher resource potential and much faster realization. Taking a very simple approach, we assume 600,000 electric water heaters currently for PSE residential customers and a 12-year resource life, with 50,000 replacements per year. Using the NW Council estimate of 0.5 kW average peak reduction per unit (assuming 4.5 kW demand per unit and a coincidence factor of about 12%), that equates to a technical potential of 25 MW per year and a total potential of 300 MW. This is far greater than the 60+ MW indicated on Slide 44. We recognize that achievable economic potential will be affected by customer acceptance and other reasons, but additional factors also should be	Slide 44: This slide shows 71 MW of residential water heat direct load control. The 71 MW are achievable technical potential which includes an assumption that program participation is equal to 25% of the eligible customer population (i.e. residential customers with electric water heating). This program participation value is the same assumption employed by the Council in its draft 2021 Plan demand response supply curves. Dividing the 71 MW by 25% equals about 284 MW of technical potential, a value similar to NWEC's estimate.

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		considered. For example, a recent report for the Northwest Energy Efficiency Alliance (screen shot below) indicates that about 70% of water heaters are replaced for burnout, but another 30% are purchased for other reasons. New residential units should also be accounted for. Because of the magnitude and favorable cost of the grid-enabled water heater resource, it is important to refine the analysis before setting the inputs for the 2021 IRP. Water Heater Market Characterization Report, #E18-305, April 2018, prepared for NEEA by Russell Research:	

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		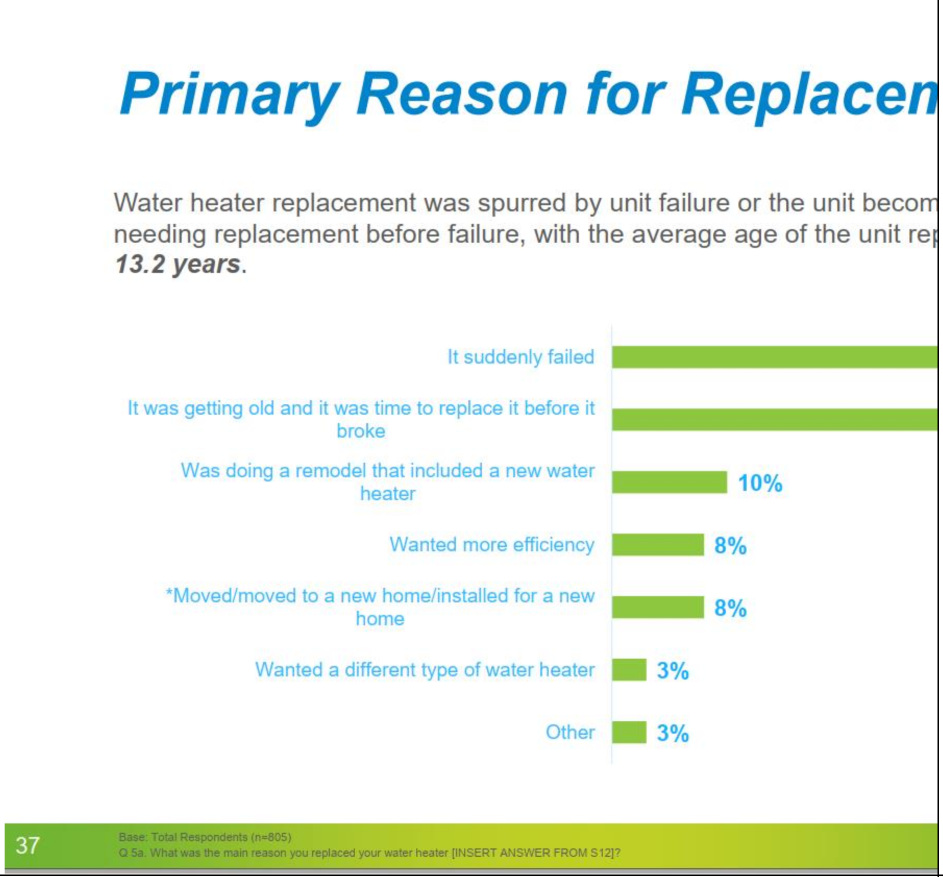	
		Slide 45 – Comparison to the 2019 CPA One point on the slide indicated “Lowered space heating DLC per unit kW impacts.” Please describe the previous and current values and what led to this result.	Slide 45: The previous study used a value of 1.74 kW, which was derived from a PSE pilot in a very specific part of its service territory (Bainbridge Island) that is over a decade old. The new value, 1.09 kW, is the same value used by the Council in its draft 2021 Plan’s demand response supply curves and originates from a

<table>
<tr><th>Feedback Form Date</th><th>Stakeholder</th><th>Comment</th><th>PSE Response</th></tr>
<tr><td></td><td></td><td></td><td>more recent evaluation of PGE’s program. We believe this value is more appropriate and applicable to PSE’s service territory than the Bainbridge Island pilot value.</td></tr>
<tr><td></td><td></td><td>Slide 49 – Distributed PV Methodology
While the Bass diffusion model is widely used, we have three concerns. First, it may not fully capture the anticipated value perceived by customers of hedging against future rate increases.
Second, it may not account for non-price factors driving customer adoption, for example, environmental responsibility. And third, because it is based on an annualized simple payback calculation, first-cost plays a deciding role.
We are unclear whether the methodology incorporates the NREL Annual Technology Baseline (ATB) values for future PV costs, or it relies on the previous Annual Energy Outlook estimates.
We have reviewed the recently issued 2020 ATB, and find that significant cost reductions have occurred compared even to the 2019 ATB for residential solar at their Seattle standard location.
The following table shows the life cycle cost of energy (LCOE $/MWh) values for 2020, 2025 and 2030. The cost decline trend throughout the decade is substantial, and as previously stated, we believe the midpoint between the Low and Mid-range (2019 ATB) or Advanced and Moderate range (2020 ATB) is the most appropriate for modeling purposes.

<table>
<tr><th></th><th>2020</th><th>2025</th><th>2030</th></tr>
<tr><td>2019 Low</td><td>117</td><td>77</td><td>39</td></tr>
<tr><td>2019 Mid</td><td>134</td><td>103</td><td>72</td></tr>
<tr><td>2020 Advanced</td><td>117</td><td>76</td><td>37</td></tr>
<tr><td>2020 Moderate</td><td>119</td><td>84</td><td>50</td></tr>
<tr><td>NWEC Proposed</td><td>118</td><td>79</td><td>44</td></tr>
</table></td><td>Slide 49: Due to the uncertainty regarding future incentive and tax credit availability, PSE plans to model several solar PV sensitivities, including the potential estimated by the Bass diffusion curve, as shown in slide 49 of the presentation.
Regarding the NREL price forecast, the results presented are based on the 2019 ATB cost forecast; the 2020 ATB data set was not yet publicly available at the time of our analysis; however, Cadmus proposes to update the BAU scenario to the 2020 NREL ATB moderate forecast and run a separate sensitivity using the 2020 advanced forecast.</td></tr>
<tr><td></td><td></td><td>Slide 49 – Achievable Potential Assumptions</td><td>Slide 49: This incentive is mostly energy value as solar pV does not contribute to PSE winter</td></tr>
</table>

Feedback Form Date	Stakeholder	Comment	PSE Response
		Please explain the choice of the $0.048/kWh incentive for the subsequent analysis. This amount appears to provide only capacity value and should also include energy value.	system peak. PSE will address this further with a sensitivity requested using an updated 2020 ATB data in place of the PSE incentive.
		Slide 51 – Distributed Solar PV Achievable Potential This chart only addresses the amount of potential new PV going forward. It would be helpful to provide additional information about what PSE has already attained over the last 20 years and adoption trends to date	Slide 51: The requested data will be included in the Consultation Update.
		Slide 66 – Distribution Efficiency Potential Is there an effective difference between volt/var optimization (VVO) and conservation voltage reduction (CVR)? What have been the results from pursuing CVR programmatically?	Slide 66: VVO has a mechanism to dynamically maintain the set point for the conservation voltage reduction even when growing number of distributed energy resources on the circuit. Whereas CVR was a more static system setting and the savings could be reduced with the penetration of more distributed energy resources which impact the electrical characteristics of the distribution system. So far, the CVR is working but looking into the future, VVO will likely become more important.
		Slide 69 – Stakeholder Feedback on DSR Sensitivities Proposed sensitivity 2 is for “Distributed Solar PV – with PSE ownership.” Since this would be a new program with many important elements and issues, please explain the basic concept and whether it would expand solar access to low and moderate income and other disadvantaged segments that would expand DSR resource potential.	Slide 69: PSE will include your suggestion provided during the webinar for a sensitivity with a lower cost curve. PSE will likely propose to replace the PSE incentive sensitivity with the lower cost curve sensitivity. The Clean Energy Implementation Plan (CEIP) would allow for discussions on how best to offer programs to disadvantaged segments of PSE customers.
7/20/2020	Michael Laurie, Watershed LLC	Do the load forecasts take into account the likelihood that commercial building occupancy will be significantly less than it was pre-COVID and that overall demand will likely be less for several years into the future because of	PSE responses by paragraphs and referenced slide numbers:

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		the economic impact of COVID and because many more people will be working from home permanently? If not why not? Do any of the efficiency and renewables estimates take into account that we may likely have a Democrat president and Democrat controlled Congress which will likely lead to significant federal incentives for more efficiency and renewables? Biden has put together a major Green New Deal Plan that significantly eclipses the federal spending on efficiency after the housing crash in 2008. If you have not taken this into account, what is your justification for ignoring what could be a huge impact on efficiency starting next year? Could you show us your calculations, inputs, and assumptions that you used to estimate the non-PSE programmatic conservation that will occur due to Washington legislation that has passed recently including new energy codes, C-PACER, CETA, commercial building performance standard, and more. This is critical because if this is underestimated it could lead to overbuilding supply side resources. It is not helpful to anyone to know that you will include it in the modeling. Please show us the numbers and details even if that means showing us a simplification of how the model will deal with it. To me a simplification means at least at Excel workbook that makes estimates of the efficiency savings that will occur due to each program and it documents what those assumptions are based on. Ideally a 3rd party should carry out energy modeling of base case energy use and reduced energy use due to these programs for several representative building types as was done in the study linked below on the energy code impacts. https://www.sbcc.wa.gov/sites/default/files/2020-04/SBCC-BaselineStudy_FinalReport-APPENDIX%20E_Part-2_2-20200323.pdf Have you looked at the Rocky Mountain Institute's case study of the major retrofit of the Empire State Building to include the measures they implemented in your analysis of what is technically feasible? And are you working to ensure that the measures implemented in that building are studied and encouraged in the commercial buildings of PSE customers. And if not,	Per our economic forecasts based on Moody's and other regional sources (which include assumptions about the effects of the pandemic), we anticipate slower commercial customer additions and a small shift of load from the commercial class to the residential class due to unemployment and employment contractions in the medium term (i.e., people spending more time at home). The load forecast is based on the assumption that the pandemic state is temporary (resolved before 2022), however, we acknowledge there may be permanent behavioral changes, post-pandemic, and will adjust the forecast when legitimate steady state becomes more clear. The load forecast details will be further discussed at the September 1 webinar. The IRP is an iterative, long term planning process. Changes to federal standards will be adopted in the assumptions when passed into law. The draft report will include a more detailed accounting of non-programmatic conservation that will occur from Washington State energy legislation. PSE is familiar with the major retrofit of the Empire State. Our study is focused on PSE service area conditions, fuel mix, building & system vintages, labor costs, etc. PSE implementers are required by state law (Energy Independence Act) to implement cost

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		why are you leaving so much conservation on the table when others like in New York are taking action on it? https://www.esbnyc.com/sites/default/files/ESBOverviewDeck.pdf What is the relationship between the CPA and IRP effort versus program implementation? Are the program implementers at PSE required to show a good faith effort to carry out what the IRP concludes is cost effective? If so, is there a publicly available report where the implementers document that? If not why not?	effective amount of conservation coming out of the IRP. They work with a stakeholder group called the conservation resource advisory group (CRAG) to set the targets using the IRP cost effective conservation results, and they file the Biennial Conservation Plan with the WUTC, which is available to the public.
		Slide 36 includes one measure called "Whole Home". Whole home what? What is that?	Slide 36: The Whole Home measure applies to new single family and manufactured home and is an incentive based on achieving 20-30% energy efficiency over the state energy code baseline.
		Slide 39, Back to my point about considering a likely Democratic federal administration in your analysis, I think it is critical to consider that there will be a lot more new federal standards when and if that happens. Why aren't you including this in one of your options going forward?	Slide 39: Typically, most conservation potential assessments, including those performed by the Northwest Power and Conservation Council, do not attempt to predict the impact of non-existent future federal standards or state and local building codes.
		Slide 45 - Agree with Don Marsh's point. PSE please explain what thinking and evidence led to you reaching a different conclusion than other utilities reached on this subject.	Slide 45: The explanation regarding customer acceptance was listed solely with respect to smart appliance direct load control. We are not currently aware of any secondary research that indicates customers' acceptance of having smart appliances controlled by their local utility. The most recent Smart Electric Power Alliance 2019 Utility Demand Response Market Snapshot included a survey question that indicated 0% of 95 utility survey respondents indicated that voice-enabled smart home devices have been integrated into new or existing demand response programs.

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		Have you considered the possibility of some uses of natural gas will be banned in new construction as has happened in a number of jurisdictions in California? If not why not? Could you do a sensitivity analysis of conservation achievable if conservation can be done without a loss of revenue to PSE. I am thinking here about the MEETS approach. (Metered Energy Efficiency Transaction Structure): This is efficiency that also does not have to meet PSE's cost effectiveness bar because it is not PSE paying for it as an alternative to a gas plant or renewables. It is a private investor group doing it to make money from efficiency with no loss of revenue to PSE. After a quick review of the PSE July 14th presentation this looks to be one of the Achilles heals of PSE's effort because they are focused on carrying out cost effective, technically feasible conservation that does not have barriers. But MEETS includes conservation that does not have to meet their cost-effectiveness criteria and that will not be up against the typical barriers that most conservation is limited by. Why isn't PSE willing to at least carry out a pilot project of this deep retrofit approach like Seattle City Light is currently doing? And a sensitivity analysis of conservation potential if conservation spending was recognized as capital spending, thus allowing PSE to make a profit on conservation spending. Some people have proposed the idea that conservation spending be considered capital expenditures because that would allow PSE that make a profit on it. How would this impact conservation spending? I think it could have a huge impact leading to so much conservation spending that the case for new natural gas plants would be unnecessary. Thank you for your time on these important issues. All the best.	PSE is considering a fuel conversion sensitivity from gas to electric. The possible scenarios and sensitivities will be discussed at the August 11 webinar. PSE already has a decoupling mechanism is place: https://www.utc.wa.gov/docs/Pages/PSEDecouplingUE121697.aspx It is primarily a delivery mechanism for conservation measures and this discussion belongs in the design and implementation of programs. Concerning the idea to run a sensitivity on earning a return on conservation, we can discuss this during the August 11 webinar on scenarios and sensitivities (electric and gas).
7/21/2020	Kyle Frankiewich, WUTC	**Commission Staff Feedback for Puget Sound Energy 2021 IRP Webinar #4: Demand Side Resources – July 14, 2020** Questions and comments from presentation:	PSE responses to questions and comments by referenced slide number:

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		• Slide 11: Elizabeth explained that one advantage of Plexos is that the program is open-source, so all resources are visible and able to be coded in. Accurately representing these unique resources - coding these inputs - then becomes critical. Please share the parameters used for the various DR resources, as well as any documentation used to support the parameters used.	Slide 11: PSE has not finished setting up the Plexos model and the DR programs have not been coded yet. The information will be available at a later date.
		• Slide 13: Where did PSE's figures come from? What went into them? Are they stale or is this a fresh analysis for the 2021 IRP? Please provide the work papers supporting PSE's deferral benefit estimates.	Slide 13: PSE updated the analysis for the 2021 IRP and is currently assessing what information can be made public. Additional information may be provided in the Consultation Update.
		• Slide 18: It appears that CCP is the only type of alternative rate design approach explored within CADMUS's CPA. This may be acceptable if PSE intends to fully explore the potential for TOU and dynamic rates elsewhere in the IRP. What aspect of PSE's work plan includes this piece?	Slide 18: We don't test rate designs in the IRP. The CPP program assumes that the company will attain a time differentiated rate in the near future. That is an assumption upon which the CPP is based in the IRP. The CPP program may or may not be the driver for a future change to a time differentiated rates.
		• Slide 27: Are all costs and benefits levelized by PSE's WACC? If so, it may be more appropriate to model the carbon emissions cost (and carbon emission reduction benefits) using a 2.5% discount rate to align with U-190730. (may be covered in 7/21 meeting)	Slide 27: Yes all costs are levelized using the WACC. U-190730 relates to the use of inflation factors in adjusting the SCGHG. We have done a sensitivity in the past using the social discount rate and we can consider one in this IRP. The scenarios and sensitivities will be discussed at the August 11 meeting.
		• Slide 29: Baselines should rightly be adjusted for new water heater standards; does the EE and DR program implementation side of PSE have the capability to acquire these opportunities?	Slide 29: PSE needs clarity concerning this question. PSE will be reaching out to WUTC to gain some insight.
		• Slide 35: Please describe the whole home measure category. What is weighted average levelized cost? What is being weighted and averaged? Does this imply a market forecast with hourly prices? I didn't get to ask in the interest of time.	Slide 35: The whole home measure relates to whole building performance incentive to build 20-30% above the WA state energy code. Built Green program: The table on slide 36 presents the results for different residential measure categories, some of which are comprised of

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			many different individual measure applications; for the whole home measure category, this would include new single family and manufactured homes that are either 20% or 30% better than code. Therefore, we also created weighted average levelized costs, which is an average levelized cost for each individual measure application, weighted by that application's total achievable technical potential.
		• Slide 42: Please describe the difference between CPP and behavioral DR. Is behavioral DR simply asking/informing?	Slide 42: Critical peak pricing (CPP) is typically included in a tariff whereas behavioral demand response, which is neither time of use nor critical peak pricing, is a demand response program that notifies customers day-ahead via text or email of an upcoming event and encourages them to save energy during a specific time horizon.
		• Slide 44: This is a very useful graph. What are kW-yr costs like on supply side, generally? For peaker / CCCT / 10 MW battery? How do these kw-yr figures compare to the $/kWh measures above? Or is that EE apples and DR oranges? (see recommendation about Pacific Power's aborted idea on calculating the capacity value of EE)	Slide 44: PSE does not have the levelized cost of supply resources, it is calculated at the end of the process using the model outputs.
		• Slide 46: Why limit CPP participation? Can residential customers with gas space heat provide value through a DLC program?	Slide 46: Cadmus is not aware of any gas CPP program. Part of the limitation is that the two primary gas end uses (water and space heating) can also be directly controlled whereas CPP is not a firm resource. Another part of the limitation is that gas is traded on a daily basis and system peaks are daily. If a CPP program is applied to end users, the daily use may not change. The gas use after the CPP event may be higher to bring the space or water temperature back to the set point.

Feedback Form Date	Stakeholder	Comment	PSE Response
		• Slide 49: Does PSE intend to generate other components of the DER assessment required under CETA? Do empirical data support the use of a homo economicus assumption about customer adoption of solar? What is a Bass diffusion model function? A key input to this analysis is the falling cost of solar. Does that input align with PSE's supply-side solar assumptions? Does PSE intend to explore the value of customer-sited (and possibly customer cost-shared) energy storage, especially paired with solar? This seems like an important DER to fully understand. The impact of alternative rate design paired with DERs must also be fully analyzed.	Slide 49: PSE will discuss distributed energy resources (DER) at the August 11 meeting. Depending upon the study, empirical data likely indicate a number of factors influencing both commercial and residential customer solar adoption, including estimated payback. The Bass diffusion model function is a Bass diffusion model variant that models customers' sensitivity to payback and the annualized simple payback for each year of the study horizon. Utility-scale and customer-sited solar PV costs vary widely and are not the same; customer-sited PV costs also vary between residential and commercial customers. In both cases, the PV analysis includes a forecast of future solar PV prices, which do decline substantially over the study period.
		• Slide 50: Where does $0.048/kWh rate come from? Does changing this rate yield dramatically different adoption rates? Does this rate align with the company's PURPA rates? If not, what is included here that is not included within the company's PURPA avoided costs?	Slide 50: We have estimated the avoided cost based on the draft 2019 IRP work we did. This lines up more with cost effectiveness used for customer programs. This is not seen as a PURPA avoided cost. Based on feedback from you and NWEC during the webinar, we will eliminate this PSE incentive sensitivity and consider a lower cost curve sensitivity in its place.
		• Slide 60: Seems gas EE costs have come down while total potential has grown. Why?	Slide 60: The potential has gone up due to market changes that impacted couple measures. Gas potential is lumpy in that changes in one or two measures can have an impact on the supply

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			curve. The lower gas costs don't affect the measures costs, but will come into play when we run the IRP model to determine the cost effective amount of conservation.
		• Slide 61: As with EE, please explain what is being weighted and averaged in the levelized cost column. Do these calculations include all quantifiable non-energy benefits? Appears so given that aerators have a negative cost. What NEIs were included?	Slide 61: Individual measure applications are being weighted within large measure categories. For example, individual measures may have varying incremental costs and/or energy savings depending on which housing segment is being treated or the baseline measure it is replacing. The individual measure levelized costs are weighted by each measure's total achievable technical potential. These calculations do include all quantifiable non-energy impacts; measures with low incremental costs but significant NEIs, like aerators, may have negative levelized costs.
		• Slide 66: How long did it take for first 17 substations? What controls are being adopted in 2022? Is the tech not ready to be adopted now or in 2021? Has PSE estimated the added cost of pulling these projects forward in time, i.e. to get 24 aMW of savings before 2026 instead of by 2034? Is that option (and the corresponding added cost) selectable by the resource optimization model? Do these upgrades also enable more solar and other DER resources?	Slide 66: The Advanced Distribution Systems Management (ADSM) system will be installed in 2022 and it will ensure stability and accommodate more DERs on the system, and will allow additional savings in the distribution efficiency measures. No, early completion is not adjustable inside the IRP model.
		• Slide 67: why is levelized price the appropriate way to bundle? What does 20yr vector mean? is a 'bundle' of subsidized private solar at small cost the best way to model distributed PV as a selectable resource? What does 'applied in the portfolio models' mean?	Slide 67: The levelized cost is standard industry practice for creating supply curves. A vector is a 20 or 24-year stream of savings that is used as the input in the portfolio model and it is a resource option available in the first year of the study. Distributed solar is a must take resource and is not being "selected." The application of SCGHG in the IRP models was addressed at the July 21 webinar.
		• Slide 68: It seems like there is a lot of analysis that is being described in these bullet points. How is a DR program group's ELCC	Slide 68: PSE will discuss the resource adequacy model and the effective load carrying

Feedback Form Date	Stakeholder	Comment	PSE Response
		determined? Are other resources also decremented based on an ELCC analysis? What is the ramp-up time for a DR program? What are the DR program sizes available to the portfolio model? How did PSE determine that these sizes are appropriate?	capacity (ELCC) of demand response (DR) and other resources at the September 1 meeting. The ramping and quantity is shown and discussed on slide 44 and additionally on slide 84 in the appendix. The amount of DR is the result of the potential assessment.
7/21/2020	Kyle Frankiewich, WUTC	Recommendations:	PSE responses concerning recommendations by number:
		1. Equity analysis in IRP: CETA requires an equity assessment within the IRP, as described in RCW 19.280.030(1)(k). This requirement is not waivable, and is not on hold while rulemakings and Department of Health's cumulative impact analysis work is ongoing. Modeling is a decision support tool, and system needs should consider all constraints and requirements, including equity needs. At the very least, PSE needs to assess whether it's selected portfolio increases or decreases disparities in the geographic distribution of system benefits and burdens. This is a very different challenge from past IRPs, which is why it seems like a good idea to discuss how to approach this new challenge early and often. How does PSE plan to countenance this equity constraint? Please consider adding a separate IRP meeting to discuss equity issues and the company's proposed approach for assessing equity impacts.	1. Thank you for the recommendation. PSE is still assessing the best process to ensure that equity is appropriately addressed through the 2021 IRP.
		2. CPA before load forecast: Many participants expressed concern about this topic. To assuage these concerns, PSE should compare the preliminary load forecast used as a CPA input with the finalized forecast to see whether the CPA results are reasonable. a. We also agree with commenters that changes from 2019 CPA to 2021 CPA are hard to understand if most of the shifts in conservation potential are brought about by changes in the load forecast. b. Also, we want to recognize the unavoidable bind PSE is in – if PSE had started with imperfect load forecast that didn't	2. (a) The impact from the changes to the load forecast are relatively small. The major changes were due to updates to the measures themselves, and their savings assumptions. Three of the major changes were discussed on slide 34. (b) PSE used a draft version of the 2020 load forecast in the results presented on July 14th. We expect the final will be the same as the draft and if not, then very close to it. In the event that

Feedback Form Date	Stakeholder	Comment	PSE Response
		include finished CPA figures, participants may wonder why preliminary figures were being presented when they aren't fully baked.	there is a major change in the final we will inform the stakeholders of the change. In either case, Cadmus will update its analysis based on the final load forecast and we will detail the changes to the potential based on the final forecast.
		3. Ramp rate for discretionary EEMs: Some commenters have noted that the 10 year ramp for discretionary EEMs is arbitrary. I don't know that it's wrong, but it would be good to hear why 10 yrs is more appropriate than 4 or 6 yrs, especially knowing that the value of conservation may (or may not!) jump in 2026 and 2031 due to CETA's restrictions on fossil-based supply-side resources. Some sensitivities to see the impact of adjusting these ramp rates would also be helpful.	3. The 10 year ramp was determined around the 2007 IRP. PSE will consider the faster ramp rates of 6 years and 8 years as sensitivities. This topic will be discussed further at the August 11 webinar.
		4. Uncertainties regarding customer acceptance (of DR, CPP, solar): these assumptions are soft and fungible; PSE could shift perceptions of programs if it decided it was worth the time and investment. Should vet these assumptions based on empirical data elsewhere and assumptions of other utilities.	4. The major customer uncertainty for demand response listed was that of smart appliance direct load control. We are unaware of any fully implemented program or evaluation of customer acceptance of this control technology. For other demand response products, the program participation rates – which account for likely customer acceptance – are all based on secondary research of similar programs from other utilities and have been checked against regional assumptions on the Council's 2021 Plan draft demand response supply curves and other recent, NW utility IRPs.
		5. Sensitivities around private solar: install price; incentive offering; including knock-on effects	5. PSE will be doing a sensitivity with a lower cost curve of solar PV. Additional discussion regarding the sensitivities will occur at the August 11 meeting.
		6. Scenario banning new gas use: I'm not expecting the company to plan around this possibility, but understanding how the plan would have to pivot if a ban or partial ban was put in place can only be helpful.	6. PSE will be discussing portfolio sensitivities at the August 11 webinar and stakeholders will have an opportunity to provide feedback regarding the sensitivities that should be

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			included. One of the sensitivities is a fuel conversion from gas to electric, we are not looking at a gas ban scenario.
		7. TOU and dynamic rates: Please clarify when and where these options will be analyzed.	7. These options are analyzed outside the IRP in the rates and regulatory group of the company.
		8. DR water heaters: Fred with NWEC's observations on the rough scale of this potential resource are persuasive. Please reconcile the forecast in this CPA of about 60 MW total over 20 yrs with his back-of-the-envelope estimate of about 25 MW a year.	8. Slide 44 shows 71 MW of residential water heat direct load control. The 71 MW are achievable technical potential which includes an assumption that program participation is equal to 25% of the eligible customer population (i.e. residential customers with electric water heating). This program participation value is the same assumption employed by the Council in its draft 2021 Plan demand response supply curves. Dividing the 71 MW by 25% equals about 284 MW of technical potential, a value similar to NWEC's estimate.
		9. DR and conservation capacity cost as net of energy savings: In its 2019 IRP, Pacific Power briefly proposed a novel way to derive the capacity cost of EE and DR resources. They used a 20yr hourly energy price forecast and an EEM's load curve to project whether the EEM was cost-effective purely on an energy basis. When it was not, they took the incremental $/MWh cost relative to their energy price forecast and paired that with the EEM's load curve again to determine a $/kW-yr price for the capacity component of an EEM's benefit. I don't want to see this implemented as a way to determine cost-effectiveness, but as a way to value the capacity value of an EEM, it may be useful. Would the company be willing to explore this approach?	9. We input the conservation supply curve as an hourly load shape and the portfolio model takes into account both the capacity and energy value of the energy efficiency in selecting resources. The demand response is input as a capacity resource and its primary value is due to capacity. The ancillary benefit streams will be netted out of the cost.

Feedback Form Date	Stakeholder	Comment	PSE Response
Questions not answered during the webinar			
7/14/2020	Brian Grunkemeyer, FlexCharging	Question queued up for slide 36: I don't see anything about Demand Flexibility approaches. Specifically, there's no EV load management measure, and it's unclear whether the Heat Pump Water Heater measure is taking advantage of all the great work the BPA has been doing on aggregating water heaters as Demand Flexibility devices.	Slide 36 presents the energy efficiency potential results for the residential sector. It does not include load management; however, slides 41 through 47 cover the demand response portion of the potential assessment, which includes electric vehicle service equipment direct load control. Slide 46 shows that residential water heating direct load control is the single largest end use resource for demand response potential and includes both grid-enabled electric resistance water heaters and heat pump water heaters, both of which are ANSI/CTA-2045 capable. The underlying analysis uses per unit kW impact assumptions from the BPA/PGE study.
7/14/2020	Don Marsh	Documentation of PSE's models and assumptions is so important because some of the conclusions PSE comes to seem to be at variance with what is happening with other utilities across the country. For example, Pacificorp is going much more for battery storage than PSE is. Why is that? Is there something different about PSE's service territory? We need to understand.	PacifiCorp service area is very different than PSE's service area. Their plan shows utility scale battery storage which is also included as a front of the meter option in the 2021 IRP.
7/14/2020	Kevin Jones	Will the CADMUS analysis be re-done if there are significant issues with the PSE load forecast? Technical advisors have typically raised concerns about PSE load forecast. How are these results valid?	If errors are found that need to be corrected, then PSE will make best efforts to make those corrections.
7/14/2020	Court Olson	We would like to know when we can plan on hearing a new analysis that includes the heating fuel switching trend that is growing. This is a big flaw in the analysis. What future session will this be presented in?	Fuel switching is being included as a sensitivity and will be discussed at the August 11 webinar on scenarios and sensitivities.
7/14/2020	Bill Westre	Ramp rates - Have other utilities used shorter ramp rates?	PSE is not aware of shorter ramp rates being used.
7/14/2020	Michael Laurie	Have you looked at the case study of the major retrofit of the Empire State Building to include the measures they implemented in your analysis of what is technically feasible?	PSE is familiar with the major retrofit of the Empire State and our study is focused on local

Feedback Form Date	Stakeholder	Comment	PSE Response
			NW (actually PSE service area) conditions, fuel mix, building & system vintages, labor costs, etc.
7/14/2020	Elyette Weinstein	What percentage of annual contributions does PSE contribute to the NW Energy Efficiency Alliance?	According to the filing with the WUTC (Docket Number: EES0012019), PSE paid approximately $7.2 million to NEEA in 2019 and their total utility contributions were approximately $40 million (https://neea.org/annual-report/2019
7/14/2020	Court Olson	How is the unique efficiency impact for an aggregation of measures going to be used to adjust the PSE future efficiency forecast? This is important as future CETA deadlines and C-PACER programs ramp up and deep efficiency improvements catch on in the buildings market place. The 2021 IRP must take this into account, so when will we see appropriate revised efficiency forecasting?	PSE appreciates your observation that we are not using bundling of measures in the CPA. The conservation supply curve is ordered lowest cost to highest cost so we can test the marginal cost resource to determine the cost effective amount of conservation. We will not have a forecast with these bundles in the CPA. However, what you are suggesting can be considered on the implementation level with programs, and the CPA does not prevent this in any way. Programs can be designed to include highly cost-effective measures with hard to reach measures or deep measures.
7/14/2020	Michael Laurie	What is the relationship between the CPA and IRP effort versus program implementation? Are the program implementers at PSE required to show a good faith effort to carry out what the IRP concludes is cost effective? If so is there a publicly available report where the implementers document that?	PSE implementers are required by state law (Energy Independence Act) to implement cost effective amount of conservation coming out of the IRP. They work with a stakeholder group called the conservation resource advisory group (CRAG) to set the targets using the IRP cost effective conservation results, and they file the Biennial Conservation Plan with the WUTC, which is available to the public.
7/14/2020	Kevin Jones	Gurvinder - you did not really answer my question - would PSE provide the load data used in the CADMUS analysis? Will this be the same or different than the load forecast provided in September? If different we would like to	The load forecast was provided as a draft as it takes a lot of effort to get the forecast completed, so there is a small chance that the load forecast may see some minor changes from what was

Feedback Form Date	Stakeholder	Comment	PSE Response
		understand the differences. If the same, why will PSE not provide the data now?	used in CPA versus what is finally approved. But the load forecast change will not and does not have a material impact on the CPA numbers. If there is a change in the load forecast from the one used in the CPA, we will inform you of that.
7/14/2020	Don Marsh	Slide #30. How do the 2023 values compare to NWPCC assumptions? How do they compare to assumptions for neighboring utilities, like Seattle City Light? They seem a little low to me.	These values have to be compared within context. A high number can also indicate that the utility has not being engaged in aggressive conservation in the past and thus a lot of conservation still remains. The numbers for Seattle City Light are at the technical potential level, and if one uses the 85% achievability factor assumed in the SCLs numbers for achievable technical potential are as follows: Residential = 21%, Commercial = 20%, and Industrial = 7%. PSE's corresponding numbers are 18%,18% and 8%.
7/14/2020	Court Olson	You missed the legislating update for HB2405 which put C-PACER into law. This needs to be included in your analysis. When will your analysis be adjusted accordingly?	Thank you for bringing this to our attention, the next legislation seems to have passed this spring. Any impacts will be reviewed and PSE will provide a discussion in the IRP book of the implication to the next CPA.
7/14/2020	Joni Bosh	Repeating my question from slide 24 here again - If measures are bundled by levelized costs, how do you plan to reflect/capture peak energy values? By measures? By bundles? Slide 27	The measures are shaped using 8760 hourly shapes before they are bundled. The region has been relying on ELCAP data library and some shapes from the RBSA. Thus the bundles are also an aggregated 8760 hourly shape, where the peak is part of the shape.
7/14/2020	Court Olson	Your commentary thus far indicates that several things were overlooked and not included in estimating the achievable energy efficiency over the next twenty years. When will these projections be revised to include the increasing trend of deep efficiency improvements which we expect over the next twenty years?	The CPA has a comprehensive look at all possible measures that could be done. The idea of deep retrofits belongs in the implementation side, whereby the aggregation of very cost-effective measures with not so cost-effective

Feedback Form Date	Stakeholder	Comment	PSE Response
			ones can lead to more comprehensive retrofits. The programs teams are working with pay for performance measures and engaging with them may answer the questions you are posing here.
7/14/2020	Kevin Jones	Slide 33: Is the 26% to 8% drop in achievable Industrial technical potential due to industrial to commercial reclassification?	Yes.
7/14/2020	Don Marsh	Slide #34: I think you're saying that most of the drop in electric potential is because of lower growth in various categories. So the load forecast should be significantly lower than we saw in 2019. But for now, we just have to guess. Like blind men describing an elephant.	The load forecast is not the major driver in the reduced conservation on slide 34. It is not a factor in the items discussed on this slide. Load forecast will be discussed at the September 1 webinar.
7/14/2020	Court Olson	Slide 34 seems to only consider new construction. Some of us expect an increasing likelihood of retrofitting existing buildings. It appears that you are missing this likely occurrence over the next 20 years which will likely eclipse the savings impacts from more efficient new buildings. When will your forecast be adjusted to accommodate this likely future trend? To follow up on my question on air leakage consideration, please provide the data source for the detailed envelope factors that Camus says that they use. Thanks.	PSE appreciates your observation that we are not using bundling of measures in the CPA. The conservation supply curve is ordered lowest cost to highest cost so we can test the marginal cost resource to determine the cost effective amount of conservation. So we will not have a forecast with these bundles in the CPA. However, what you are suggesting can be considered on the implementation level with programs. Programs can be designed to include highly cost effective measures with hard to reach measures, or deep measures. The underlying air leakage assumptions were derived from various Regional Technical Forum unit energy savings workbooks including, for example, the Residential Single Family Weatherization workbook, v4.1: https://nwcouncil.app.box.com/v/ResSFWeatherization-v4-1
7/14/2020	Doug Howell	Slide 26. That does not answer the question about why can't PSE further accelerate the ramp rate from 10 years to six or eight years.	You have requested 6 and 8 year ramping as sensitivities and PSE has included your request

Feedback Form Date	Stakeholder	Comment	PSE Response
			in the list of sensitivities. Further discussion will occur at the August 11th meeting.
7/14/2020	Court Olson	The answer to my question on the 10 year life for measures rather than 20 years, the assumption that measures will only have a weighted average of 10 years is incorrect in my experience. This needs to be revised. When can we expect to see this impact period extended from 10 years to 20 years?	The CPA uses standard measure life data for equipment, as used by the regional technical forum (RTF), NWPCC, NEEA, etc. You are correct that often the equipment is used beyond its useful life. In those cases the efficiency also degrades over time. The CPA assumes that equipment is replaced at the end of its life with same efficiency as was installed in the first year.
7/14/2020	Michael Laurie	Slide 36 includes one measure called "Whole Home". Whole home what? What is that?	The whole home measure relates to whole building performance incentive to build 20-30% above the WA state energy code. Built Green program. https://www.pse.com/rebates/new-construction-grants/high-performance-homes
7/14/2020	Michael Laurie	Slide 39 Back to my point about a likely Democratic federal administration, I think it is critical to consider that there will be a lot more new federal standards when and if that happens.	The IRP is an iterative, long term planning process. Changes to federal standards will be adopted in the assumptions when passed into law.
7/14/2020	Kyle Frankiewich	slide 42: what's the difference between CPP and behavior DR? If behavioral DR is similar to home energy reports, is it effectively just asking / informing customers of the benefit of shifting load?	Critical peak pricing (CPP) is typically included as a tariff whereas behavioral demand response, which is neither time of use nor critical peak pricing, is a demand response program that notifies customers via text or email of an upcoming event and encourages them to save energy during a specific time horizon.
7/14/2020	Kate Maracas	Slides 42-43: To what extent does PSE rely on demand response aggregators to deploy the DR products? Could broader use of aggregators increase customer adoption?	At the present, PSE has only conducted pilots demand response programs. PSE will use a request for proposals (RFP) process to solicit the best offerings and programs for its customers, and bidders will have the opportunity to aggregate their DR offerings.
7/14/2020	Don Marsh	Slide 45, does "behavioral load response" = time of use rates? Or is this just critical peak pricing?	Slide 45 mentions behavioral demand response, which is neither time of use nor critical peak

Feedback Form Date	Stakeholder	Comment	PSE Response
			pricing. Rather, it is a type of demand response program that notifies customers day-ahead via text or email of an upcoming event and encourages them to save energy during a specific time horizon.
7/14/2020	Kate Maracas	Slides 42-44: do many of these programs rely on AMI (automated metering infrastructure)? If so, is investment in AMI an impediment to broader customer adoption?	Some do rely on AMI, but AMI helps in the measurement and communication for all programs. AMI deployment is not an impediment. PSE is expected to complete its AMI deployment by 2023, one year into the start of this CPA study period. https://www.pse.com/pages/meter-upgrade
7/14/2020	Kevin Jones	Slide 45: Is uncertain customer acceptance a CADMUS or PSE assumption and what is the basis for the assumption?	Thank you for your comment. The explanation regarding customer acceptance was listed solely with respect to smart appliance direct load control. We are not currently aware of any secondary research that indicates customers' acceptance of having smart appliances controlled by their local utility. The most recent Smart Electric Power Alliance 2019 Utility Demand Response Market Snapshot included a survey question that indicated 0% of 95 utility survey respondents indicated that voice-enabled smart home devices have been integrated into new or existing demand response programs.
7/14/2020	Doug Howell	Demand Response: Do the DR benefits include: avoided generation and TX upgrades; avoided distribution upgrades; storage function; line loss reduction from energy savings; ancillary services at generation level such as frequency regulation and spinning reserve; and ancillary services for distribution of voltage control?	Yes. Please refer to the pie chart from Brattle group's presentation at the UTC DR workshop on slide 68. The majority, as in more than 95%, of the savings from demand response accrue from capacity, avoided transmission and distribution, and energy savings. Then there are the other benefits you mention: ancillary services, which include regulation and spinning reserves. In this IRP we will use the Plexos flexibility model to

Feedback Form Date	Stakeholder	Comment	PSE Response
			estimate the ancillary benefits associated with the DR programs being considered in the IRP.
7/14/2020	Court Olson	Not including the potential for demand control on smart appliances misses a DR potential. Can this potential be included in a revision to the DR calculations?	No. See below response to Michael Laurie's question reference slide 45.
7/14/2020	Don Marsh	Don Marsh Comment: Slide 45 - "uncertainties regarding customer acceptance" is PSE's standard explanation. However, many utilities find customers love demand response programs that provide lower monthly bills. PSE is using assumptions that are decades out of date.	Thank you for your comment. The explanation regarding customer acceptance was listed solely with respect to smart appliance direct load control. The sixteen demand response products included in the study all explicitly assumed some level of customer acceptance, typically reflected in program participation assumptions that are included in the achievable potential estimation.
7/14/2020	Michael Laurie	Slide 45 - Agree with Don Marsh's point. PSE please explain what thinking and evidence led to reach a different conclusion than other utilities reached.	We would welcome any additional information regarding utilities currently offering demand response programs for smart appliances and/or any evaluations of these programs. The most recent Smart Electric Power Alliance 2019 Utility Demand Response Market Snapshot included a survey question that indicated 0% of 95 utility survey respondents indicated that voice-enabled smart home devices have been integrated into new or existing demand response programs.
7/14/2020	Kevin Jones	Slide 38: What is the basis of the assumption that energy efficiency occurs before Demand Response? What is your estimate of delayed DR employment while waiting for EE upgrades?	Whether we do demand response first or energy efficiency, there is an interaction between the two. So we have to account for it. Even if demand response takes place before, during or after (as assumed here) energy efficiency we need to account for the reduced load due to the interaction.
7/14/2020	Court Olson	Slide 49: Where to you get your PV market penetration function for each year?	It is a relatively, commonly-used Bass diffusion model function that measures a customer's

Feedback Form Date	Stakeholder	Comment	PSE Response
			sensitivity to payback and the annualized simple payback for each year of the study.
7/14/2020	Court Olson	Slide 59: Could you please define what you mean by combined heat and power?	Combined heat and power (CHP) is when a customer installs a generation system whose waste thermal heat is recovered for use to serve thermal load on site. By recovering the waste heat from the generation process, you increase the overall efficiency of the CHP.
7/14/2020	Court Olson	Slide 60: Are you projecting a decline in natural gas use due to switching to heat pumps? If not, when will you adjust your calculations to include this trend?	We have not included this. It is not cost effective to convert to heat pumps, unless one is doing an end of life replacement, in which case the incremental costs associated with equipment and electrical service upgrades may or may not be cost effective. We are keeping an eye on this conversion, but don't see much natural conversions to date that will have a meaningful impact on our gas loads. A major shift will likely be affected through legislative mandates, which are not presently on the books and have not been included in the forecasts. Finally, we are considering a sensitivity at the August 11th webinar.
7/14/2020	Michael Laurie	Slide 62: Have you considered the possibility of some uses of natural gas will be banned in new construction as has happened in a number of jurisdictions in California?	We include codes and standards that in the books at the time of the CPA. At the moment we don't have any laws banning natural gas, now or to go into effect in the future. Thus, we have not included anything presently. We will do this again in a couple years and have the chance to review any legislation updates that ban natural gas and can include that accordingly.
7/14/2020	Fred Huette	for slide 63: is there an effective difference between volt/var optimization (VVO) and conservation voltage reduction (CVR), if so has PSE looked specifically at CVR	Yes, PSE has typically just done CVR, but now with the Advanced Distribution Systems Management (ADSM) infrastructure roll out, CVR is done in combination with the reactive power

Feedback Form Date	Stakeholder	Comment	PSE Response
			management on the circuit. Since we are now doing both volts and vars, it’s called VVO.
7/14/2020	Kate Maracas	+1 to Don Marsh. Also, the increased capabilities of grid-forming inverters that will inevitably be deployed after implementation of IEEE 1547 standards will have a significant impact on solar PV's (distributed and utility scale) ability to provide flexibility and ancillary services. How is PSE considering both the cost reductions and advanced technical capabilities?	The analysis currently does not consider the capability of grid-forming inverters; however, PSE and its contractor are monitoring the implementation of IEEE 1547 interconnection standards and may consider inclusion of the impact of these technologies in the next IRP.

PSE IRP Consultation Update
Webinar 4: Demand-side resources
July 14, 2020

8/04/2020

The following consultation update is the result of stakeholder suggestions gathered through an online Feedback Form, collected between July 7 and July 21, 2020 and summarized in the July 28 Feedback Report. The report themes have been summarized and along with a response to the suggestions that have been implemented. If a suggestion was not implemented, the reason is provided.

PSE also thanks Joni Bosh, Fred Huette and Amy Wheeless of Northwest Energy Coalition (NWEC) for meeting with PSE staff on Juy 29 to help further clarify their questions and suggestions.

Electric Vehicles – Demand Response Program

PSE received feedback from Brian Grunkemeyer and Rob Briggs (Vashon Climate Action Group) concerning the high levelized cost assumption of the DR program for electric vehicles and requested Cadmus to provide more details on their estimate.

Cadmus' EV estimate of $300 from the Regional Technical Forum (RTF) study is reasonably close to the cost data that Brian provided on July 31, 2020 of $250 per participant. The other costs that are included in the $362 levelized cost are detailed in the table below:

Parameters	Units	Values	Notes
Setup Cost	$	DLC: $150,000	Assuming 1 FTE to set up the program.
O&M Cost	$ per year	DLC: $150,000	Assuming 1 FTE.
Equipment Cost	$ per new participant	$300	The Regional Technical Forum's researched incremental equipment cost of networked 240V level 2 charger compared to non-networked level 2 charger is $287 (Shum 2019).
Marketing Cost	$ per new participant	DLC: $30	Assuming this product requires higher marketing cost than the BPA assumption (Cadmus 2018a) for DLC products: $25 per new participant.
Incentives (Annual)	$ per new participant	DLC: $25	In line with incentives for residential DLC space heat products.
Attrition	% of existing participants per year	5%	In line with BPA assumption (Cadmus 2018a) for DLC products.
Eligibility	% of segment/	36%	The number of EV owners is aligned with the study's assumptions for energy efficiency. The proportion of EV owners that already have a residential 240V AC level 2 charger (64%) is based on research by the Regional Technical Forum (Shum 2019).
Peak Load Impact	kW per participant (at meter)	0.34	Based on 2021 Plan Workbook "Inputs_Product_ResEVSEDLC-Winter" peak load impact assumption. Available at: https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655868985770
Program Participation	% of eligible segment/end-use load	DLC: 25%	In line with assumptions for DLC products.
Event Participation	%	0.95	Based on 2021 Plan Workbook "Inputs_Product_ResEVSEDLC-Winter" event participation assumption. Available at: https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655868985770

Transmission & Distribution Deferral Cost Update

PSE received feedback from Kyle Frankiewich (WUTC) and Fred Heutte (NWEC) requesting more details behind the numbers on slide 13: "Updates in 2021 CPA: T&D deferral benefit." The costs that the Power Council is using in their 2021 Plan is significantly lower that the ones used in the 7th Plan[1]. The Council updated its assumptions for the 2021 Plan: no new T&D development projects were included in the update, and for T&D upgrade projects, only capacity related costs were included. In past IRPs, PSE has used the Council's T&D deferral numbers. Since the costs came down substantially in the Council's 2021 plan, PSE decided to update their own system related costs. The PSE system estimates came close to the updated Power Council estimates, these were presented on slide 13 of the July 14 Webinar.

PSE reviewed projects going back to 2010 and included projects or portions of the projects that were related to the capacity upgrades on the T&D systems. The costs for reliability projects and routine O&M were excluded as conservation will not impact these costs.

Details of the projects used to estimate the new T&D deferral costs are in Appendix A.

Fuel Conversion from Gas to Electric

PSE received feedback from Kyle Frankiewich, Willard Westre, Rob Briggs and Court Olson concerning inclusion of measures or sensitivities to test the impact of converting some end uses from gas to electricity use. PSE has added fuel conversion as a sensitivity for further discussion with stakeholders at the August 11 webinar.

Distributed Solar pV

PSE received feedback from Fred Heutte (NWEC) and Kyle Frankiewich (WUTC) that the cost curve was not up to date, and that a sensitivity should be considered with a lower cost curve. Fred referenced to the recently released (July 2020) 2020 ATB data from NREL.

[1] https://www.nwcouncil.org/sites/default/files/2019_0312_p3.pdf

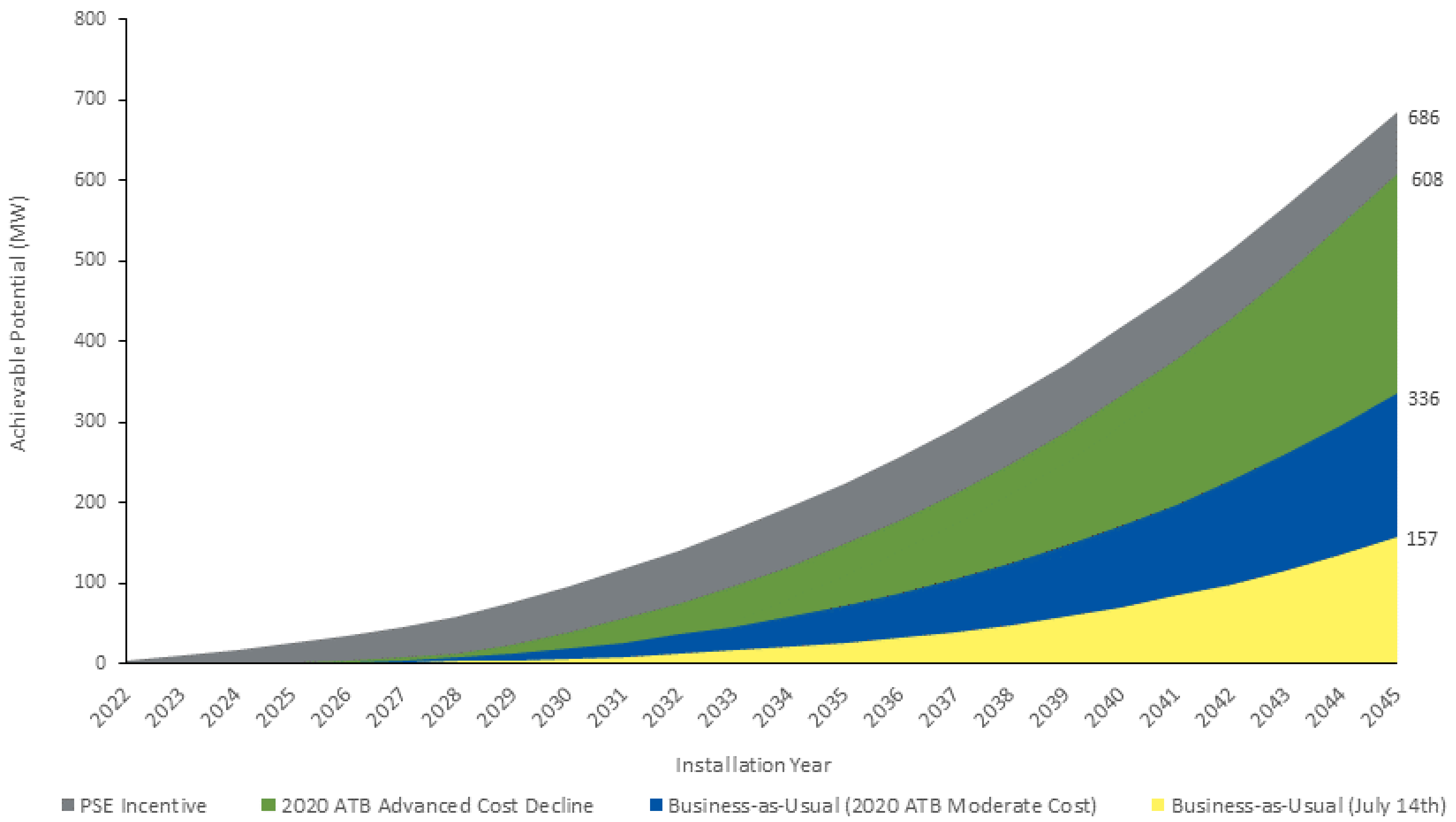
Cadmus had used the 2019 ATB data in their webinar slide, and has since updated the distributed solar pv market potential using the 2020 ATB data. As NWEC had suggested the costs are lower.

The figure below shows the results. The business as usual (BAU) case, which represents the current net metering program, updated with the 2020 MTB *Moderate* Cost forecast, now shows 24-year cumulative potential of 336 MW, which is about 10% higher than the program's straight line projection of 300 MW, which was shown in the August 14 webinar.

Furthermore, the 2020 ATB *Advanced* Cost Decline forecast shows 24-year cumulative potential of 608 MW.

Based on these results and feedback from the stakeholders, PSE will:

1. Update the business as usual (BAU) case to the 2020 ATB *Moderate* Cost forecast, and
2. Replace the PSE incentive sensitivity with the 2020 ATB *Advanced* Cost decline as the sensitivity



There was also a request for historical acheivements to date with respect to PSE's distributed solar pv program. The following is the historical data for all customer classes, including a breakdown by sector:

Total historical installations:

Year installed	Number of Systems	kW AC	kW DC
2000	1	4	1
2001	3	7	4
2002	7	15	12
2004	12	42	34
2005	8	34	30
2006	39	238	236
2007	85	438	409
2008	84	405	399
2009	157	818	814
2010	199	1,148	1,169
2011	227	1,447	1,532
2012	405	2,429	2,627
2013	572	3,913	4,123
2014	691	4,731	5,176
2015	1363	9,907	10,619
2016	1245	10,497	11,659
2017	1009	8,072	9,200
2018	1590	13,688	15,695
2019	1535	14,301	16,215
2020	**605**	**6,189**	**6,859**
Grand Total	**9837**	**78,322**	**86,813**

Installations by customer class:

Sector	Percent Share	
	Systems	kW AC
Commercial	5%	14%
Industrial	0.03%	0.17%
Residential	95%	85%

Equity in the IRP

PSE has scheduled a discussion with WUTC staff regarding an equity assessment in the IRP. Further details will be available by the end of September.

Load Forecast in the CPA

PSE received feedback from several stakeholders expressing concerns that the load forecast used to develop the CPA was a draft and what might happen if the final load forecast is considerably different. There was also a general perception that the changes in load forecast have a major impact on the conservation savings.

Changes in load forecast have a relatively minor impact on the total acehievable potential. The CPA will be updated with the final load forecast.

Demand Side Resource Sensitivities

PSE received feedback from several stakeholders to consider several sensitivities – see section below on "Summary of all updates" for details. All stakeholder suggested sensitivities have been added to the August 11 webinar for further discussion.

Summary of all updates

PSE appreciates the feedback provided by stakeholders. In summary, the following changes will be implemented:

- Workbooks requested by NWEC – PSE is working with Cadmus to provide a measure details workbook for their review. This will be provided towards the end of August.
- T&D deferral cost update details – details of the updated T&D numbers are presented in Appendix A below.
- PSE will include a discussion and provide historical data on acheivements to date for PSE's net metered distributed solar pV program in the demand side resources report.
- Electric Vehicle levelized cost for the DR program is summarized on page 1 of this report.
- Several sensitivities listed below were suggested by stakeholders. PSE will review the list of proposed portfolio sensitivities with stakeholders at the August 11, 2020 webinar and will seek feedback around the details of these sensitivities and additional sensitivities:
    - PSE will remove the PSE incentive and PSE ownership sensitivities and instead consider the one proposed by the stakeholders: sensitivity with a lower cost curve using the 2020 ATB *Advanced* scenario.
    - Accelerated DSR 6 year ramp for discretionary measures
    - Accelerated DSR 8 year ramp for discretionary measures
    - Non Energy impacts using EPA estimates
    - Social discount rate of 2.5% consistent with the social cost of carbon from the technical support document
    - Fuel conversion gas to electric
- PSE will update the CPA with the final load forecast and a discussion of the changes will be provided in the demand side report.

Appendix A: T&D Cost update details

PSE T&D Deferral Cost Summary:

PSE deferral costs	$/kW-yr	$/kW-yr 2020$
Transmission	$ 5.22	$ 5.22
Distribution	$ 7.40	$ 7.40
T&D Deferral Costs	$ 12.61	$ 12.61

Power Council deferral costs 2021 Plan	$/kW-yr 2016$	$/kW-yr 2020$
Transmission	$ 3.08	$ 3.35
Distribution	$ 6.85	$ 7.45
T&D Deferral Costs	$ 9.93	$ 10.79

Power Council deferral costs 7th Plan	$/kW-yr 2012$	$/kW-yr 2020$
Transmission	$ 26.00	$ 29.55
Distribution	$ 31.00	$ 35.23
T&D Deferral Costs	$ 57.00	$ 64.77

PSE TRANSMISSION SYSTEM PROJECTS DATA:

Project	Capital Investment 2020$	Capacity Gained (MW)	Power Factor	Discount rate	Asset lifetime	Result $/kW-yr
Alderton Substation Project Totals	$ 28,277,441	1021	0.98	6.97%	35	2.18
Sedro - Horseranch Project Totals	$ 43,651,437	1203	0.98	6.97%	35	2.85
Juanita Substation Upgrade Project Total	$ 6,969,792	25	0.98	6.97%	35	21.90
Greenwater Upgrade Project Total	$ 7,638,716	15	0.98	6.97%	35	40.00
Cumberland Substation Rebuild Project Total	$ 7,900,038	0	0.98	6.97%	35	0.00
Thorp Substation Rebuild Project Total	$ 3,545,756	0	0.98	6.97%	35	0.00
Sedro - Baker #2 Reconductor Project Total	$ 27,628,881	330	0.98	6.97%	35	6.58
Spurgeon Substation Project Total	$ 1,895,271	339	0.98	6.97%	35	0.44
Maxwelton Substation Project Total	$ 7,869,250	1046	0.98	6.97%	35	0.59
Sedro - Fredonia T-Line Uprate	$ 6,929,378	94	0.98	6.97%	35	5.79
Mt. Si Substation Project Total	$ 16,012,300	25	0.98	6.97%	35	50.31
Port Madison Substation Project Total	$ 18,206,586	252	0.98	6.97%	35	5.68
Sterling Substation Project Total	$ 30,909,684	45	0.98	6.97%	35	53.96
Spurgeon Substation Project Total	$ 32,515,004	45	0.98	6.97%	35	56.76
Blackburn Substation Project Total	$ 43,823,648	45	0.98	6.97%	35	76.50
Ardmore Substation Project Total	$ 24,951,787	261	0.98	6.97%	35	7.51
Semiahmoo Substation Project Total	$ 6,599,786	0	0.98	6.97%	35	0.00
Total/Average	$ 315,324,755	4746	0.98	6.97%	35	5.22

PSE DISTRIBUTION SYSTEM PROJECTS DATA:

Project	Capital Investment 2020$	Capacity Gained (MW)	Power Factor	Discount rate	Asset lifetime	Result $/kW-yr
New OH FDR addition	$ 1,451,190	13.96	0.98	6.97%	35	$ 8.16
New UG FDR addition	$ 938,758	9.05	0.98	6.97%	35	$ 8.15
New OH FDR addition	$ 327,970	13.96	0.98	6.97%	35	$ 1.84
New FDR WCA	$ 2,420,732	13.96	0.98	6.97%	35	$ 13.62
New UG FDR addition	$ 2,153,063	9.05	0.98	6.97%	35	$ 18.69
New UG FDR addition	$ 1,081,724	9.05	0.98	6.97%	35	$ 9.39
New UG FDR addition	$ 379,362	9.05	0.98	6.97%	35	$ 3.29
New UG FDR addition	$ 209,939	9.05	0.98	6.97%	35	$ 1.82
Repl 1-ph lateral w/OH FDR	$ 1,470,663	13.96	0.98	6.97%	35	$ 8.27
Extend UG FDR	$ 238,033	9.05	0.98	6.97%	35	$ 2.07
UG FDR tie	$ 275,575	9.05	0.98	6.97%	35	$ 2.39
UG FDR extension	$ 1,351,231	9.05	0.98	6.97%	35	$ 11.73
UG FDR extension	$ 2,185,186	9.05	0.98	6.97%	35	$ 18.97
Extend UG FDR in existing conduit	$ 282,905	9.05	0.98	6.97%	35	$ 2.46
Upgrade 3-167 auto to 7.5 MVA	$ 2,642,984	7.00	0.98	6.97%	35	$ 29.66
Extend UG FDR	$ 449,758	9.05	0.98	6.97%	35	$ 3.90
UG FDR extension	$ 760,693	9.05	0.98	6.97%	35	$ 6.60
Reconductor from #6CU to OH FDR 397.5	$ 162,528	10.57	0.98	6.97%	35	$ 1.21
New OH FDR TW Extention	$ 602,496	13.96	0.98	6.97%	35	$ 3.39
OH FDR 397.5	$ 294,938	15.20	0.98	6.97%	35	$ 1.52
OH FDR 397.5	$ 1,403,819	10.65	0.98	6.97%	35	$ 10.35
new FDR breaker &UG FDR	$ 937,867	9.05	0.98	6.97%	35	$ 8.14
Repl 3.75 MVA trf with 20 MVA	$ 70,953	16.25	0.98	6.97%	35	$ 0.34
Add two addional #2 ACSR conductors	$ 1,374,218	3.23	0.98	6.97%	35	$ 33.46
Recond 2/0 to 397.5, 5.91, added capacity	$ 1,542,684	7.92	0.98	6.97%	35	$ 15.29
Recond 2/0 to 397.5, 5.91, added capacity	$ 472,612	7.92	0.98	6.97%	35	$ 4.69
Recond 1-ph #6 CU to 336.4 TW FDR	$ 725,016	12.83	0.98	6.97%	35	$ 4.44
OH FDR 397.5	$ 1,908,196	11.24	0.98	6.97%	35	$ 13.34
Add I -ph #2 ACSR	$ 55,644	1.61	0.98	6.97%	35	$ 2.71
Recond 4/0 ASCR to 397.5 FDR	$ 736,591	5.59	0.98	6.97%	35	$ 10.36
Recond 2/0 CU to 397.5 FDR	$ 223,865	5.72	0.98	6.97%	35	$ 3.08
Recond 2/0 CU to 397.5 FDR	$ 253,699	5.72	0.98	6.97%	35	$ 3.49
OH FDR 397.5	$ 445,011	15.20	0.98	6.97%	35	$ 2.30
Recond #2 ACSR to 397.5 FDR	$ 330,543	10.44	0.98	6.97%	35	$ 2.49
Recond #4 CU to 397.5 FDR	$ 585,694	10.65	0.98	6.97%	35	$ 4.32
Recond #4 CU to 336.4 TW FDR	$ 1,282,001	9.42	0.98	6.97%	35	$ 10.69
Recond #6 CU to 397.5 FDR	$ 632,575	11.80	0.98	6.97%	35	$ 4.21
Recond #6 CU to 397.5 FDR	$ 737,312	11.80	0.98	6.97%	35	$ 4.91
Recond #2/0 CU to 397.5 FDR	$ 168,986	5.72	0.98	6.97%	35	$ 2.32
New UG FDR Extension	$ 1,190,576	9.05	0.98	6.97%	35	$ 10.33
New UG FDR Extension	$ 1,496,886	9.05	0.98	6.97%	35	$ 12.99
Recond #4 ACSR to FDR TW	$ 228,706	10.33	0.98	6.97%	35	$ 1.74
UG FDR 750	$ 4,020,530	9.05	0.98	6.97%	35	$ 34.90
UG FdDR	$ 178,224	9.05	0.98	6.97%	35	$ 1.55
UG FDR Extension	$ 384,637	9.05	0.98	6.97%	35	$ 3.34
UG FDR Extension	$ 391,211	9.05	0.98	6.97%	35	$ 3.40
New 750 UG Fdr, 1/0 UG, FDR TW	$ 3,007,573	9.05	0.98	6.97%	35	$ 26.11
Extend new 750 UG Fdr, new 1/0 UG section	$ 132,136	9.05	0.98	6.97%	35	$ 1.15
New 750 UG Fdr; new OH FDR TW	$ 442,187	9.05	0.98	6.97%	35	$ 3.84
New 750 UG Fdr	$ 2,107,015	9.05	0.98	6.97%	35	$ 18.29
new 750 UG Fdr, new 1/0 3-ph	$ 265,951	9.05	0.98	6.97%	35	$ 2.31
Recond 2/0 with 336.4 ACSR TW and 397.5 FDR	$ 290,545	7.92	0.98	6.97%	35	$ 2.88
Recond 1- ph #6 CU with 336.4 TW FDR	$ 366,913	12.83	0.98	6.97%	35	$ 2.25
Add new FDR 336.4 TW	$ 1,509,437	13.96	0.98	6.97%	35	$ 8.49
Recond 1-ph #6 CU with 397.5 FDR	$ 383,763	14.07	0.98	6.97%	35	$ 2.14
Recond 2-ph #4 ACSR with 336.4 FDR	$ 1,588,710	11.39	0.98	6.97%	35	$ 10.95
Recond 3-ph #2 ACSR to 397.5 FDR	$ 2,346,705	7.92	0.98	6.97%	35	$ 23.26
Recond 2-ph #2 ACSR to 336.4 FDR TW	$ 888,821	10.59	0.98	6.97%	35	$ 6.59
Recond 1-ph #6 CU with 336.4 TW	$ 628,079	12.83	0.98	6.97%	35	$ 3.84
Repla 2/0 CU with 397.5 FDR	$ 131,277	5.72	0.98	6.97%	35	$ 1.80
Repl 1-ph #2 ACSR with 3-ph #2 ACSR TW	$ 738,696	2.76	0.98	6.97%	35	$ 21.02
Repl 2-ph #2 ACSR with 3-ph #2ACSR TW	$ 777,704	1.15	0.98	6.97%	35	$ 53.21
New 336.4 FDR TW	$ 393,919	13.96	0.98	6.97%	35	$ 2.22
New UG 1/0	$ 355,356	3.64	0.98	6.97%	35	$ 7.68
New FDR DUV-16	$ 1,091,254	9.05	0.98	6.97%	35	$ 9.47
New UG FDR	$ 2,355,496	9.05	0.98	6.97%	35	$ 20.45
New 750 UG Fdr	$ 124,622	9.05	0.98	6.97%	35	$ 1.08
Reconductor #2 ACSR to 397.5 FDR	$ 98,862	10.35	0.98	6.97%	35	$ 0.75
new UG FDR	$ 2,068,257	9.05	0.98	6.97%	35	$ 17.95
10 new UG FDRs	$ 7,025,651	90.50	0.98	6.97%	35	$ 6.10
Totals/Average	$ 70,576,718	749.61	0.98	6.97%	35	**$ 7.40**

Webinar #5: Social Cost of Carbon Q&A

7/22/2020

Overview

On July 21, 2020 Puget Sound Energy hosted an online meeting with stakeholders to discuss the social cost of carbon. PSE informed stakeholders of the methodology used to model the social cost of carbon in the 2021 IRP analysis and the methodology used to calculate upstream natural gas emissions. Stakeholders shared their input on possible scenarios or sensitivities regarding the social cost of carbon. Additionally, participants were able to ask questions and make comments using a chat box provided by the Go2Meeting platform.

Below is a report of the questions submitted to the chat box. Answers to the questions were provided verbally by IRP staff during the webinar. Please note that questions were answered in order of relevance to the topic currently being discussed. Questions regarding other topics were answered at the end of the webinar session.

To view a recording of the webinar and to hear responses from staff, please visit the project website at pse-irp.participate.online.

Attendees

A total of 47 stakeholders and PSE staff attended the webinar, plus another seven attendees who called into the meeting and did not identify themselves (54 people total).

Attendees included: Amy Wheeless, Ashton, Bill Pascoe, Brian Grunkemeyer, Brian Robertson, Charlie Black, Cody Duncan, Dan Kirschner, Don Marsh, Doug Howell, Edward Finklea, Elyette Weinstein, Fred Heutte, James Adcock, Jane Lindley, Jennifer Mersing, Jim Loring, Joni Bosh, Kary Buri, Kathi Scanlan, Katie Ware, Kevin Jones, Kyle Frankiewich, Liz Klumpp, Devin McGreal, Michael Laurie, Michael Noreika, Mike Hopkins, Ned Whiting, R. C. Olson, Richard Sawyer, Robert Briggs, Sarah Laycock, Sophia Spencer, Stephanie Chase, Ted Drennan, Virginia Lohr, Vlad Gutman-Britten, and Willard (Bill) Westre.

Questions Received

Questions from attendees are posted in the order in which they were received. The webinar began at 1:30 PM PDT and ended at 4:29 PM PDT.

Name	Time Sent	Comment
Alison Peters	**1:35 PM**	Hello to everyone joining the webinar today. Just a couple of friendly reminders to stay muted until we stop for questions. You are also welcome to type in your name to let the group know who is here today.
ET69	**1:36 PM**	To be really safe…don't ride a bike in cities. 😉
Kyle Frankiewich	**1:39 PM**	Hello all, Kyle Frankiewich with WUTC staff here
Jane Findley	**1:42 PM**	What level of International Association for Public Participation (IAP2) engagement will be used in the meeting today? Inform, Consult, Involve or a combination? Thanks!
Penny Mabie	**1:44 PM**	Thank you for your question. As mentioned, this webinar will be at Inform and Consult on the IAP2 Spectrum.
Virginia Lohr	**1:45 PM**	What are the levels of public participation anticipated for the methane portion of the presentation? You only told us about the participation for the SCC portion of the talk. It would be helpful to have this information clearly communicated to us before a meeting.
Joni Bosh	**1:46 PM**	Question slide 11 and appendix - Why go through the elaborate conversion from metric tons to short tons?
Doug Howell	**1:47 PM**	I'm hearing an echo from Elizabeth
James Adcock	**1:47 PM**	Does one of the facilitators still have their mic on? Please *everyone* except of Elisabeth make sure your mic is muted so we can try to get rid of the echo.
Kevin Jones	**1:48 PM**	Slide 12: Will that SCC value be static over the entire analysis period or will the values "escalate" over the analysis period?
Kevin Jones	**1:50 PM**	Slide 12: - Will PSE adjust the SCC value to "then year dollars" in their analysis?
Doug Howell	**1:50 PM**	Slide 12 - applies to EE. Doesn't applying scc to dispatch model affect how it impacts energy efficiency.
James Adcock	**1:50 PM**	Jim Adcock Raise Hand Slide 14
Doug Howell	**1:50 PM**	In the real world model, there is no carbon tax. But in the real world, the are very real carbon impacts.
Charlie Black	**1:51 PM**	Disagre with characterization of including SCC at dispatch as a "tax". It is not a tax, it is an environmental externallity.

Kathi Scanlan	**1:51 PM**	Staff recommends an update and annual adjustment (from 2018 to 2019 dollars per metric ton); the Commission's website table should be updated by the end of July (for its calculation, staff uses BEA GDP Table 1.1.4 Annual Price Indexes Line 1, last revised May 28, 2020
Fred Huette	**1:51 PM**	Why is PSE using a 2.5% inflation rate? Most estimates (for example US Bureau of Economic Analysis) tend to be around 2.1%. This won't make much difference in the short run but can have an effect over 10+ years.
Joni Bosh	**1:54 PM**	Question Slide 14 - This slide says SCC is added to conservation, but where is that demonstrated in these slides? Excluding SCC from dispath modelint makes it more likely that new thrmal resources will run more; we would urge you to run the SCC as a variable cost.
Charlie Black	**1:56 PM**	There is nothing in CETA that precludes a utility from using SCC as a cost adder at time of dispatch in its IRP modeling or resource acquisition evaluation. To be clear, PSE is proposing to treat SCC as a tax, which it is not.
Irena Netik	**1:56 PM**	Response to Virginia Lohr's question: Upstream emissions which will be discussed later in this meeting is inform on the IAP2 spectrum. Thank you.
Charlie Black	**1:58 PM**	I suggest that PSE review the concept of environmental externmalities and how they are properly used to reflect costs that are not priced in the marketplace.
James Adcock	**2:00 PM**	Slide 14 -- If the resource decision has already been made, then for what reason are you running a subsequent resource dispatch model?
Michael Laurie	**2:01 PM**	To follow on Doug's question about slide 13. I see that SCC plays a role in deciding to select conservation at the front end but we all know that how things play out from year to year will always vary from the the expectations in planning and IRP efforts. So when there is a greater demand for energy than planned for and if that demand exceeds what conservation and renewables were assumed to be sufficient it appears that you would be in a situation where you will be making energy resource decisions that no longer include SCC.
Kyle Frankiewich	**2:04 PM**	Slide 14: To echo Joni's question, I'm not tracking on how the fixed-cost approach to SCC impacts the portfolio optimization. Does the model 'know' that dispatching a gas plant is adding more costs to the total portfolio than are shown in dispatch? Happy to wait til later slides
Kyle Frankiewich	**2:06 PM**	I understood Elizabeth's use of the word 'tax' as specifying how it would be added to the dispatch model.
Doug Howell	**2:07 PM**	+++ to Charlie Black's statement

James Adcock	**2:09 PM**	Re Charlie's concerrns -- IRPs are a "public process" and I would like to see Charlie's concerns in this area (as long as everyone else's) discussed, in a discussion, in a public IRP forum.
Kevin Jones	**2:10 PM**	- Slide 17: Lowest REASONABLE cost
Kevin Jones	**2:11 PM**	Slide 18: Step 1: How does PSE determine the dispatch plan for thermal plants? What is the dispatch schedule for other PSE assets? What is the capacity factor used for wind and solar during this part of the analysis? Slide 18: Step 4: What is determined when you “re-run the portfolio model”? Slide 18: How is SCC applied to fuel sources, including upstream methane leaks?
Joni Bosh	**2:12 PM**	+++to kevin's clarification that is lowest REASONABLE cost
Bill Westre	**2:15 PM**	S-19 What is the source of Tons CO2 - MW? Dispatch %?
Kyle Frankiewich	**2:16 PM**	I'm understanding the figures in slide 20 as an illustrative example of how SCC out of dispatch lets thermal plants run more, which in turn runs up their total cost relative to alternatives.
Charlie Black	**2:16 PM**	Does this aproach for treating SCC as a "tax" assume that the SCC is a dollar cost that flows through to PSE ratepayers? If so, that is not a proper way to apply SCC as an environmental externality.
Doug Howell	**2:20 PM**	Slide 20. How will this affect operations and dispatch of peaker plants?
Katie Ware	**2:17 PM**	Slide 20: The numbers in the table appear to be round estimates to illustrate the initial principle that SCC-as-adder will result in higher carbon-related costs for a resource, without going into that final round of optimization. Does PSE think the CF difference would be as extreme as 30% v 70%, or did PSE pick a relatively extreme example to help illustrate the idea?
Joni Bosh	**2:20 PM**	Slide 20 - all else being equal, the SCC as a cost adder increases capacity, which would lead to LCOE going down. Even if LCOE is not the only factor considered, doesn't this lead to dispatch picking the less costly thermal plant more and more frequently in Aurora?
Charlie Black	**2:21 PM**	In actuality, since the SCC is an environmental externality that is not explicitly priced in the wholesale power market, it is not a dollar cost that would affect PSE's revenue requirements or its retail electric rates under EITHER approach to incorporating SCC. So this calls into question the validity of PSE's analytical approach, including treating SCC as a fixed cost adder OR as a "tax".

James Adcock	**2:22 PM**	Did Puget ever figure out whether their "80 Year Hydro" include the BPA "fixes" related to the change of BPA dispatch protocols back in the 80s -- i.e. has older Hydro data been corrected to account for current dispatch protocols?
Charlie Black	**2:23 PM**	However, since the environmental damages caused by GHG emissions are real (albeit unpriced) costs, they should be included in ecnomic dispatching decisions. Another way to say this is that economic dispatch decisions should include all real costs, including both priced and unpriced costs.
Fred Huette	**2:26 PM**	referring to my previous comment about inflation rate, the NW Council is currently using an average rate of about 2.095% for 2021-40 -- see https://nwcouncil.app.box.com/v/StandardInfoWorkbookv4-2
Kyle Frankiewich	**2:27 PM**	I'm confused about how this wouldn't change the dispatch. Presumably each iteration will prompt AURORA to select a different proxy resource, which will change the dispatch and cause thermals to run differently from the first iteration of the determinative run.
Kevin Jones	**2:28 PM**	Regarding inflation rate - is this a PSE decision or is this a UTC decision that is incorporated into the SCC "costs" they publish on their website?
Kyle Frankiewich	**2:29 PM**	Does the 2nd iteration then take the plant, fully laden with SCC as a fixed cost, and set its dispatch as modeled in the 1st iteration (which would be something other than optimized)?
James Adcock	**2:29 PM**	I know that PSE doesn't want to include SCC in their modeling of dispatch, but doesn't CETA require in the "must" expression that utlities, including PSE, "must" include SCC in all aspects of modeling for IRP development?
Bill Westre	**2:29 PM**	S-19 What causes the drop in Tons CO2 in 2025
Vlad Gutman-Britten	**2:30 PM**	Dispatch is based on marginal cost, not LCOE.
Vlad Gutman-Britten	**2:33 PM**	How does SCC impact amount of conservation selected? Is EE selected as part of the Aurora portfolio runs?
James Adcock	**2:36 PM**	How does your modeling model the problem of "once in 20 years extended winter drought" in the decision to (possible) retire existing combined cycle plants?
Charlie Black	**2:37 PM**	I have a question about the format for these feedback sessions. Is the primary form of "feedback" supposed to just be clarifying questions? Is less opportunity being provided for stakeholders to provide comments and suggestions?

Joni Bosh	**2:37 PM**	Question slide 21 - In the oval, what is the basis of the "cost adder"? also, the content of the green circle changed a bit since it was presented in december - does that mean some of the data input to the model has changed as well?
James Adcock	**2:38 PM**	Slide 22 -- for what purposes does PSE use the "Final portfolio dispatch & cost" ?
Michael Laurie	**2:41 PM**	In comparing conservation to other resources is the loss of revenue from conservation included or ignored?
Joni Bosh	**2:41 PM**	Where is the SCC value of the DSR added?
Charlie Black	**2:47 PM**	Thanks for your ressponse. I hope we can put that approach into practice.
Joni Bosh	**2:48 PM**	To clarify previous question, I understand your explanation of comparing costs of demand and supply side resources, but I am still not clear how the value of SCC is applied to say an individual efficiency measure.
Vlad Gutman-Britten	**2:49 PM**	But SCC creates a relative benefit for EE as a result.
James Adcock	**2:55 PM**	How about a Scenario of: West-Coast CO2 tax -- WA, OR, CA ?
Kevin Jones	**2:55 PM**	Slide 23: What does your statement about upstream emissions mean?
Katie Ware	**2:58 PM**	Slide 23 suggests upstream emissions will not be included in the base, but (jumping forward) slides 29 et seq suggest PSE will include upstream emissions. Could you please clarify?
Joni Bosh	**3:01 PM**	We would like to see a scenario that applies the SCC to the variable costs to allow comparisons of the two approaches.
Doug Howell	**3:02 PM**	+++ on a dispatch scenario
Kevin Jones	**3:02 PM**	+++ Joni's suggestion for scenarios looking at application of SCC to dispatch
Kyle Frankiewich	**3:08 PM**	keith's connection is not as good as it could be
Fred Huette	**3:10 PM**	AR4 is out of date and AR5 should be used, among other things it predates the Paris Agreement. The methane emissions factors were significantly refined in AR5.
Doug Howell	**3:10 PM**	Slide 30. Have you addressed the complaints raised by the Stockholm Environment Institute about the GREET and GHGenius models?

Robert Briggs	**3:12 PM**	Slide #30 - Upstream gas emission rate data sources Excuse me if I missed it, but would you please tell us the rates of upstream life-cycle methane leakage that are being assumed as a percentage of methane delivered for both power generation and direct customer use?
Fred Huette	**3:13 PM**	I will have a comment on the PSCAA and Canadian metrics used in the GHGenius model.
Doug Howell	**3:13 PM**	Slide 32. How can you focus on gas supply from Canada? This avoids the fundamental climate principle of "leakage"
Don Marsh	**3:13 PM**	+++ Robert's question. I'm also interested in the methane leakage rate.
Kevin Jones	**3:14 PM**	Slide 30: Could you provide your rationale for PSE plans to use the 100 vs 20-year GWP for the CO2 equivalent of various GHG's
Doug Howell	**3:14 PM**	Slide 34. What is the total percentage of leakage from wellhead to end use?
Doug Howell	**3:15 PM**	Hand raised
Kevin Jones	**3:15 PM**	Slide 35: Will PSE consider a sensitivity that varies the source of gas (instead of just assuming that all new gas will come from BC)?
Fred Huette	**3:16 PM**	I will be summarizing a comment NWEC submitted to the NW Council (the doc also includes staff presentation on upstream methane and NWGA letter): https://www.nwcouncil.org/sites/default/files/2020_0616_2.pdf
Robert Briggs	**3:19 PM**	Keith did not answer my question.
Vlad Gutman-Britten	**3:20 PM**	Slide 34 I believe is on a CO2 basis, not on a volume basis. Can you please clarify that and provide it on a volume basis?
Robert Briggs	**3:22 PM**	Slide #34 The GREET model includes data from a robust up-to-date meta-study of methane leakage in the US that found methane leakage rates more than twice as high as those you show on slide #34. Those results were summarized in a 2018 paper by Alverez et al. in Science. Do you intend to use those data in the 2021 IRP? If not, why not?
Kevin Jones	**3:23 PM**	Please reply to Fred's comments.

Robert Briggs	**3:23 PM**	Please explain your justification for using the 100-year GWP value for methane for methane when the IRP study period is limited to 20 years for all other costs and the UN has declared we have just ten years to make major reductions in greenhouse gas emission before causing irreversible damage. AR4 values are out of date. AR5 provides values reflecting current science Please explain you justification using these obviously flawed values in this forward-looking IRP process.
Jane Lindley	**3:23 PM**	+++ Fred Huette's comment outmoded data - it's critical to have current science/numbers to measure upstream emissions.
Robert Briggs	**3:25 PM**	Slide #30 - Upstream gas emission rate data sources In the gas section of the 2017 IRP, PSE stated that the percentage of methane leaked by PSE (as distinct from upstream emissions) was 0.5%. a) Is the assumption 0.5% methane leakage on PSE's watch also being assumed for the 2021 IRP? b) Is that leakage included in the values shown for upstream methane emissions? c) What is the basis for the in-house leakage assumptions? d) Is methane leakage by your end-use gas customers included in PSE's greenhouse gas emissions or are they ignored?
Doug Howell	**3:27 PM**	AR4 is old data. You can go better than that.
Doug Howell	**3:28 PM**	+++ Yes, do a sensitivity using AR5
Don Marsh	**3:29 PM**	Ouch. PSE asked for consultation on sensitivities. A reasonable suggestion was just rejected. Disappointed.
ET69	**3:30 PM**	Agreed!
Kyle Frankiewich	**3:31 PM**	raised hand
Dan Kirschner	**3:34 PM**	I will point out that the most recent (2020) EPA emissions rate estimate is 1.0%, not 1.4% as suggested by Mr. Gutman Britten. 1.4% was from the 2018 EPA Inventory.
Fred Huette	**3:34 PM**	See slide 12 of the NW Council staff presentation for a comparison of estimated upstream methane emission rates. Among them: EDF median 2.84%, EPA median 1.82%.
Dan Kirschner	**3:36 PM**	The EPA median rate offered by Mr. Huette is from the 2018 invnetory and includes both oil and gas systems. The current inventory (2020) estimates 1.0% methane emissions from natural gas systems.

Robert Briggs	**3:40 PM**	I have attempted to look at the assumptions in GHGenius v4.0a (2016). The documentation is not available. Can you help me gain access to the documentation for this version of the progam that has been supplanted? The issue is important because without it we can not tell whether recent research with much higher leakage rates have been included.
Virginia Lohr	**3:47 PM**	I thought the law said something like "least REASONABLE cost" as what you are to pursue for customers, not just least cost or lowest cost. Is this true? If so, why do you consistently drop the word "reasonable"? This was raised this repeatedly during the last IRP, yet your language didn't seem to change. It's hard to trust you on the important things we can't see, such as what you are actually putting in your models, when we are constantly frustrated by these simple obvious things we can see and have brought up so often, including Kevin Jones' comment earlier in the chat.
Robert Briggs	**3:48 PM**	Question for Elizabeth, can you explain one more time what questions are answered by the final portfolio dispatch and cost runs?
Don Marsh	**3:51 PM**	Where does the CETA 2% annual cost premium get factored in? In other words, if a low-emission solution is within 2% of the cost of a higher-emission solution, doesn't CETA mandate the lower emission solution? Or perhaps I don't understand CETA?
Kevin Jones	**3:52 PM**	One of the objectives of this meeting was to solicit scenario suggestions from the public. Several have been suggested. Could you summarize the suggestions you will consider and pose an open question to others on the call to provide their thoughts?
Robert Briggs	**3:52 PM**	Another question for Elizabeth: Is SCC not used in the dispatch runs because there is a computational problems in doing so or because you don't belive it belongs there? I'm very sceptical of analyses that treat costs that need to be analyzed at the margin as fixed costs.
Kyle Frankiewich	**3:59 PM**	I've heard the company say that they will be running SCC in dispatch as a sensitivity, followed by some participants asking for such an analysis. Can the company clarify that this will be done as a sensitivity, at least, so participants can understand the impacts of this modeling decision? Ah, i think Elizabeth said it again.
Kyle Frankiewich	**4:01 PM**	Q about retirements - hand raised
James Adcock	**4:02 PM**	Raise Hand.
Charlie Black	**4:02 PM**	PSE has said a number of times that it thinks it is not appropriate to include SCC in dispatch under CETA. Can PSE please provide a written rationale explaining the basis for its position on this, including citing relevant sections of CETA that support its position?
Kyle Frankiewich	**4:07 PM**	it would be reflected in a higher overall portfolio cost as well, yes?

Kevin Jones	**4:11 PM**	raise hand
Joni Bosh	**4:12 PM**	my connection has gone scratchy - would you write up the explanation that Kyle and Elizabeth just discussed, as I could not hear it. Thanks
Fred Huette	**4:12 PM**	We will submit the SEI comments in a meeting comment.
Virginia Lohr	**4:14 PM**	Is it prudent to go with the values of the Agency when so many questions have been raised. Wouldn't the prudent thing to do to be to follow up with what was raised? Pugent Soung Clean Air Agency
ET69	**4:16 PM**	What is PSE’s biggest concern relative to this process?
Joni Bosh	**4:21 PM**	Please identify yourself
Joni Bosh	**4:22 PM**	Thank you
Kyle Frankiewich	**4:25 PM**	I'd encourage participants to make use of the feedback forms, and would encourage the company to make sure to offer an explanation when the company decides not to adopt a suggestion.

PSE IRP Feedback Report
Webinar 5: Social Cost of Carbon
July 21, 2020

8/04/2020

The following stakeholder input was gathered through the online Feedback Form, from July 14 through July 28, 2020. PSE's response to the feedback can be found in the far-right column. To understand how PSE incorporated this feedback into the 2021 IRP, read the Consultation Update, which will be released on August 11, 2020.

Feedback Form Date	Stakeholder	Comment	PSE Response
7/16/2020	Elaine Armstrong, Citizens Climate Lobby	What is PSE doing, in good faith and at all speed, to reduce their green house gas emissions, reduce reliance on fossil fuels and create a 100% green and reusable energy sources? What you are doing now is increasing reliance on natural gas. There should be no more new plants that use fossil fuels. You need to create ways to use solar, wind, geothermal etc. Entire nations are able to do this. Surely PSE can.	PSE is modeling 80% renewable resources by 2030 and 100% by 2045 to meet the Washington Clean Energy Transformation Act (CETA). PSE is also modeling portfolio sensitivities around different clean energy futures which will be discussed at the August 11, 2020 webinar on scenarios and sensitivities.
7/16/2020	Elaine Armstrong, Citizens Climate Lobby	Build no new fossil fuel plants. Create clean energy sources with the eye to be entirely green house gas emission-free by 2040. Do more to support homeowners to overcome the giant cost of installing solar on their homes.	Thank you for your comment, thoughts and suggestions.
7/20/2020	James Adcock	Page 14 of 2021 IRP Webinar #5: Social Cost of Carbon Planning Assumptions & Resource Alternatives Electric Portfolio Model Using the Social Cost of Carbon, According to CETA I would like to have time allowed for a robust discussion of Puget's four positions expressed on this page, because they are interpretations of CETA that I, and I believe many other people, would disagree with. For example, I believe "cost adder" means logically an added cost proportional to the actual fuel being consumed, not a fixed cost that is somehow decoupled from the amount of fuel actually being used. For example, an NG plant actually dedicated to rare "reliability" concerns, such as "once in 20 years winter drought" should have very low emissions, and therefor should have very low SCC costs. Please allow robust time for discussion and possible disagreement, allowing stakeholders to fully understand, agree, or disagree, with PSE's four stated positions on this page, representing PSE's interpretation of CETA SCC "cost adder" requirements. CETA Quote: An electric utility must incorporate the social cost of greenhouse gas emissions as a cost adder when: (ii) Developing integrated resource plans and clean energy action plans; End-quote. Must" means "must" -- it does not mean that a utility can pick and choose when to turn on or to turn off SCC in their modeling.	Thank you for your comment. PSE will run several sensitivities and scenarios, requested by stakeholders, around the different ways to model the social cost of carbon. Further discussion will occur at the August 11 stakeholder meeting.
7/20/2020	James Adcock	Page 43 of 2021 IRP Webinar #5: Social Cost of Carbon Planning Assumptions & Resource Alternatives Electric Portfolio Model Please explain why PSE needs to: "In order to input the SCC into AURORA models, PSE converts the final SCC numbers into 2012$/short ton."	AURORA uses US tons (short tons) instead of metric tons. PSE converts from metric tons to short tons for the model.
7/21/2020	James Adcock	Given that PSE keeps complaining that they run out of time before answering all of the questions, could we "waste" less time on the PSE "Safety Issues" -- which have nothing to do with IRPs in any case.	Thank you for your comment.
7/22/2020	Vladimir Gutman,	Please see attached memo.	Thank you for your comments and questions. PSE responses by referenced numbers in the memo:

Feedback Form Date	Stakeholder	Comment	PSE Response
	Climate Solutions		1. PSE will work on creating a write-up of the AURORA portfolio model to include in the 2021 IRP. 2. PSE will run several sensitivities and scenarios, requested by stakeholders, around the different ways to model the social cost of carbon. Further discussion will occur at the August 11 stakeholder meeting.
7/22/2020	Kevin Jones, Vashon Climate Action Group	During the July 21 PSE IRP meeting I posted this question: Could you provide your rationale for PSE plans to use the 100 vs 20-year GWP for the CO2 equivalent of various GHG's. To which you replied that using the 100-year GWP allows you to remain consistent with your regulatory reporting requirements. When I asked would you consider this as a sensitivity, you answered "no". The Governor's Directive 19-18 requires consideration of both the 100 and 20-year GWP, saying in part: I hereby direct the Department of Ecology to adopt rules by September 1, 2021, to strengthen and standardize the consideration of climate change risks, vulnerability, and impacts in environmental assessments for major projects with significant environmental impacts. Such rules should be based on the most current climate change science, consistent with the findings of recent international and national assessments and the Department's recommendations under RCW 70.235.040. The rules should be uniform and apply to all branches of government, including state agencies, political subdivisions, public and municipal corporations and counties. The rules should cover major industrial projects and major fossil fuel projects; and establish uniform methods, processes, procedures, protocols or criteria that ensure a comprehensive assessment and quantification of direct and indirect greenhouse gas emissions resulting from the project. Rules for cumulative environmental assessments and reporting should include: • 20-year and 100-year global warming potentials for all greenhouse gases attributable to the project, as provided by the most recent international assessment Given the Governor's Directive, will you reconsider your position and include GWP variation as a sensitivity in the 2021 IRP? If not, please provide rationale.	See Final Supplemental Environmental Impact Statement of the Proposed Tacoma Liquefied Natural Gas Project, pages 4-5 and Appendix B pages 5-7, 91-93. See PSE letter to PSCAA dated November 21, 2018, pages 22-25.
7/26/2020	Virginia Lohr, Vashon Climate Action Group	Please see attached file.	Thank you for your comments. Concerning PSE's decision to present upstream emission as an "inform" level of public participation per IAP2, this is the appropriate level for an input to the 2021 IRP.
7/27/2020	Rob Briggs, Vashon Climate Action Group	Methane Releases by PSE I asked during the webinar if the values PSE is using from the GHGenius and GREET models for methane leakage rates include leakage that occurs while the gas is in PSE's custody and downstream while the gas is the custody of PSE's customers. Keith Faretra's response was "yes they do." Would you please verify formally and on the record that Keith's response is correct and that PSE stands behind that answer.	Yes, PSE stands behind that answer. PSE is using the GHGenius and GREET models to define upstream, midstream and downstream emission rates. This includes fugitive methane that occurs while the gas is in PSE's custody prior to delivery to a metered customer. Emissions from all the defined segments of the natural gas supply chain are included in the IRP analysis. The emission rates are itemized in the summary table on slide 34. Upstream of PSE's control includes extraction, processing, and transportation. Midstream is represented by the distribution segment. This is gas delivered to customers under PSE's control. Downstream emissions are those emissions associated with the end-use combustion of natural gas by PSE customers. The end use combustion rate is defined by EPA and is equal to 54,400 gCO2/MMBtu.
7/27/2020	Rob Briggs, Vashon	Slide #32 – GHGenius upstream emission rate The slide indicates that you are using GHGenius V4.0a (2016).	Thank you for your comments.

Feedback Form Date	Stakeholder	Comment	PSE Response
	Climate Action Group	When I go to the Natural Resources Canada web site and follow the GHGenius link, I find that V4.0a (2016) is not available. In September 2019 when I did a similar search to obtain GHGenius V4.0a program documentation to answer questions I had about the data sources that it uses, my effort was thwarted by this message: "The Government of Canada and S&T Squared no longer have an agreement to distribute the older versions of the model. If you need an old version please e-mail us and we can direct you to who to ask within the Government of Canada." I noted this problem in a letter sent to Irena Netik dated September 18, 2019. I am seeking the program documentation for GHGenius V4.0a (2016), so that I can examine the research documents that were used as the basis for that version of the program. During the webinar, Keith Faretra offered to provide me documentation for GHGenius V4.0a. I would appreciate being sent the GHGenius V4.0a documentation using the email address that you have on file for me. However, I am concerned that the documentation that Keith has available is not the documentation I need to answer critical questions about the underlying assumptions in the program. I do not believe it is appropriate for PSE to be using data from a program for which full documentation is not available. If the IRP process is to effectively protect the public interest, it must be open and transparent. That is particularly true for assumptions like upstream methane leakage with large and far-reaching impacts on IRP results. Research published after the 2016 that was conducted using new and more accurate measurement technologies found significantly higher levels of methane releases than those previously assumed.[1] As it currently stands, we are presented with a black box containing old data with very large impacts on IRP results and are told to simply accept its output. This is not acceptable in the context of the IRP process, in which public review is legally mandated. David Suzuki Foundation, New science reveals climate pollution from B.C.'s oil and gas industry is more than double what government claims, April 26, 2017, https://davidsuzuki.org/press/new-science-reveals-climate-pollution-b-c-s-oil-gas-industry-double-government-claims/. Make available the requested documentation or Update IRP data sources to those that are current and supported.	
7/27/2020	Rob Briggs, Vashon Climate Action Group	Slide #30 and 34 – GREET upper sensitivity rate The GREET model contains multiple data sources with a range of methane leakage rates. The value shown on slide #34 as "Upper Sensitivity" does not reflect the higher end of the values contained in GREET. In fact, the most recent and most robust methane leakage research in GREET shows a leakage rate more than twice as high as that buried in the 12,121.1 g/MMBtu displayed on slide #34. If you go to the GREET web site at Argonne National Laboratory, and look at the GREET Manual entitled Updated Natural Gas Pathways in the GREET1_2018, you encounter this: "...we added the option to use emissions data from Alvarez et al. (2018) for GREET1_2018. The data from Alvarez et al. (2018) is referred to as EDF 2018 in GREET." [1] If you have any doubt about the quality of this research, consider this passage from the GREET manual: "From 2013 to 2018, a collaboration of the Environmental Defense Fund (EDF), universities, research institutions, and companies have completed 16 projects to collect data on methane emissions from the natural gas supply chain (EDF 2018). The EPA has incorporated data from these efforts, (e.g. updated emission factors for production, processing, transmission and distribution equipment) to improve its GHGI (Burnham et al. 2015). In 2018, EDF and many of its collaborators published an analysis synthesizing data collected across the 16 projects (Alvarez et al. 2018). The researchers, similar to Brandt et al. (2014) but with updated data, used a bottom-up analysis supplemented by a top-down analysis (covering 30% of U.S. gas production) to estimate national CH_4 emissions from natural gas and oil supply chains. Their facility-based estimate of 2015 NG and oil supply chain emissions is ~60% higher than the U.S. EPA GHGI estimate. Alvarez et al. (2018) facility-based methodology uses downwind measurements which, unlike solely relying on component-based calculations as done in the GHGI, can capture emissions released during abnormal operating conditions." [2]	Thank you for your comments.

Feedback Form Date	Stakeholder	Comment	PSE Response
		It appears that PSE has within the trusted GREET data source, ready access to improved, up-to-date data on upstream fugitive emissions rates but has chosen not to use them. Please tell me why PSE has chosen to use a value for methane leakage of approximately 1% of methane delivered as an upper sensitivity when the source for that data contains highly credible research showing a 2.3% rate as the national average. During the 2019 IRP process, we were told PSE was using these same suspect values because PSE was new at accounting for upstream emissions and that we should not expect PSE to get it right the first time. That line of argument no longer works. Please consider using the leakage values in GREET labeled "EDF 2018" in a sensitivity analysis. Andrew Burnham, Updated Natural Gas Pathways in the GREET1_2018, October 2018, p. 2, pdf available here: Modelhttps://greet.es.anl.gov/publication-update_ng_2018. Ibid. Please consider using the leakage values in GREET labeled "EDF 2018" in a sensitivity analysis.	
7/27/2020	Rob Briggs, Vashon Climate Action Group	Slide #30 - Upstream gas emission assumptions The Puget Sound Clean Air Agency's report has been widely discredited, so it is disappointing to see PSE using it here as though it is capable of serving as a primary reference. It is highly counterproductive for PSE to be using data from 2007 (AR-4) when more up-to-date data from 2014 (AR-5) are available. Similarly, citing justification from the Kyoto Protocol adopted in 1997, while ignoring the UN IPCC Special Report [https://www.ipcc.ch/sr15/], released in October 2018, makes it clear that PSE does not intend to base the IRP on sound, up-to-date science. The IPCC Special Report Global Warming of 1.5 ºC stated we have (now) just ten years to make massive and unprecedented changes to global energy infrastructure to limit global warming to moderate levels. "There is no documented historic precedent" for the action needed at this moment, the report says. In this context, it is wildly inappropriate to be using a GWP 100-year value for methane for an IRP with a 20-year analysis period, in a state that has legislatively mandated rapid decarbonization of its electric utilities, and in a global environment in which approaching two thousand governments in 30 countries have declared climate emergencies over the past two years. GWP 100-year values dramatically understate the importance of near-term climate forcing from methane by averaging those impacts into the next century. It is reckless and irresponsible to continue to use GWP100 for methane. The magnitude of the errors that PSE is designing into the IRP from these upstream emission rate inputs is quite large. I and others have shown that using the low values PSE proposes leads to errors in levelized cost that are larger than the $3.56/MMBtu that PSE has been assuming as its cost of gas once those emissions are fully burdened using social cost carbon. [1] Errors of this magnitude rob the IRP analyses of any analytical value. Failure to correct the problems with these data inputs will ensure that PSE 2021 IRP is obsolete before it has even been completed. It is doubly disturbing that PSE refuses to discuss alternatives to using these erroneous values, even in sensitivity analyses. Sensitivity analyses are used to assess the impact of assumptions on which there is uncertainty. Given that these errors are both egregious and willful, the UTC would be justified in rejecting PSE 2021 IRP on the basis of these errors alone. September 19, 2019 TAG #8, Slide 15. Use the 20-year GWP for methane at the very least in a sensitivity analysis.	Thank you for your comment. See Final Supplemental Environmental Impact Statement of the Proposed Tacoma Liquefied Natural Gas Project, pages 4-5 and Appendix B pages 5-7, 91-93. See PSE letter to PSCAA dated November 21, 2018, pages 22-25.

Feedback Form Date	Stakeholder	Comment	PSE Response
7/27/2020	Virginia Lohr, Vashon Climate Action Group	PSE plans to use the upstream greenhouse emissions analysis method from the Proposed Tacoma Liquefied Natural Gas Project Final Supplemental Environmental Impact Statement prepared by Ecology and Environment, Inc. for the Puget Sound Clean Air Agency (PSCAA). This analysis is found in Appendix B: PSE Tacoma LNG Project GHG Analysis Final Report and was conducted by Life Cycle Associates. My understanding is that PSE currently proposes to consider no alternatives to this method. Is it prudent to rely solely on a consultant's report with a prominent disclaimer with the following statement? "No warranty or representation, express or implied, is made with respect to the accuracy, completeness, and/or usefulness of information contained in this report." TAG members and stakeholders raised questions about PSE's proposed use of these methods for calculating upstream greenhouse gas emissions during the 2019 PSE IRP process. Questions were again raised in the 2021 IRP webinar on this topic. One concern with the method PSCAA and PSE have adopted is its use of out-of-date science, such as the IPCC's 4th annual assessment (AR4) from 2007. Much newer science is available, including the IPCC's 5th Assessment Report from 2014 and research showing that methane is much more damaging than previously thought. While some agencies still use AR4, does that mean that PSE must also use this out-dated science? If PSE must use AR4 or choses to use out-dated science, is there any reason why PSE could not add a sensitivity based on more current science, such as AR5? Governor Inslee published Directive 19-18 on December 19, 2019. It requires the Department of Ecology to develop rules regarding greenhouse gas emissions based on "the most current climate change science," and to adopt the new rules by September 1, 2021. While the final rules will not be available for PSE to use in 2020, the fact that AR4 will no longer be acceptable in 2021 is clear. Is it prudent to refuse to use current science in the 2021 IRP, at least as a sensitivity, in light of this Directive? PSE should abandon their sole reliance on the PSCAA methods. At the very least, PSE should add a sensitivity that uses current science and addresses concerns raised in the 2019 and 2021 IRP processes, including using global warming potential values for methane from AR5 and adding a sensitivity analysis using the 20-year global warming potential for methane, which the Governor's Directive specifically mentions should be part of the new rules. Getting these calculations correct is critical to getting the right answer on what is reasonable, wise, and prudent for PSE to do for their investors, for rate-payers, for people living near their polluting facilities, and for the future of humanity.	See Final Supplemental Environmental Impact Statement of the Proposed Tacoma Liquefied Natural Gas Project, pages 4-5 and Appendix B pages 5-7, 91-93. See PSE letter to PSCAA dated November 21, 2018, pages 22-25.
7/28/2020	Rob Briggs, Vashon Climate Action Group	Slide #14 - Using the Social Cost of Carbon, According to CETA 'PSE understands this "cost adder" to mean that the SCC is included in resource planning decisions as a part of the Fixed O&M costs of that resource.' The social costs of greenhouse gas emissions are a function of the quantity emitted. Therefore, the social cost of carbon must be treated as a variable cost in portfolio optimizations. Treating SCC as a fixed cost dramatically lowers the apparent marginal cost of fossil-fuel use and represents an implicit subsidy for fossil-fuel use in the planning model. Please explain clearly why PSE proposes to include SCC as part of the fixed costs when it properly should be treated as a variable cost. If PSE contends that their approach grows out of specific language in CETA, please cite that specific language.	Thank you for your comment. PSE will run several sensitivities and scenarios, requested by stakeholders, around the different ways to model the social cost of carbon. Further discussion will occur at the August 11 stakeholder meeting.
7/28/2020	Rob Briggs, Vashon Climate Action Group	Treat SCC as a variable cost. Abandon all use of it as a fixed cost, which it is not.	Thank you for your comment. PSE will run several sensitivities and scenarios, requested by stakeholders, around the different ways to model the social cost of carbon. Further discussion will occur at the August 11 stakeholder meeting.

Feedback Form Date	Stakeholder	Comment	PSE Response
7/28/2020	Rob Briggs, Vashon Climate Action Group	Slide #14 – Including SCC in dispatch costs 'The SCC is not included in resource dispatch costs.' My understanding is that CETA's scope covers planning and acquisition decisions by utilities but not their operations. It remains unclear to many of us stakeholders why PSE intends to include the costs of greenhouse gas emissions in some phases of the planning process but not in others. Failure to include significant cost factors in any phase of the IRP analysis process would lead to distorted results. a) Please explain PSE's rationale for omitting this very large cost component from the dispatch modeling, if that is in fact what is being proposed. b) If this remains an unresolved issue with stakeholders, I recommend PSE run the IRP analyses with SCC consistently included throughout IRP analyses and again as a sensitivity as PSE proposes. c) If the problem PSE has with consistently including SCC in the IRP relates to discordance with real-world dispatch decisions, would not the best solution be for PSE to include SCC in their actual real-world dispatch decisions as well? Doing so would be consistent with the intent of CETA and with its long-term mandatory decarbonization benchmarks.	Thank you for your comment. PSE will run several sensitivities and scenarios, requested by stakeholders, around the different ways to model the social cost of carbon. Further discussion will occur at the August 11 stakeholder meeting.
7/28/2020	Orijit Ghoshal, Invenergy	Please see attached	Thank you for your comments. PSE has reached out to you and Charlie Black to follow-up with you and will report progress in the Consultation Update.
7/28/2020	Orijit Ghoshal, Invenergy	Invenergy encourages PSE to recognize that GHG emissions produced by its electric generating resources are environmental externalities and to treat them as such in the portfolio modeling analyses for the 2021 IRP. Invenergy encourages PSE to include the SCC in the variable dispatching costs of its GHG-emitting resources when modeling its resource portfolio for the 2021 IRP. As part of PSE's resource portfolio modeling, Invenergy encourages PSE to track and report environmental externality costs (i.e., quantities of GHG emissions multiplied by the SCC of its resources' GHG emissions), and to separately track and report the resource portfolio costs that actually go into its revenue requirements. Decisions about PSE's portfolio resource mix should be made on the basis of the sum of revenue requirements plus GHG externality costs. This will be a more realistic method for applying the SCC than either of PSE's proposed approaches. Reporting both of types of costs will also make PSE's analysis more transparent.	Thank you for your comment. PSE will run several sensitivities and scenarios, requested by stakeholders, around the different ways to model the social cost of carbon. Further discussion will occur at the August 11 stakeholder meeting.
7/28/2020	Doug Howell, Sierra Club	We should be assuming that there will not be an increase in overall gas use over the next 10 years. And there is no gas production in Washington. All gas comes from out of state or Canada. PSE asserts that all their gas comes from Canada. If so, they are pushing other buyers to other suppliers such as the Rocky Mountain states. Methane emissions from Canada have the same climate impact as methane emissions from the Rockies. As a result, PSE needs to analyze the total regional supply chain of gas that comes into Washington to fully account for upstream methane emissions. We request that PSE run a scenario (or at least a sensitivity) assessing the regional impacts of upstream methane from all gas fuel supplies into Washington. If PSE does not agree with running this scenario, then they have to explain how their gas supply is affecting the overall supply chain of gas into Washington.	Thank you for your comment.
7/28/2020	Doug Howell, Sierra Club	Run a scenario on upstream leakage rates of methane from all gas supplies into Washington.	Thank you for your comment.
7/28/2020	Joni Bosh, NW Energy Coalition	NWEC comments and suggestions. Evidently, four supporting documents will have to be submitted separately. Those follow this submission.	Thank you for your comment.
7/28/2020	Joni Bosh, NW Energy Coalition	See Four supporting documents.	Thank you for the four supporting documents. All four documents are provided as part of the Webinar 5 Feedback Form upload package on pse.com.
7/28/2020	Doug Howell, Sierra Club	We do not agree that the social cost of carbon (SCC) should be treated as a "cost adder" or as "fixed" cost. Climate impacts have long been an environmental externality and now with CETA we can internalize this damage in the planning and acquisition processes. As such, PSE needs to treat this externality for what it is: a variable cost. As a variable cost, it needs to be included in PSE dispatch modeling. We do not agree that PSE should characterize this as a carbon tax. Just because you are treating SCC as a variable cost for dispatch modeling, does not make it a tax. It would be tax if it showed up in your annual revenue requirement, which it will not.	Thank you for your comment. PSE will run several sensitivities and scenarios, requested by stakeholders, around the different ways to model the social cost of carbon. Further discussion will occur at the August 11 stakeholder meeting.

Feedback Form Date	Stakeholder	Comment	PSE Response
7/28/2020	Doug Howell, Sierra Club	Incorporate SCC in the dispatch model. Explain why you are not treating this as a variable cost. Explain the calculations for Slide 20, and provide all the data inputs that lead to the results on Slide 20.	Thank you for your comment. PSE will run several sensitivities and scenarios, requested by stakeholders, around the different ways to model the social cost of carbon. Further discussion will occur at the August 11 stakeholder meeting.
7/28/2020	Kyle Frankiewich, WUTC Staff	Questions and comments from presentation: • Slide 18: It seems that the iterative / cyclical / recursive approach to SCC-as-adder might hobble the ability of the portfolio optimizer to 'see' and avoid these costs. I think I'm mostly confused about how the company iterates its carbon emissions estimates to get the $/kw-yr fixed costs correct, and how or whether a thermal plant's run rate is fixed or able to be optimized somewhat by the model. At some point, dispatch must be affected, either through the SCC-in-dispatch or through gas resources becoming too expensive in an after-the-model-run adjustment. • Slide 21: How do SCC-as-adder costs get figured into an optimized retirement plan for existing thermal plants? Are existing plants added as selectable, with increasing kW-yr SCC O&M costs for each iteration of a plant to be retired in, say, 2030 vs 2035 vs 2045? Or, is the fact that the O&M is paid for within the model on a year-to-year basis means that the model can see the SCC-related difference between retiring sooner vs later? • Slide 35: Does the assumption that all gas used for electric generation is from BC align with PSE's historical purchasing patterns for its existing plants?	PSE responses referenced slide numbers: Slide 18: The plants dispatch to gas and electric prices. Using SCC as a fixed cost adder does not affect dispatch since we are not changing gas or electric prices. Running the cyclical process will not change dispatch of the thermal plants. Slide 21: PSE will work on creating a write-up of the AURORA portfolio model to include in the 2021 IRP. Slide 35: PSE's assumption that all gas used for electric generation is from BC does align with historical purchasing. The natural gas for power generation portfolio does not have pipeline capacity from the (US) Rockies.
7/28/2020	Kyle Frankiewich, WUTC Staff	Recommendations: 1. SCC as dispatch cost: I appreciate the discussion around whether SCC should be included outside of dispatch or within dispatch. I agree with Mr. Adcock's question about whether excluding SCC as a 'carbon tax' means PSE is ignoring carbon costs imposed by CETA starting in 2030. Elizabeth stated that the company is modeling CA's carbon tax, and can constrain its fleet by emissions or energy. I also understood that the 80% renewables requirement starting in 2030 is implemented in the model as an RPS standard modeling constraint, rather than the administrative penalty for emitting resources. Please provide some additional explanation on how (or whether) PSE's modeling tools optimize around these constraints. I worry that the constraints may have unintended impacts, and may nudge the optimization in a direction that is, well, suboptimal. I am glad to hear that PSE will be doing some extra test runs to understand the impacts of each approach. 2. WUTC and SCC: Staff recommends using the updated figures on the Commission's website; the table should be updated by the end of July (for its calculation, staff uses BEA GDP Table 1.1.4 Annual Price Indexes Line 1, last revised May 28, 2020). 3. SCC and existing plants – modeling for optimized retirement date: Suggestion more than recommendation – I would encourage PSE to review how plant closures are modeled. I am not sure if I have it right, but I understood from Elizabeth's explanation that PSE's portfolio generation tools will optimize for the closure dates of existing thermal resources. The optimization will solve to the lowest-cost portfolio, and SCC is included in a $/k-/yr fixed cost that changes each year based on the forecasted capacity factor of a thermal plant. This means the optimizer will 'see' costs in each year, and can choose to avoid those costs by closing the plant. 4. Upstream gas emissions – AR4 vs AR5: PSE stated that PSCAA's study and the company's reporting requirements both use 100-yr GWP factors and inputs/assumptions contained in the IPCC's Fourth Assessment Report (AR4), published in 2007, and that the company intends to use these assumptions and inputs for the IRP analysis of upstream emissions. The IPCC released AR5 in 2014, and other scientific studies on this topic have been published in the last few years. The company must support all modeling decisions, including the decision to use either AR4 or AR5 to estimate upstream emissions. Staff recommends a sensitivity comparing estimates calculated using AR4 with those calculated using AR5, so the company and stakeholders can better understand the impacts of this modeling decision. 5. Renewable natural gas / hydrogen – selectable option in model: These resources are clearly not as commonplace as mature products like recips or even batteries, but it's been demonstrated by other utilities (NextEra, NW Natural) that the technology is proven enough to be explored in both integrated planning and through pilots. NW Natural's last IRP (pg 6.30) should provide a good starting point. I see that the company heard feedback from stakeholders on this issue during its first IRP meeting. I look forward to continued discussion when we reach the portfolio modeling phase.	PSE responses by referenced numbers: 1. PSE will be running sensitivities around SCC and possible dispatch limits around plant emissions. Further discussion will occur at the August 11 stakeholder meeting. 2. When the updated numbers are available, PSE will update to the new price index. 3. Yes, the model runs simulations using perfect foresight. Knowing what costs will be in the future, the model looks at the economics of retiring a plant earlier and replacing it so that it does not incur more costs in the future versus maintaining the plant for a higher cost. 4. PSE will include a sensitivity for AR5. Further discussion will occur at the August 11 stakeholder meeting. 5. PSE is researching RNG and hydrogen as a fuel source. 6. The complete list of scenarios and sensitivities will be available for the August 11 webinar and will revised with stakeholder feedback. 7. PSE will run several sensitivities and scenarios around the different ways to model the social cost of carbon. PSE filed comments with the Washington Utilities and Transportation Commission (WUTC) under UE-191203, https://www.utc.wa.gov/docs/Pages/DocketLookup.aspx?FilingID=191023. Comments on the social cost of carbon begin on page 17, question 9. A discussion of the SCC modeling will also be included in the IRP book.

Feedback Form Date	Stakeholder	Comment	PSE Response
		6. Catalogue of scenarios and sensitivities: This might already be part of the company's plan, but if not, Staff recommends that the IRP contain a narrative description of scenarios and sensitivities the utility used, including those informed by the public participation process. 7. Written rationale on SCC modeling decision: Not a recommendation, but a suggestion to invest the time necessary to fully explain, either in the consultation update or the IRP itself, why the company is using the SCC-as-adder approach. A useful write-up would include an analysis the pros and cons for the company's implementation of SCC as a fixed cost rather than as a dispatch cost, for example, and would clearly specify how, in the company's view, this implementation meets CETA's requirements for resource planning and conservation. This explanation would be augmented by a comparison of the company's main model outputs with the SCC-at-dispatch scenario, which should show the relative impact of this modeling decision. If the company plans on compiling the list of scenarios and sensitivities, I hope this explanation and comparison of the two model runs would be a manageable lift.	

PSE IRP Consultation Update
Webinar 5: Social Cost of Carbon
July 21, 2020

8/11/2020

The following consultation update is the result of stakeholder suggestions gathered through an online Feedback Form, collected between July 14 through July 28, 2020 and summarized in the August 4, 2020 Feedback Report. The report themes have been summarized and along with a response to the suggestions that have been implemented. If a suggestion was not implemented, the reason is provided.

PSE thanks Kyle Frankiewich (WUTC) for providing the recently updated inflation adjustment of the social cost of carbon pursuant to docket U-190730 Order 01 referenced below.

PSE also thanks Charlie Black and Orijit Ghosal of Invenergy, Joni Bosh of Northwest Energy Coalition (NWEC), Rob Briggs of Vashon Climate Action Group and Eleanor Bastion of Washington Environmental Council for meeting with PSE on August 10 to help further clarify their questions and suggestions concerning Invenergy's proposal for an environmental externalities approach to the modeling of the social cost of carbon in the 2021 IRP.

Special thanks to Joni Bosh of NWEC who alerted PSE that we missed the feedback form submitted by NWEC in the feedback report. The letter from Joni Bosh and Fred Huette of NWEC has been uploaded to the PSE IRP website and will be addressed separately via addendums to the feedback report and this consultation update. The referenced letter is available here:
https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/July_21_webinar/Attachment_9_NWEC_Comments_on_SCC_in_IRP.pdf

Social cost of carbon inflation adjustment

An inflation adjustment of the social cost of carbon was referenced by Kathi Scanlan of the WUTC at the July 21 meeting. On July 30, the commission published docket U-190730 Order 01 “Adopting an Adjusted Cost of Greenhouse Gas Emissions Reflecting the Effect of Inflation”. The Order is attached to this consultation update. PSE will update the numbers used for the 2021 IRP modeling. The “Emission Price Calculations workbook.xls” spreadsheet has been updated on the PSE IRP website to reflect this latest guidance from the WUTC. The updated spreadsheet name is “Emission Price Calculations workbook (Inflation Update)” and is available here: https://pse-irp.participate.online/meeting/july-21-2020-social-cost-of-carbon-and-upstream-emissions.

Upsteam emissions

PSE received feedback from Rob Briggs and Virginia Lohr of the Vashon Climate Action Group, Joni Bosh and Fred Heutte of NEWC and Doug Howell of Sierra Club concerning PSE’s assumptions around upstream natural gas emissions. PSE appreciated the feedback. The modeling protocols described during the webinar will remain consistent with prior modeling efforts and accepted regulatory criteria, and in addition PSE proposes to model a portfolio sensitivity which utilizes the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5) global warming potential (GWP) for greenhouse gas emissions included in upstream emissions.

Social cost of carbon modeling approach

PSE received feedback from James Adcock, Vlad Gutman-Britten (Climate Solutions), Kevin Jones, Virginia Lohr and Rob Briggs (Vashon Climate Action Group), Charlie Black and Orijit Ghosal (Invenergy), Doug Howell (Sierra Club), Joni Bosh and Fred Heutte (NWEC) and Kyle Frankiewich (WUTC) concerning the social cost of carbon modeling approach.

PSE is modeling the social cost of carbon (SCC) as a post-economic dispatch cost. However, PSE proposes to model several portfolio sensititivites and electric price scenarios modeling the SCC as a variable dispatch cost as requested by stakeholders.

PSE models the SCC as a **fixed cost adder** using the following methodology (also described during the July 30th webinar):

1. A long-term capacity expansion (LTCE) model is run to determine portfolio build decisions over the modeling timeframe. Within the LTCE model, the SCC is applied as a penalty to emitting resources (i.e. fossil-fuel fired resources) during each build decision.
    a. The fixed cost adder is calculated as such:
        i. AURORA generates a forecast of dispatch for the economic life of the emitting resource. This dispatch forecast is not impacted by the SCC to simulate real-world dispatch conditions.
        ii. The emissions of this dispatch forecast are summed for the economic life of the emitting resource and the SCC is applied to the total lifetime emissions.
        iii. The lifetime SCC is then applied as fixed cost amortized over the life of the project.
        iv. A new build decision is made based on the total lifetime cost of the resource.
2. The LTCE model results in a portfolio of new builds and retirements. Since the LTCE runs through many simultions a sampling method is used to decrease run, so the final step is to pass the portfolio to the hourly dispatch model, which is capable of modeling dispatch desisions at a much higher time resolution. The hourly dispatch model is not capable of making build decisions, but will more accurately assess total portfolio cost to rate payers. Since the SCC is not a cost passed to rate payers, the SCC is not included as part of this modelling step.

The strengths of this modeling approach include:
- accurate representation of real-world emitting resource dispatch as defined by current regulation
- accurate representation of cost to customers in the build decision
- inclusion of the SCC in all long-term planning build decisions
- distinction between build decisions and dispatch decisions (SCC is not double counted)

The weaknesses of this modeling approach include:
- emissions from thermal resources are not reduced but total portfolio emissions are reduced by less thermal resource builds

Stakeholders have requested that the SCC be included as a **dispatch cost** at all modeling levels. PSE understands this approach as:

1. A long-term capacity expansion (LTCE) model is run to determine portfolio build decisions over the modeling timeframe. Within the LTCE model, the SCC is applied as a penalty to emitting resources duing each build decision as a dispatch cost.
   a. The variable dispatch cost is calculated as such:
      i. AURORA generates a forecast of dispatch for the economic life of the emitting resource. This dispatch forecast is impacted by the SCC which would increase the cost to dispatch the emitting resource, thereby reducing the number of dispatches of the emitting resource.
      ii. The emission costs of this dispatch forecast which already contain the SCC are summed for the economic life of the emitting resource.
      iii. A build decision is made based on the lifetime cost of the resource.
2. The LTCE model results in a portfolio of new builds and retirements. Since the LTCE runs through many simultions a sampling method is used to decrease run, so the final step is to pass the portfolio to the hourly dispatch model, which is capable of modeling dispatch desisions at a much higher time resolution. The hourly dispatch model is not capable of making build decisions, but will more accurately assess total portfolio cost to rate payers. The SCC can either
   a. be included in dispatch decisions to remain consistent with the LTCE model, or
   b. not be included in the hourly dispatch.

The strengths of this modeling approach include:
- inclusion of the SCC in all long-term planning build decisions

The weaknesses of this modeling approach include:
- possible double counting of SCC as both a build and a dispatch decision
- the dispatch of the resources will be optimized to minimize total costs which will result in a change in dispatch that is lower than expected in the real-world
- not reflective of real-world dispatch decisions which can result in a sub-optimal portfolio by underestimating the resource costs
- increased cost to customers

Given the strengths and weaknesses of each modeling approach PSE proposes to model several sensitivities to diagnose the impact of modeling approach on the social cost of carbon. PSE recognizes that there are several variations on these two general approaches and looks forward to discussion with stakeholders on the August 11th webinar to clarify details various sensitivities.

Summary of all updates

PSE appreciates the feedback provided by stakeholders. In summary, the following changes will be implemented into the portfolio model or included in the proposed portfolio sensitivities with stakeholders at the August 11, 2020 webinar:

- Update inflation adjustment of the social cost of carbon consistent with docket U-190730 Order 01 published by the WUTC on July 30, 2020.
- Proposed inclusion of a portfolio sensitivity to model upstream emissions consistent with AR5.
- Proposed inclusion of several portfolio sensitivities to diagnose impacts of various social cost of carbon modeling approached (e.g. cost adder, dispatch cost, externality, tax).

PSE is committed to keeping our stakeholders informed of our progress toward incorportating feedback into the 2021 IRP process.

Webinar #6: Portfolio Sensitivities Q&A

8/12/2020

Overview

On August 11, 2020 Puget Sound Energy hosted an online meeting with stakeholders to discuss portfolio sensitivities, CETA assumptions and Distributed Energy Resources (DERs). Additionally, participants were able to ask questions and make comments using a chat box provided by the Go2Meeting platform.

Below is a report of the questions submitted to the chat box. Answers to the questions were provided verbally by IRP staff during the webinar. Please note that questions were answered in order of relevance to the topic currently being discussed. Questions regarding other topics were answered at the end of the webinar session.

To view a recording of the webinar and to hear responses from staff, please visit the project website at pse-irp.participate.online.

Attendees

A total of 58 stakeholders and PSE staff attended the webinar, plus another 11 attendees who called into the meeting and did not identify themselves (69 people total).

Attendees included: Anne Newcomb, Ashton Davis, Bill Pascoe, Bob Stolarski, Brad Tuffley, Brandon Houskeeper, Brett Rendina, Brian Grunkemeyer, Brian Robertson, Brian Tyson, Charlie Black, Cody Duncan, Colin O'Brien, Corina Pfeil, Michael Corrigan, Dan Kirschner, David Perk, Don Marsh, Fred Heutte, Glenn Blackmon, Harrison Matherne, James Adcock, Jenny Lybeck, Joni Bosh, Kassie Markos, Kate Maracas, Katie Ware, Kevin Jones, Cathy Koch, Kyle Frankiewich, Lorin Molander, Leslie Almond, Marcus Sellers-Vaughn, Margaret Miller, Devin McGreal, Michael Laurie, Mike Elenbaas, Mike Hopkins, Nancy Esteb, Peter Sawicki, Peter Tassani, Rachel Brombaugh, Rahul Venkatesh, Sarah Vorpahl, Sheri Maynard, Stephanie Chase, Stephanie Imamovic, Steve Greenleaf, Susan Christensen Wimer, Ted Drennan, Thomas Cameron, Tom Flynn, Virginia Lohr, Vlad Gutman-Britten, Willard Westre, Elyette Weinstein and Zac Yanez.

Questions Received

Questions from attendees are posted in the order in which they were received. The webinar began at 8:30 AM PDT and ended at 12:48 PM PDT.

Name	Time Sent	Comment
Alison Peters	**8:22 AM**	Good morning, all. Nice to see you this morning.
Virginia Lohr	**8:35 AM**	How do we know the level of public participation before the meeting starts?
Alison Peters	**8:38 AM**	Hi Virginia, the levels are labeled in the PowerPoint deck that was posted a week prior to this webinar. Thanks for asking.
Kevin Jones	**8:43 AM**	Slide 10: What criteria does PSE use to select the "reference portfolio"?
Kevin Jones	**8:44 AM**	Slide 10: Not sure I understand this slide. PSE selects a "reference portfolio", then makes changes to that portfolio "for each portfolio comparison". Is PSE saying that changes made to the "reference portfolio" will allow PSE to evaluate the impacts of these changes on all the other portfolios (each portfolio comparison)?
Kevin Jones	**8:45 AM**	Slide 10: Are the "changes" listed on this slide actually a list of the parameters that are varied to create different sensitivities?
Joni Bosh	**8:47 AM**	Slide 10 – what criteria do you use to select the refernce portfolio?
James Adcock	**8:47 AM**	Hand Raise Slide 9
Kevin Jones	**8:48 AM**	Participants - Go To Meeting default is set so your chat messages go only to EnviroIssues. You can change that setting to "everyone" to receive your chat messages in the pulldown menu next to the chat "To" line. Please do that.
Kevin Jones	**8:48 AM**	Slide 10: Not sure I understand this slide. PSE selects a "reference portfolio", then makes changes to that portfolio "for each portfolio comparison". Is PSE saying that changes made to the "reference portfolio" will allow PSE to evaluate the impacts of these changes on all the other portfolios (each portfolio comparison)?
Kevin Jones	**8:48 AM**	Slide 10: Are the "changes" listed on this slide actually a list of the parameters that are varied to create different sensitivities?
Alison Peters	**8:49 AM**	Thanks Kevin. I see you've shared your question with everyone now.
Fred Heutte	**8:49 AM**	slide 9: "The purpose of a scenario is to create a 20-year electric price forecast" -- isn't the purpose of a scenario to create a resource portfolio that includes a price forecast and other factors?
Fred Heutte	**8:51 AM**	Slide 13: what is meant by "themes"
Kyle Frankiewich	**8:57 AM**	Slide 9/10: I am also confused by the distinction between scenarios and forecasts. Are "scenarios" model runs where something outside of PSE changes, and "sensitivites" runs where PSE's resource choices are altered?
Joni Bosh	**8:59 AM**	Slide 14 – just to clarify, are you saying the items on this slide are themes?
Don Marsh	**9:00 AM**	On slide 14, I think a key issue is the increasing capacity and decreasing costs of technologies like solar panels, batteries, smart grid, etc. Given the considerable impact on the industry, these developments qualify as a "key issue."
James Adcock	**9:00 AM**	Slide 14 -- where does availability / CETA applicability of RECs fit in here?
Corina Pfeil	**9:00 AM**	When would that happen

Michael Laurie	**9:03 AM**	On slide 10 you have chosen conservation as one of the changes that you may include. I strongly suggest that you include it because if significant conservation is achieved it will reduce the need for additional power plants including peaker plants. And most conservation is cheaper than new power plants and does not face a risk that natural gas plants face of being outlawed by future legislation at the state and federal level. So it will help PSE to stay consistent with providing energy at lowest cost to their customers. And with some many laws having been passed at the state level that will increase conservation and uncertainty of how much conservation they will achieve PSE should include different scenarios of high, medium, and low conservation being achieved by these laws. And absoluteluy support increase the ramp rate to 6 years.
Willard Westre	**9:04 AM**	Raise Hand S-16
Alison Peters	**9:05 AM**	Hi Corina. Could you send your question to “Everyone” and clarify what you meant? THank you.
Kyle Frankiewich	**9:05 AM**	Slide 16: really like this slide. Have a bunch of Qs but will save them for later when we get into the details.
Michael Laurie	**9:06 AM**	Is PSE looking at a sensitivity related to a much more wholistic approach to conservation including approaches that make wholistic conservation easier to achieve?
James Adcock	**9:06 AM**	Slide 16 -- what do you mean by "renewable overgeneration?" If you have too much reneable capacity just don't run all of it. How is this different than having too much NG Peaker capacity at a given point in time? If you don't need that NG Peaker capacity just don't run it. So I don't understand what you are saying here?
Virginia Lohr	**9:07 AM**	What is the range of the number of sensitivities you anticipate being able to run? I'm wondering about how many might need to be dropped. For example, do you anticipate only 1 or 2 being left under a "theme" or "issue"?
Vlad Gutman-Britten	**9:08 AM**	80% clean delivered to load?
Charlie Black	**9:08 AM**	I strongly encourage PSE to place a high priority on analyzing the SCC as an environmental externality. The SCC should be included as a variable cost of dispatch. This approach is the most consistent implmentation of the CETA requirements to include the SCC in IRP.
Joni Bosh	**9:10 AM**	Back on RECs – why can’t the model sell the over generation with its RECs?
Anne Newcomb	**9:14 AM**	On slide 16 under Emissions Reductions: What do you think about adding Hydrogen as well as biodiesel?
James Adcock	**9:17 AM**	+1 Charlie
David Perk	**9:17 AM**	Agree with Charlie Black’s comment re SCC.
Joni Bosh	**9:19 AM**	+1 Charlie
Don Marsh	**9:19 AM**	Did Elizabeth have a response to Charlie’s suggestion?
Corina Pfeil	**9:21 AM**	agreed
David Perk	**9:22 AM**	Absolutely agree with Charlie
Don Marsh	**9:22 AM**	Also agree.
David Perk	**9:22 AM**	PSE needs to get SCC right, from the start

Elyette Weinstein	**9:22 AM**	Penny's method causes confusion and inhibits transparency.
Kate Maracas	**9:23 AM**	Stakeholders: I suggest that you frame your comments as questions so that they can be addressed.
Virginia Lohr	**9:24 AM**	Does over generation consider using it to make renewable hydrogen?
Kyle Frankiewich	**9:24 AM**	Slide 18: I'd like to better understand what is going into the low-growth scenario, as this economic downturn could last longer than we'd hope, and the changes in energy use (substantial work from home, lower office energy use, etc) could well become permanent.
Willard Westre	**9:24 AM**	S18- Agree with Charlie
James Adcock	**9:24 AM**	Agree with Charlie that I not including SCC in all aspects of IRP and REC modeling of dispatch [as opposed to PSE's approach of modeling it [incorrect] as a "fixed cost] is a "fatal error" which destroys any value to PSE's entire IRP and RFP efforts, including analysis of DR and Conservation.
Willard Westre	**9:24 AM**	Agree with Charlie
Elyette Weinstein	**9:25 AM**	Where do questions end and statements begin? Observations logically include statements which cause the questions? Is Penny serving as a PSE advocate or partial judge? She should be a neutral party that is impartial.
Charlie Black	**9:24 AM**	Thanks, Kate. I was just thinking the same thing.
Elyette Weinstein	**9:26 AM**	I agree with Charlie.
Don Marsh	**9:27 AM**	When meeting efficiency is valued more than honest inquiry and conversation, the process needs to be rethought. I encourage meeting organizers to do some soul searching regarding the fairness of this process.
James Adcock	**9:27 AM**	Slide 18 Raise Hand.
Michael Laurie	**9:27 AM**	Is it true that PSE is considering selling some of their transmission lines from Montana? If so why sell transmission when that could allow transmission of wind resources with a high capacity factor?
Elyette Weinstein	**9:27 AM**	Thank you Don!
Kyle Frankiewich	**9:28 AM**	slide 19: Market reliance presumes a) availability of sellers at Mid-C, and b) functioning Tx that can move that power to load. I understand that this will be modeling a). Are these sensitivities and scenarios stochastic in nature? Do they get an idea of what PSE's risks are in relying on key infrastructure, ie, the 1500 MW Tx backbone into MidC? I'm generally puzzled about when stochastic modeling and the mixing and matching of load shapes vs renewable generation shapes gets analyzed.
Vlad Gutman-Britten	**9:30 AM**	Support the use of hydrogen as long term storage, but hydrogen also is a commodity with independent market value. It would be good to model both potential dispositions of hydrogen--as a marketable product to financially benefit customers and as a system resource, including how it may support compliance with CETA.
Anne Newcomb	**9:30 AM**	If you have an excess of Renewable energy before 2045, can it be used rather than any fossil fuels that may be in the mix at the moment?
Corina Pfeil	**9:31 AM**	Yes

Willard Westre	**9:34 AM**	Hand Raised S-20
Fred Heutte	**9:35 AM**	responding to comment by Elizabeth: renewables can be held as reserves, there is nothing preventing that and as costs continue to fall it will become reasonable to do so
Fred Heutte	**9:35 AM**	That allows renewables to be used for both incs and decs
James Adcock	**9:36 AM**	Slide 20 raise hand.
Fred Heutte	**9:36 AM**	in addition renewables and other inverter based resources with power electronics respond to dispatch signals much faster and with more fidelity than thermal
Kate Maracas	**9:37 AM**	+1 to Fred
Don Marsh	**9:37 AM**	Fred, lots of good comments. Maybe you need to ask a question?
Fred Heutte	**9:38 AM**	that was a comment not a question
Don Marsh	**9:39 AM**	Not necessary for PSE to address in this meeting? I think an answer might clarify a few things, but it's up to you.
Virgina Lohr	**9:41 AM**	I agree with Bill Westre
Michael Laurie	**9:41 AM**	I also agree with Bill Westre. I think it is a key element because of the options for renewables and storage in Montana.
Bill Pascoe	**9:43 AM**	Raise Hand Slide #20
Don Marsh	**9:44 AM**	PSE says it needs to build new transmission capacity to handle renewables. I don't understand how selling the Montana lines is a benefit to PSE's ratepayers. I'd really like to understand the econmic benefits of that sale.
James Adcock	**9:44 AM**	In terms of "comments" vs. "questions" PSE's lawyer in the cover letter to PSE's current RFP draft claims that PSE's IRPs include "discussion" which PSE seems to be clearly actively *preventing* by not responding to comments -- only to questions.
Vlad Gutman-Britten	**9:45 AM**	With conservation and other DERs, are you evaluating any equity metrics consistent with CETA? Distributional impacts/benefits, etc?
Michael Laurie	**9:45 AM**	Slide 21 could you also include here the idea of a more wholistic approach to conservation as I mentioned earlier?
Corina Pfeil	**9:45 AM**	Ramp Rate - nomaly also indicates systemic rate increses to customers - are you intending to make rate increase over the next year ?
James Adcock	**9:46 AM**	Slide 21 Raise Hand.
Corina Pfeil	**9:46 AM**	Considering the COVID Pandimic - most agencies are freezing customer increases over the year -
Willard Westre	**9:48 AM**	S-21 Will the 2.5% cost of financing be applied to generation assets as well?
Don Marsh	**9:48 AM**	Elizabeth says if you increase the conservation ramp rate, PSE will do less conservation later. However, the 10-year ramp rate has been used in several IRPs, and I see no reduction of conservation on the horizon. Does this really work the way Elizabeth is describing?
Corina Pfeil	**9:48 AM**	Low income, Seniors, and Disabled, along with Race
Corina Pfeil	**9:48 AM**	Thank you Vlad
David Perk	**9:48 AM**	+1 Vlad's comment re deeper work on equity
David Perk	**9:48 AM**	Particularly in the current economic environment

Michael Laurie	**9:51 AM**	The answer of thank you to my suggestion about looking at a wholistic approach does not tell me whether you will look at it or not. Do you plan to look at it? or not? Or are you unsure?
Kyle Frankiewich	**9:53 AM**	slide 21: I'm still trying to make sense of the value stream of DR. I think one of the bigger values of DR might be its ability to hedge against the risk of super-peak events, which might not be immediately visible in a determinative model run. Can PSE identify other scenarios and sensitivities that are more likely to miss some hard-to-see risks or benefits?
Fred Heutte	**9:54 AM**	slide 22 hand raise: NWEC supports the use of AR5 for sensitivity 21. Will PSE also run a separate sensitivity for an updated emissions rate for upstream emissions, for example the EDF Low rate as we have suggested?
Don Marsh	**9:55 AM**	Kyle's question is good. DR provides reliability and resiliency benefits that might not be fully captured in the economic model. I worry about that. Reliability is very valuable to residents and businesses.
Vlad Gutman-Britten	**9:56 AM**	It would be very helpful to model SCC in absense of 2030 and 2045 portfolio requirements to better understand the impact of modeling SCC on dispatch and post dispatch. I'm reading these SCC sensitivities as being in context of the portfolio requirements which your previous models have shown to yield little impact for SCC.
James Adcock	**9:57 AM**	Slide 22 Raise Hand.
Michael Laurie	**9:58 AM**	What is the economic reasoning for using a fixed cost of carbon at dispatch when the amount of carbon based energy that is used at dispatch will be a variable demand that is not possible to predict ahead of time. A fixed cost for a variable activity is hard to understand.
Virginia Lohr	**9:58 AM**	Raise Hand: Slide 23, Sensitivity 22
Joni Bosh	**10:00 AM**	+1 kyle
Michael Laurie	**10:01 AM**	What is the reasoning for using the very low federal tax of $15/ton. If it were to come to pass it would likely come to pass if the federal government is controlled by Democrats and in that scenario there will be strong pressure to have a much higher tax.
Vlad Gutman-Britten	**10:02 AM**	Support Fred's recommendation for a sensitivity estimating high leakage rates for NG.
Virginia Lohr	**10:03 AM**	I also strongly support what Fred Heutte is saying.
Joni Bosh	**10:04 AM**	Clarification on #23 - is this one modeled like 19 or 20?
Kyle Frankiewich	**10:05 AM**	Q for Jim Adcock: Are you looking for a layered scenario that includes both SCC at dispatch and with various tweaks to conservation ramp rates?
Vlad Gutman-Britten	**10:05 AM**	Hand raised on SCC.
Charlie Black	**10:06 AM**	Raise hand on SCC
Michale Laurie	**10:10 AM**	Agree with Virginia Lohr on using a higher federal tax in the analysis.

James Adcock	**10:10 AM**	Answer to Kyles question posed to me: I read CETA as *requiring* Puget to always include social cost of carbon in *all* aspects of IRP and RFP *all of the time* up to and including actual purchase of resources including DR and Conservation, as such I believe Puget is *required* to include SCC as a variable dispatch cost in *all* of their modeling efforts re IRP and RFP, not just the "base case." So from my point of view its not a question of which "portfolios" or "schenarios" should include SCC in dispatch, because I believe Puget is *required* by CETA to include SCC in dispatch in *all* of them.
David Perk	**10:12 AM**	Agree with Charlie Black's SCC comments.
James Adcock	**10:13 AM**	...in comparison if Puget for a private business analysis reason *not* part of the IRP or the RFP wants to *not* include SCC in that private business modeling that would be Puget's business, not ours.
David Perk	**10:13 AM**	Important to get SCC right, from the beginning
Charlie Black	**10:14 AM**	Raise hand
Joni Bosh	**10:14 AM**	Agree with Charlie Black's request.
Virginia Lohr	**10:17 AM**	SCC is a variable cost and should NOT be run as a fixed cost.
Kyle Frankiewich	**10:18 AM**	+1 on Vlad's suggestion - will provide a an interesting perspective on the impact of SCC compared to other CETA reqs
Virginia Lohr	**10:19 AM**	Raise Hand: Slide 24, Sensitivity 25.
Don Marsh	**10:19 AM**	Slide 24, sensitivity 24: Stakeholders are concerned that PSE is using prices for batteries that are too high. During the transmission constraints webinar, PSE showed exorbitant costs for connecting batteries which made no sense to us. Have these issues been corrected?
Elyette Weinstein	**10:20 AM**	I agree that SCC is a variable cost and should NOT be run as a fixed cost.
Don Marsh	**10:22 AM**	Thanks for the correction on battery interconnection costs. But are you still modeling 5 miles of transmission to connect batteries? That also made no sense. Batteries are typically sited close to existing transmission. Was that corrected?
Don Marsh	**10:23 AM**	Also, what is the basis of PSE's cost for the batteries themselves? We have seen significantly lower prices used by Portland General Electric. Maybe PacifiCorp too.
Michael Laurie	**10:23 AM**	Agree with Virginia Lohr's point that since there are limitations on what can be limited it is better to model hydrogen instead of biodiesel.
Kevin Jones	**10:23 AM**	raise hand slide 24

James Adcock	**10:24 AM**	Re batteries, in RFP Puget dismissed my concerns that transmission costs which are 1600% too high, in part because it appears PSE assumes a 5 mile interconnect cost, but in my aerial photographic review of recent actual "state of the art" battery storage systems, the actual connection length is only about 0.1 miles -- because battery systems can be sited "anywhere" -- and so real peer utlities of Puget are siting them "as close as possible" to existing infrastructure -- no additional stub line required -- next to either an existing solar or wind facility, or next to an existing substation -- so that transmission interconnect costs are minimized. In addition Puget was estimating Battery Storage cost for the base facility 53% higher than NREL estimates. These estimates seem to be so extremely high as to prohibit any fair modeling of Battery Storage [as competition to NG Peakers] at at all.
James Adcock	**10:25 AM**	Raise Hand “Transmission Interconnect Costs.”
Don Marsh	**10:26 AM**	Thanks for actual data on battery costs, James Adcock. Very useful. I encourage PSE to correct the exaggerated assumptions that seem to be skewing the models against batteries.
Don Marsh	**10:27 AM**	Many utilities are finding batteries are much more practical than PSE is. For example, PacifiCorp and Portland. PSE must fix the skewed analysis.
Don Marsh	**10:28 AM**	We look forward to clarity on those battery costs. Thanks for looking into it!
Dan Kirschner	**10:28 AM**	Raise Hand Slide 25
Vlad Gutman-Britten	**10:28 AM**	Hand raised on sensitivity 30
Charlie Black	**10:29 AM**	Raise hand on process for responding to requests by stakeholders.
Don Marsh	**10:29 AM**	Sensitivity 31: Does the sensitivity also include higher temperatures reducing winter peak?
Michael Laurie	**10:29 AM**	Is PSE looking at other Demand adjustments like control of hot water tanks, conservation, using batteries to reduce peak demand and more?
Virginia Lohr	**10:30 AM**	Please give us more detail on how you will be doing your temperature sensitivity. What you have is too vague to mean anything.
Don Marsh	**10:31 AM**	In sensitivity 31, is the temperature trend based on the last 10-15 years of rising temperatures? PSE has been using much longer trends that reduce the impact of recent climate trends.
James Adcock	**10:32 AM**	Slide 25 Raise Hand.
Fred Heutte	**10:34 AM**	On #31, the NW Council is finalizing an important assessment of climate change effects on regional temperature, precipitation, demand and hydro runoff.
Fred Heutte	**10:36 AM**	See for example the presentation at the Council's Power Committee yesterday: https://www.nwcouncil.org/sites/default/files/2020_08_p3.pdf
Virginia Lohr	**10:37 AM**	I’m glad to see consideration of a summer peak.
Fred Heutte	**10:37 AM**	The Council staff assessment now shows that climate effects are already observed in the historical record and will continue through the 2020s and beyond.

Don Marsh	**10:37 AM**	Is PSE anticipating any V2G development in the near future? That could dramatically change the amount of battery resource available during the next decade.
Fred Heutte	**10:38 AM**	A significant result is the upward shift in late summer demand peak and somewhat reduced hydro runoff.
Don Marsh	**10:39 AM**	+1 on specificity on temperature trends
Kyle Frankiewich	**10:41 AM**	Slide 25: What might help is for PSE to provide PSE's current weather baseline so that folks can provide substantive input on #31. Would that be feasible?
Michael Laurie	**10:42 AM**	Agree with Don about looking at vehicle batteries as a major demand management resource.
Anne Newcomb	**10:44 AM**	Great job Everyone!!! :-) Thank You!
Vlad Gutman-Britten	**10:45 AM**	Thanks everyone.
Charlie Black	**10:48 AM**	Re-raising my hand on process for PSE following up on requests by stakeholders.
Fred Heutte	**10:56 AM**	raise hand for upstream emissions factor
Don Marsh	**10:57 AM**	We could do some research to see what other utilities are doing regarding V2G. I don't know now whether it's a sensitivity, but by ignoring the possibility, PSE might be creating a significant blind spot for future planning.
Joni Bosh	**10:57 AM**	Question on Excel sheet - can we submit suggestions later, as we have time to look at the corrected version.
James Adcock	**10:58 AM**	For the record: I would "want" to have SCC modeled as a variable cost of dispatch, not a fixed cost, in every one of these Portfolio Analysis conditions, because that is what I understand as being required by the CETA law.
Virginia Lohr	**10:58 AM**	Are you entering what we have already requested today?
Don Marsh	**10:58 AM**	Does PSE's demand response portfolio include time-of-day pricing? Until energy costs are better reflected in retail prices, we are ignoring the significant effects of market forces. With history as our guide, it's not smart to do that.
Michael Laurie	**10:59 AM**	Raising my hand to include a sensitivity to include a Wholistic approach to conservation. Basically assuming most conservation efforts carry out the majority of possible and cost effective conservation in each building instead of the piecemeal limited measures approach which has been the case for most PSE and other utility efforts.
Don Marsh	**11:02 AM**	During PSE time-of-day trial 20 years ago, PSE discovered an unexpected conservation effect in addition to peak shifting. That would be beneficial for the environment as well as ratepayer wallets.
Vlad Gutman-Britten	**11:02 AM**	Two sensitives--SCC as adder and in dispatch in absence of portfolio requirements.
Alison Peters	**11:03 AM**	Replying to all re: Joni's question: Yes, please submit suggestions via the Feedback Form online by August 18.
Joni Bosh	**11:03 AM**	Thanks
James Adcock	**11:04 AM**	Raise Hand.
Michael Laurie	**11:04 AM**	I agree that time of day pricing should be looked at. Without it demnd responses options will be underutilitized.
Michael Laurie	**11:06 AM**	Agree with using higher and rising cost for federal carbon tax.

Don Marsh	**11:07 AM**	I like this spreadsheet exercise. It feels like our suggestions are considered. Thank you.
Joni Bosh	**11:11 AM**	I believe Charlie's clarification is correct.
Don Marsh	**11:14 AM**	Raised hand
Kyle Frankiewich	**11:14 AM**	raised hand
Vlad Gutman-Britten	**11:15 AM**	Thanks Elizabeth for including EIA in the SCC-only sensitivities. That is correct.
Vlad Gutman-Britten	**11:15 AM**	(or whoever is typing)
Charlie Black	**11:16 AM**	Raise hand
Michael Laurie	**11:17 AM**	I agree with Don to start out looking early on at using a variable social cost of carbon. And use that result to guide further modeling of a variable social cost of carbon especially at Dispatch.
Willard Westre	**11:20 AM**	Agree with Charlie
Elyette Weinstein	**11:20 AM**	I agree with Charlie
James Adcock	**11:21 AM**	Raise Hand.
Charlie Black	**11:21 AM**	Raisew hand
Don Marsh	**11:22 AM**	PSE's diligence, fairness, and transparency on the analysis of these sensitivities is SO important for all of us. I am hoping that we will all agree in the end that PSE earned an A+ grade on this. If the results seem opaque or skewed in some way, it is going to damage relationships that need healing at this point. Please do a great job!
Charlie Black	**11:23 AM**	Agree with Joni – 2019 analysis treat SCC as a tax, not as an externality.
Vlad Gutman-Britten	**11:23 AM**	They did it both ways.
Charlie Black	**11:24 AM**	Raise hand
Michael Laurie	**11:24 AM**	How could raising the price of a resource at dispatch, using a variable social cost of carbon at dispatch, not reduce the demand for that resource and increase the demand for competitive resources which are now cheaper in comparison because they don't have that social cost of carbon?
Vlad Gutman-Britten	**11:25 AM**	Because the implicit carbon price of CETA is higher than SCC.
Don Marsh	**11:25 AM**	Raise hand
James Adcock	**11:26 AM**	+1 Charlie's Comments
Kyle Frankiewich	**11:29 AM**	raised hand
Virginia Lohr	**11:29 AM**	Pleaseask Maichael Laurie's question
Kyle Frankiewich	**11:31 AM**	oh, never mind - I see that a copy of the spreadsheet Elizabeth is sharing with us is also posted online. I'll populate a copy of that spreadsheet and add to it, then include it with staff's comments
Michael Laurie	**11:32 AM**	Don is making a major point about the importance of including time of day rates to properly analyze demand management options. Without time of day rates many demand management options will be undervalued and underutilitzed.

James Adcock	**11:35 AM**	When you decrease the dispatch of an *emitting* plant then you are increasing the use of *non-emitting* plants, conservation, and dispatch -- which is the whole point of the CETA law and the detailed *requirements* of that law, including its requirements about how PSE performs their IRP and RFP analysis.
James Adcock	**11:43 AM**	For the record: It appears PSE is skipping presentation of slides 30 to 36 due to "time constaints."
Fred Heutte	**11:45 AM**	hand raise for a question on slide 43
Penny Mabie	**11:46 AM**	Yes, James, PSE is skipping slides 30 to 36 today. Those slides will be included in the September 1 webinar.
James Adcock	**11:47 AM**	Thank you!
Brian Grunkemeyer	**11:48 AM**	To integrate DER's, are you considering a technique like dynamic price forecasts to tell DER's when to operate and/or shift load?
James Adcock	**11:52 AM**	Raise Hand.
Michael Laurie	**11:56 AM**	Thanks for working on and planning to propose a community solar program. This gives those who don't have good solar access to invest in solar and it gives communities more options.
Charlie Black	**11:58 AM**	Specific requests regarding PSE's side-by-side modeling of SCC as a variable cost of dispatch and as an annual fixed cost:
Don Marsh	**11:58 AM**	Slide 48: Is PSE doing any experiments with "Virtual Power Plants" (coordinated small batteries to provide reliability and resilience)?
Michael Laurie	**11:59 AM**	How are installed costs looking when comparing utility batteries versus batteries in customer buildings? And what costs are included in that analysis?
Kevin Jones	**12:00 PM**	To what extent are the solar projects you mentioned PSE owned versus "publicly" owned by the community members? To what extent does PSE promote and encourage public ownership of these types of resources?
Charlie Black	**12:01 PM**	1. In the SCC as a variable cost of dispatch sensitivity, dispatch a GHG-emitting resource when the Mid-C spot market price exceeds the sum of the resource's variable cost plus the SCC
Michael Laurie	**12:01 PM**	Thanks for saying that you are looking at how can the grid respond these battery storage options.
Charlie Black	**12:02 PM**	2. In the SCC as fixed cost, dispatch a GHG-emitting resources when the Mid-C spot market price exceeds the resource's variable operating cost.
Don Marsh	**12:03 PM**	Jens said DERs and NWAs are now becoming lower cost than transmission lines. Totally agree. When was that analysis last updated for PSE's "Energize Eastside" project, which will cost ratepayers hundreds of millions of dollars?
Charlie Black	**12:05 PM**	3. In the modeling results for each sensitivity, track and report the quantity of power generated by each type of GHG-emitting resource. Provide a comparison of the quantities of generation for each type of GHG-emitting resource in the two sensitivities.
Charlie Black	**12:12 PM**	4. In the results from the side-by-side senstivities, also provide the amounts and timing of additions of any new GHG-emitting generating resources to PSE's resource portfolio.
Don Marsh	**12:16 PM**	Would ADMS be able to coordinate many small residential batteries? Or do you need additional software to implement a VPP?

Michael Laurie	**12:17 PM**	Are you considering customer based software.thermostat systems that allow the customer to input which of their resources can be temporarily or permanently shifted to off-peak hours and compares that to PSE's peak demand times and then makes choices to shift customer loads to off-peak times?
Anne Newcomb	**12:18 PM**	What ADMS software platform will you be using?
Fred Heutte	**12:19 PM**	raise hand on slide 54 concerning hosting capacity analysis
Michael Laurie	**12:20 PM**	To add to my question about customer based software/thermostat systems to guide customer based peak demand reduction; I understand that there may not be any such systems out there now but with work by some of the techies around here such systems could likely be developed.
Willard Westre	**12:21 PM**	S-53 does AMI allow for Dr control features
James Adcock	**12:23 PM**	Comment: To state it again, PSE needs to figure out how to appropriately apportion the costs of these modernization efforts as being "directly related" to CETA or not, in particular in regards to the CETA 2% offramp. There are modernization efforts, including for example the ability to "remotely disconnect" a customer, which might be things that a utility might want to have, and might even claim is cost-effective -- but which would not be "directly related" to CETA requirements.
Fred Heutte	**12:27 PM**	here's the 2017 IREC reference on hosting capacity analysis: https://irecusa.org/publications/optimizing-the-grid-regulators-guide-to-hosting-capacity-analyses-for-distributed-energy-resources/ plus a more recent article and research paper: https://pv-magazine-usa.com/2020/06/16/solar-hosting-capacity-maps-must-be-accurate-to-be-useful/
Kyle Frankiewich	**12:28 PM**	i'm able to stay on for a bit longer
Don Marsh	**12:28 PM**	I can stay.
Michael Laurie	**12:28 PM**	I am happy to stay longer.
David Perk	**12:29 PM**	there's no where I'd rather be ;-)
Fred Heutte	**12:34 PM**	Hand raise for question about slide 57
Joni Bosh	**12:34 PM**	Slide 55 – do you consider the BI batteries part of a microgrid?
Don Marsh	**12:35 PM**	We love your solution on Bainbridge. So sad that you didn't use the same solution in Bellevue, where PSE decided to cut down 300 beloved community trees to connect two substations, the opposite of what the company did in Bainbridge. We hope not to see that again.
Kyle Frankiewich	**12:35 PM**	would like to hear more about that 20 MW heuristic for NWAs
Kyle Frankiewich	**12:37 PM**	slide 58: to clarify, PSE knows that some projects will select NWAs, and that those NWAs will involve DERs. So, some resources are included in the portfolio as must-take to reflect that cost-effective NWAs will be taken, and are likely to contribute to the company's resource stack. Is that right?
Michael Laurie	**12:39 PM**	Agree with Fred's point. Since the new law requires all hot water tanks to have a communication port to allow controlling them.
James Adcock	**12:42 PM**	Slide 60 Raise Hand.

PSE IRP Feedback Report
Webinar 6: Portfolio Sensitivities
August 11, 2020

8/25/2020

The following stakeholder input was gathered through the online Feedback Form, from August 4 through August 18, 2020. PSE's response to the feedback can be found in the far-right column. To understand how PSE incorporated this feedback into the 2021 IRP, read the Consultation Update, which will be released on September 1, 2020.

Feedback Form Date	Stakeholder	Comment	PSE Response
8/11/2020	Don Marsh, CENSE	I am attaching a recommendation that PSE seriously consider Vehicle-to-Grid technology in the next 5-10 years to take advantage of idle car batteries to store increasing amounts of renewable energy from variable sources like wind and solar.	Thank you for your suggestion concerning a demand response Vehicle-to-Grid technology scenario. PSE will be asking stakeholders to prioritize the sensitivities during the October 20 IRP meeting. To address Vehicle-to-Grid specifically, this is a distributed energy storage resource and it is captured as part of the distributed batteries that we are modeling in the 2021 IRP. We acknowledge that your suggestion could be a lower cost than installing a new battery system. As a response to your input, we have included a sensitivity with a lower cost for batteries in the updated "Scenarios and Sensitivities" excel file located here located in the meeting materials for Webinar 6. This suggestion is also relevant to stakeholders who are concerned about the (high) interconnection cost for batteries. Thank you again for the contribution.
8/11/2020	Don Marsh, CENSE	Please take this seriously for the sake of your customers, the environment, and the long-term health of your company.	Thank you for your comment, thoughts, and suggestions.
8/12/2020	Don Marsh, CENSE	Attached is a request for PSE to include a time-of-use sensitivity in its studies of Distributed Energy Resources. Such programs can save money, increase reliability, and reduce greenhouse gas emissions. These are goals that are mandated by Washington's Clean Energy Transformation Act.	Thank you for your suggestion concerning a demand response time of use scenario and the attachment, as well as the four supporting documents. All of the documents you provided have been uploaded as part of the Webinar 6 Feedback Form package on pse.com/irp. PSE will be asking stakeholders to prioritize the sensitivities during the October 20 IRP meeting. Concerning PSE's current work regarding time of use, PSE is modeling a critical peak price demand response program as part of the resource alternatives.
8/12/2020	Don Marsh, CENSE	If a time-of-use sensitivity is not included, please explain to stakeholders why not.	Thank you for your suggestion concerning a demand response time of use scenario. PSE will be asking stakeholders prioritize the sensitivities during the October 20 IRP meeting.
8/13/2020	Michael Laurie, Watershed LLC	I strongly support the submissions you received from Don Marsh on Time of Use Sensitivity and Vehicle to Grid potential. I think these will be 2 key needed pieces in adapting the grid and PSE's energy supply to our changing world and to the need to rapidly transition to a climate friendly energy system. Thanks	Thank you for expressing your support of Don Marsh's suggestions for sensitivities. PSE will be asking stakeholders prioritize the sensitivities during the October 20 IRP meeting. PSE has included your support in the updated "Scenarios and Sensitivities" excel file.
8/13/2020	Don Marsh, CENSE	I attached a request to study Virtual Power Plants to save customers money, to provide better reliability and resiliency for our energy grid, to reduce greenhouse gas emissions, and to provide local jobs at a time when the economy could use some assistance without taxpayer funds.	Thank you for your request to study Virtual Power Plants (VPPs) and the attachment you provided. VPPs are a platform to find the best use of distributed energy resources (DER) on the grid and are included on PSE's grid modernization road map. PSE is evaluating distributed resources in the 2021 IRP.
8/13/2020	Don Marsh, CENSE	The 2021 should have a sensitivity assessing the potential of VPPs to help achieve CETA goals.	Thank you for your suggestion of a 2021 IRP sensitivity assessing the potential of VPPs to help achieve CETA goals. PSE is modeling 80% renewable resources by 2030 and 100% by 2045 to meet the Washington Clean Energy Transformation Act (CETA). VPPs are a platform to find the best use of distributed energy resources (DER) on the grid and are included on PSE's grid modernization road map. PSE is evaluating distributed resources in the 2021 IRP.

Feedback Form Date	Stakeholder	Comment	PSE Response
8/15/2020	Jane Lindley, Act 4 Climate	Here is an example of a utility that is wise enough to plan for large increase of EV ownership: https://www.utilitydive.com/news/xcel-energy-unveils-plan-to-serve-15m-evs-by-2030/583428/ "Electric vehicles are the next frontier in the clean energy transition," Xcel Chairman and CEO Ben Fowke said in a statement. "We have substantial plans in place in the states we serve, and we can expand on this with partnership and support from policymakers, regulators, customers, automakers and our communities." The plan will result in $1 billion in annual customer fuel savings, through a mix of residential charging, increased access to public electric transportation and charging, and faster fleet electrification, according to the utility.	Thank you for providing information concerning EVs and Xcel Energy's promotion and support of EVs.
8/15/2020	Jane Lindley, Act 4 Climate	Along with helping to build EV infrastructure, I recommend that PSE seriously consider Vehicle-to-Grid technology, which will almost certainly become a large and inexpensive resource to store renewable energy as PSE strives to meet CETA goals by 2030 and 2045.	Thank you for your comment considering Vehicle-to-Grid technology.
8/17/2020	Anne Newcomb	I would like to compliment you on the great presentations you have put together and your clear and kind communications with us as Stakeholders. It is very exciting to see PSE moving to the clean energy future! It feels right to be working together on this very important project for the entire planet!	Thank you for sharing your positive impression of PSE's 2021 IRP process.
8/17/2020	Anne Newcomb	I like many others involved would like to see the variable social cost of carbon included. By this I mean having the cost reflected at the time of burned fossil fuels for electricity produced. I think this will help customers and regulators see a truer cost of burning fossil fuels than if the cost is included in the entire mix. If you could also add in the cost of clean up of ground water from Colstrip and any oil or gas spills or explosion clean up this would be helpful. I have heard PSE can get community pushback for Solar and Wind projects. Possibly by showing the true costs of fossil fuels to customers they will become more and more supportive of renewable energy in their communities. This could make PSE's renewable energy projects flow more easily. Thank you for including the ramp up of Solar projects on the Westside. By creating solar energy projects in public parks, homes and business roofs and grounds the energy can be produced near the end user reducing energy loss on transmission lines and hopefully reducing the amount of transmission lines needed. Incentives are very helpful! I bet County and State Parks would be interested in collaboration on solar and wind projects. I appreciated seeing your integrated grid model on page 42! It looks like with the help of many talented PSE employees, PSE is going to be on track to meet CETA's important CO'2 reduction goals!!! Thank You for your dedicated work on the most important PSE IRP yet! Keep up the great work!	Thank you for sharing your support for PSE examining the social cost of carbon as a variable cost and thoughts concerning capturing costs differently in the IRP concerning specific resource types. PSE includes costs associated with electric generating plants including capital costs, taxes, insurance, transmission, fixed operations & maintenance, variable operations & maintenance, fuel, and decommissioning costs. Thank you for sharing your appreciation for the presentation on DER Integration in the August 11 webinar. Thank you for sharing your positive impression of PSE's 2021 IRP process.
8/18/2020	Orijit Ghoshal, Invenergy	Attached are Invenergy's comments on the social cost of carbon as presented on August 11. [PSE inserted Overall Comment on Use of the Social Cost of Carbon] During Webinar 6 on August 11, 2020, Puget Sound Energy (PSE) did not adequately respond to or resolve the concerns expressed by Invenergy and other stakeholders about its preferred approach to including the Social Cost of Carbon (SCC) in its 2021 Integrated Resource Plan (IRP). Invenergy strongly encourages PSE to reconsider including the SCC as a fixed annual cost in the resource portfolio modeling for its 2021 IRP. Instead, PSE should treat the SCC as an incremental cost of hourly dispatch for Greenhouse Gas (GHG)-emitting resources. This approach will be more consistent with: a) the purpose and intent of the Clean Energy Transformation Act (CETA); b) accepted practices for internalizing the environmental externality costs of GHG emissions into decision making; and c) how the SCC was developed as an estimate of the economic value of environmental damages caused by GHG emissions and the intended use of the SCC. Before proceeding with the resource portfolio modeling sensitivity analyses, Invenergy strongly encourages PSE to address the issues surrounding properly including the SCC in its resource portfolio modeling analyses for the 2021 IRP.	Thank you for the attachment, your comments and questions. PSE has inserted the content of your letter directly in the form to facilitate our responses. The attachment you provided has also been uploaded as part of the Webinar 6 Feedback Form package on pse.com.

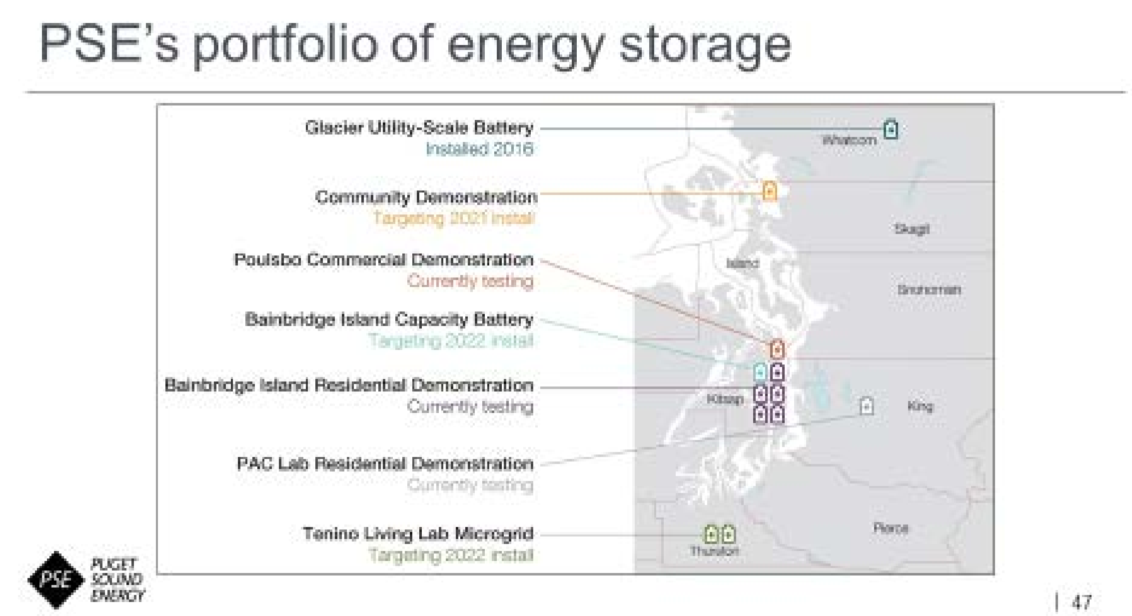
Feedback Form Date	Stakeholder	Comment	PSE Response
8/18/2020	Orijit Ghoshal, Invenergy	Incorporate the social cost of carbon into the incremental dispatch cost of all generators used to serve loads subject to CETA.	Thank you for your comment. As requested by Invenergy and other stakeholders, and discussed during the August 11 IRP meeting and in a prior meeting with Invenergy and other stakeholders, PSE has included a portfolio sensitivity that incorporates the social cost of carbon as a variable dispatch cost.
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 1] CETA imposes two distinct requirements for PSE to limit its GHG emissions. The first requirement is to limit its annual GHG emissions (i.e., 80 percent GHG-free by 2030 and 100 GHG-free by 2045). The second requirement is for PSE to incorporate the SCC into its resource planning and acquisition decisions.	PSE understand CETA requirements and agrees with Invenergy's statement. PSE is including the SCC in its resource planning and acquisition decisions. A portfolio sensitivity where SCC is included as a dispatch cost has been added to the list and a sensitivity where annual GHG emissions is limited has also been added to the list of portfolios to analyze.
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 2] Satisfying just one of these requirements does not relieve PSE of its obligation to satisfy the other requirement. Therefore, PSE needs to properly incorporate the SCC in its 2021 IRP.	Thank you for your concern about making sure PSE includes the SCC as part of the 2021 IRP. PSE is including the SCC in the decision to add new supply-side or demand side resources or to retire existing resources in the 2021 IRP. PSE plans to address both requirements through the 2021 IRP portfolio modeling.
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 3] GHG emissions are an environmental externality. They are a real cost to society that is caused by but not borne by PSE or its retail electric customers. As a result, GHG emissions and the environmental damages they cause represent a clear market failure. Until and unless a mechanism to solve this market failure (e.g., carbon tax or GHG cap and trade program) is implemented in Washington State, the best available means for dealing with this market failure is to treat GHG emissions as an environmental externality.	Thank you for your suggestion concerning a scenario where social cost of carbon is incorporated in the incremental dispatch cost of all generators used to serve loads. This has been added to the portfolio sensitivity list to be analyzed.
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 4] Instead of imposing a carbon tax or creating a GHG cap and trade program, it is quite clear that the intent of CETA is to treat GHG emissions as an environmental externality. While CETA does not explicitly use the terms "environmental externality" or "market failure", it recognizes and requires utilities to deal with GHG emissions as such. For example, Subsection 14(3)(a) of CETA states the following: An electric utility shall consider the social cost of greenhouse gas emissions, as determined by the commission for investor-owned utilities pursuant to section 15 of this act and the department for consumer-owned utilities, when developing integrated resource plans and clean energy action plans. An electric utility must incorporate the social cost of greenhouse gas emissions as a cost adder when: (i) Evaluating and selecting conservation policies, programs, and targets; (ii) Developing integrated resource plans and clean energy action plans; and (iii) Evaluating and selecting intermediate term and long-term resource options.	Thank you for your comment.
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 5] Further, Section 15 of CETA identifies the SCC as the required metric for treating GHG emissions as an environmental externality: *For the purposes of this act, the cost of greenhouse gas emissions resulting from the generation of electricity, including the effect of emissions, is equal to the cost per metric ton of carbon dioxide equivalent emissions, using the two and one-half percent 21 discount rate, listed in table 2, technical support document: Technical update of the social cost of carbon for regulatory impact analysis under Executive Order No. 12866, published by the interagency working group on social cost of greenhouse gases of the United States government, August 2016. The commission must adjust the costs established in this section to reflect the effect of inflation.*	Thank you for your comment.
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 6] The SCC was developed by the federal Interagency Working Group (IWG) as an economic estimate of the real, incremental environmental damage costs caused by the emission of one metric ton of CO2equivalent GHG emissions. The IWG specifically designed and developed the SCC to quantify the externality effects of GHG emissions and incorporate them into economic decisions.	Thank you for your comment.
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 7] Applying the SCC as an incremental cost is also consistent with well-established economic principles for incorporating environmental externalities into decision-making, including for integrated resource planning.	Thank you for your comment.
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 8] Environmental damages caused by GHG emissions are incremental costs; they are not fixed costs. Correspondingly, the SCC is an estimate of the incremental economic costs – not the fixed economic costs – of the environmental damages caused by GHG emissions.	Thank you for your comment.

Feedback Form Date	Stakeholder	Comment	PSE Response
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 9] While CETA requires PSE to use the SCC to represent the environmental damage costs caused by GHG emissions, it does not authorize PSE to include the damage costs in its revenue requirements or in its retail electric rates.	Thank you for your comment.
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 10] Therefore, PSE's analysis for its 2021 IRP needs to recognize the distinction between the two types of costs and account for them properly. Specifically, resource decisions should be made on the basis of the sum of revenue requirements costs plus environmental damage costs (as represented by the SCC). However, rate impacts of resource decisions should only include revenue requirements costs.	Thank you for your comment.
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 11] There is nothing in CETA that requires or justifies treating the SCC as a fixed annual cost.	Thank you for your comment.
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 12] Treating the SCC as a fixed annual cost biases resource decisions in favor of more GHG-intensive resources. A key reason for this is that excluding the SCC from simulation of hourly dispatching decisions in the portfolio modeling leads to increased generation by more GHG-intensive resources. In turn, this allows the fixed costs of the more GHG-intensive resources to be spread over a larger quantity of generation, thereby causing the total (revenue requirements and externality) costs of those resources to artificially appear lower than if the SCC were included in hourly dispatching decisions.	Thank you for your comment.
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 13] PSE has said its past analyses showed that including the SCC as a variable cost of dispatch did not materially change the mix of resources in its modeling results. Invenergy remains skeptical about the validity of this conclusion, including due to flaws in PSE's prior assumptions and methodology for incorporating the SCC. Further, if including the SCC as a variable cost of dispatch truly does not change PSE's resource decisions, then PSE should have no objection to using that method.	Thank you for your comments. As discussed during the August 11 webinar, PSE will conduct new analysis for the 2021 IRP to model the SCC as both the cost adder and a variable cost of dispatch.
8/18/2020	Orijit Ghoshal, Invenergy	[Specific comment 14] If PSE does not agree that the SCC should be properly modeled as an incremental cost of hourly dispatch, PSE should perform a fair and rigorous side-by-side analysis of PSE's preferred approach of treating the SCC as a fixed annual cost with the more sound approach of including the SCC as a variable hourly dispatch cost for existing and new GHG-emitting resources it would use to serve its retail customers' needs. PSE should complete the side-by-side analysis and obtain feedback on the results from stakeholders before proceeding with the numerous portfolio sensitivity analyses it is planning to perform.	Thank you for your comment.
8/18/2020	Katie Ware, Renewable Northwest	Please see attachment.	Thank you for your comments. As discussed during the August 11 webinar, PSE will conduct new analysis for the 2021 IRP to model the SCC as both the cost adder and a variable cost of dispatch. The side-by-side results will be shared during upcoming webinars and stakeholders will be able to review the results.
8/18/2020	Katie Ware, Renewable Northwest	1. Renewable Northwest appreciates PSE's request for stakeholder suggestions regarding the appropriate portfolio sensitivities PSE should model. Below are our recommendations: a. Regarding the renewable over-generation test, we recommend that PSE incorporate the effects of this sensitivity on the 2% cost threshold relevant to compliance with CETA standards. Specifically, should PSE choose to or be required to over-generate renewables to meet load, how early in a compliance period would PSE meet the 2% cost threshold, and thus be considered in compliance with the clean energy standards? b. Regarding the must-take DR and battery storage sensitivity, we again recommend that PSE incorporate the effects on the 2% cost threshold. We recommend that PSE consider this detail in modeling other sensitivities which may lead PSE to the cost cap early in each compliance period. c. Regarding the highly-centralized sensitivity within the Transmission Constraints and Build Limitations category, we recommend that PSE consider including additional constraints specific to renewable proxy locations, whereby a strict delivery requirement mandated by CETA may create geographic limitations to new-build renewables. d. Regarding the SCC as a tax in WA, OR and CA sensitivity, we agree with PSE that this tax should be modeled WECC-wide for consistency.	Thank you for your comments and questions. PSE responses referenced as "a – d": a. PSE plans to include renewables to meet CETA requirement and does not elect to over-generate renewables during planning. However, over-generation may occur during certain times of the year. It is important to understand the impact of over-generation without additional constraints. Including the 2% cost threshold may limit the addition of new resources and thus not meet CETA requirements. PSE plans to model the over-generation sensitivity without the 2% cost threshold. b. The description you provided is consistent with PSE's approach regarding the must-take DR and battery storage. c. PSE will be reaching out to you to clarify this suggestion. d. Thank you for expressing your support that SCC PSE that this tax should be modeled WECC. This will be noted in the updated spreadsheet file.

Feedback Form Date	Stakeholder	Comment	PSE Response
8/18/2020	Katie Ware, Renewable Northwest	2. Renewable Northwest supports PSE's approach to modeling the social cost of carbon (SCC) as a post-economic dispatch fixed cost adder. Our understanding aligns with what PSE has vocalized in multiple webinars, that an alternative methodology applying the SCC as a dispatch adder would artificially deflate the capacity factors of emitting resources, thus skewing the model's output.	Thank you for your feedback.
8/18/2020	Katie Ware, Renewable Northwest	3. Renewable Northwest appreciates PSE's consideration of stakeholder feedback in considering how to meet the 20% alternative compliance permitted by CETA's greenhouse-gas neutrality standard. While our preference is always going to be that PSE does not rely on alternative compliance, we recognize the utility in planning a gradual transition to 100% clean. That said, we would advise against relying on resource-based compliance payments, given the more climate-beneficial options granted by CETA. Unbundled RECs support renewable energy development, and Energy Transformation Projects (ETPs) aim to reduce the state's non-energy sector GHG emissions. Both of these options support system transformation and GHG-emission reductions, while penalties do not.	Thank you for your feedback. CETA alternative compliance will be further discussed in the September 1, 2020 webinar.
8/18/2020	Katie Ware, Renewable Northwest	Renewable Northwest thanks PSE for its consideration of this feedback. We look forward to continued engagement as a stakeholder in this 2021 IRP process.	PSE appreciates the involvement of Renewable Northwest! Thank you for your participation!
8/18/2020	Joni Bosh, NW Energy Coalition	See attached comments	Thank you for the attached letter directed to Elizabeth Hossner, Manager Resource Planning & Analysis, and your comments and questions. PSE has inserted the content of your letter directly in the form to facilitate our responses. The attachment you provided has also been uploaded as part of the Webinar 6 Feedback Form package on pse.com/irp.
8/18/2020	Joni Bosh, NW Energy Coalition	NW Energy Coalition (NWEC) appreciates the opportunity to ask questions about and make suggestions regarding Puget Sound Energy's (PSE's) proposed portfolio scenarios and sensitivities to address in analysis in the Integrated Resource Planning effort. Our comments focus on the excel slide presented in the webinar of July 11th that lists all the various scenarios that PSE might model, respond to PSE's question of how it should meet the 20% alternative compliance option offered in the Clean Energy Transformation Act (CETA), and on demand response.	PSE appreciates the involvement by NWEC and thank you for your input.
8/18/2020	Joni Bosh, NW Energy Coalition	The Social Cost of Carbon (SCC) represents the costs of environmental damages that society at large, not PSE customers, bears from GHG emissions. The SCC is an environmental externality which CETA requires be applied when making resource decisions to account for the effects of GHG emissions. As an externality, the SCC should be applied to dispatch of all resources both owned and acquired, and all market purchases (since the source cannot generally be known for market purchases), rather than applied as part of the fixed costs of capital assets. In neither case should the SCC be treated as part of the revenue requirement.	Thank you for your description concerning defining environmental externality in terms of relevant to the SCC.
8/18/2020	Joni Bosh, NW Energy Coalition	We would further clarify that the comment under "Notes" on scenario 19 on the excel sheet does not exactly capture what we are asking for – the SCC should be added at dispatch to all resources; adding the SCC as a separate cost to market purchases would be appropriate, as long as those added costs are not included in the revenue requirement. Therefore, we would change the Note on line 19 to: dispatch cost in LTCE only, SCC not included in electric price, BUT AS so a separate EXTERNAL COST adder included for TO ALL market purchases.	Thank you for the clarification.
8/18/2020	Joni Bosh, NW Energy Coalition	We would consider the options described on lines 35 and 36 as "bookends" for the initial analysis purposes.	Thank you for your comment.
8/18/2020	Joni Bosh, NW Energy Coalition	Slide 17 – NWEC would appreciate if the actual values that will be used in modeling are presented in the slide, rather than the descriptors "low", "mid" and "high".	Thank you for the suggestion PSE add more detail to the slides, specifically value ranges on Slide 17 of the August 11 presentation.
8/18/2020	Joni Bosh, NW Energy Coalition	Slide 26 - PSE will need to be very clear as to how the choices will be ranked or prioritized, so there are no unanticipated disappointments if some analyses are not completed.	The actual prioritization of the sensitivities by stakeholders will occur at the October 20, 2020 webinar. We are still thinking through the best way to do that and appreciate this comment.
8/18/2020	Joni Bosh, NW Energy Coalition	Slide 36 – requests feedback from stakeholders on prioritizing the four options that can be considered for alternative compliance. To be very clear, 19.405.040(1)(a)(ii) actually requires a utility to " use electricity from renewable resources and non-emitting electric generation in an amount equal to one hundred percent of the utility's retail electric loads over each multiyear compliance period", which would be the preferred compliance. But we recognize that 19.405.040(1)(b), which immediately follows, allows a utility to meet up to 20 percent of that obligation between 2030 and 2045 with alternative compliance options. Of the options available, the one that should not be evaluated is energy from MSW generators ("garbage burners"), which have yet to be proven to provide a net reduction in GHG emissions.	To clarify, PSE is modeling 100% of the utility's retail electric loads over each multiyear compliance period as a sensitivity. There will be opportunity to additional stakeholder feedback at the October 20, 2020 webinar. PSE agrees with NWEC; PSE will not be evaluating the MSW generators ("garbage burners") in the 2021 IRP.

Feedback Form Date	Stakeholder	Comment	PSE Response
8/18/2020	Joni Bosh, NW Energy Coalition	NWEC proposes the following additional sensitivities: • Advanced Demand Response, based on the Northwest Power and Conservation Council draft inputs, including resource potential and cost by DR type, for the 2021 Northwest Power Plan, adjusted as appropriate for the mix of customer classes and uses in PSE's service territory. This will help provide an estimate of the potential to address PSE's capacity needs as the resource mix changes in the coming decade and beyond. • Updated Upstream Methane Factor, using the EDF Low upstream emissions factor of 2.47% as documented in the NW Council's workshop that we forwarded as part of the IRP comment process. NWEC requested this sensitivity during the August 11 workshop but it is not reflected in the updated version of the summary spreadsheet. We recommend running this sensitivity using scenario #1, mid economic conditions, and substituting the 2.47% upstream methane emissions factor. This will provide a bookend sensitivity on upstream emissions and the social cost of carbon for PSE's resource portfolio and market purchases. • High Electric Vehicle Saturation, using an appropriate scale-up factor such as 50% higher than the forecast estimate for 2025, adjusted appropriately thereafter. We recommend two versions of this sensitivity, one assuming no load shaping and the other assuming some combination of rate design and incentives to shape demand away from system peak. The purpose of this sensitivity is to assess the impact of faster EV saturation on overall resource needs and specifically on daily and seasonal peak impact.	Thank you for providing your additional sensitivities requests. They have been added to the list. PSE is still considering the modeling options related to the upstream emissions and will provide additional information in the consultation update on September 1, 2020. PSE will be asking stakeholders prioritize the sensitivities during the October 20 IRP meeting. At this part of the process, stakeholders will have access to the draft portfolio results to better inform their selections. Stakeholders will provide valuable feedback as to how PSE can best prioritize sensitivity analyses.
8/18/2020	Kyle Frankiewich, WUTC Staff	Slide 11: I'm still struggling some with the difference between a scenario and a sensitivity. It seems to me that some single-input changes, which could be called a sensitivity, could change the company's electric price forecast. It would be nice if it was possible to freeze the electric price forecast, and then compare various tweaks to the models and see how PSE might respond to that forecast, but if a sensitivity is likely to impact the forecast, then the comparison becomes difficult.	Scenarios are different sets of assumptions that create future power market conditions. These assumptions include: - Gas prices, carbon regulation, and regional loads that create different wholesale market power prices, which affect the relative value of different resources. - Wholesale price forecasts developed using the AURORA model. - Other major generators in the Western U.S., as well as loads from those areas. Portfolio sensitivities are minor changes to a scenarios set of assumptions that create alternate portfolios of supply and demand side generation for PSE. - A scenario must be selected to change in order to perform a sensitivity analysis. - Typically, a single variable or single set of assumptions is changed in order to isolate the effect of that change on the scenario. - The results of a sensitivity can be compared to the base scenario, or other sensitivities that are based on the same scenario. The electric price forecast is an input to the IRP model. PSE runs different scenarios to create different electric price forecasts to test with PSE's portfolio. PSE will reach out to you to discuss this further.
8/18/2020	Kyle Frankiewich, WUTC Staff	Slide 15: Economic conditions are perhaps the biggest assumptions in the portfolio, and have become very difficult to vet given the pandemic and apparent recession. How will PSE's scenarios and sensitivities give the company a good view of the relative value of different resource decisions in a volatile environment? Is there a tipping point for economic indicators that would prompt PSE to either use the inputs representing low economic conditions for various sensitivities? o In general, how, if at all, does the IRP modeling process inform which indicators the utility monitors to inform adaptive management practices?	Concerning how the IRP modeling process informs which indicators the utility monitors to inform adaptive management practices, PSE applies adaptive management practices through our corporate governance processes. For example, the demand forecast is approved by an executive oversight group prior to sharing with stakeholders. For the IRP, PSE runs a stochastic analysis that varies different economic conditions such as demand forecast, gas prices and electric price forecasts.

Feedback Form Date	Stakeholder	Comment	PSE Response
8/18/2020	Kyle Frankiewich, WUTC Staff	Slide 19: What does the over-generation sensitivity represent? Is this the removal of a modeling constraint that prevents overgeneration?	During the 2019 IRP process, PSE evaluated modeling results and found that there were hours where renewable generation was being sold into the market but the energy was still being counted towards meeting the renewable requirement. This test is isolates PSE as a system to prevent the renewable energy from being sold, forcing it to be curtailed or stored instead.
8/18/2020	Kyle Frankiewich, WUTC Staff	Slide 20: What decision point does sensitivity 13 analyze? It seems that the trapped energy issue explored here might be better understood through a stochastic analysis using PSE's granular historical data for wind and solar resources in WA. There also may be some Tx paths or renewable generation profiles that are complement each other such that 'overbuilding' relative to available Tx is more reasonable in some regions than it is in others. Is this nuance explored within sensitivity 13? Relatedly, do the transmission constraint sensitivities effectively model minimum in-state builds?	Concerning the first question, yes, PSE will be getting to the trapped energy issue in sensitivity 13. This sensitivity evaluates buying less than nameplate firm transmission and evaluating the risk if non-firm transmission can be purchased for the energy over transmission limit or if the energy will get curtailed. Concerning 'overbuilding' or complimentary renewable generation, this is addressed in the baseline assumptions with dual purpose transmission.
8/18/2020	Kyle Frankiewich, WUTC Staff	Slide 21: What NEIs are included in sensitivity 16? I understand that the CPA provided some NEIs on a measure-by-measure basis. I'd like to better understand this and verify that there's no double-counting here, and that NEIs are appropriately included in the baseline model run. Relatedly, the company has previously mentioned that early runs show the cost-effective conservation selection are pretty far up the conservation curve. Where specifically? In the company's current runs, what is the $/MWh delta between where the marginally cost-effective bundle and the next available conservation bundle that was marginally not cost-effective?	PSE will provide additional information in the consultation update available on September 1, 2020.
8/18/2020	Kyle Frankiewich, WUTC Staff	Slide 24: It seems that sensitivity 26 includes two different constraints – no new gas, and 100% renewable by 2030. I have no problem with these constraints as a modeling exercise, but would appreciate some clarification. Are these separate constraints? Or does no new gas lead to 100% renewable by 2030 for some reason?	Sensitivity #26 models 100% renewable generation by 2030. We understand your confusion and will change the description to say "100% renewable resources by 2030, no gas generation" in the updated excel file.
8/18/2020	Kyle Frankiewich, WUTC Staff	Slides 29-36 were skipped. I hope we get a chance to discuss these, as I think stakeholder feedback on how to contemplate Energy Transformation Projects in the IRP would be useful.	Thank you for your comment. Slides 29-36 will be presented at the September 1 webinar. Concerning how PSE will contemplate Energy Transformation Projects, this is an IRP result, and will be presented later in the process and be included in the final 2021 IRP.
8/18/2020	Kyle Frankiewich, WUTC Staff	Slides 47-48: These projects are exciting. Other utilities, such as Green Mountain Power, PGE and a number of California IOUs, are even further down this road. Is PSE going to extrapolate from current demonstrations and projects from other utilities to develop cost and resource size estimates appropriate to PSE's service territory? Will these resources be selectable within PSE's modeling tools?	For the 2021 IRP modeling process, PSE plans to use the generic resource cost discussed during the 2021 IRP webinar 1 held on May 28, 2020. Stakeholders reviewed those costs and provided feedback, which was summarized in the feedback report and consultation update available on our website. The IRP process will select generic storage resources, which could be delivered through many different program designs. PSE's own demonstration work, and our regular discussions with other utilities, form a basis for what will actually be implemented in future programs and the associated values from that implementation.

Feedback Form Date	Stakeholder	Comment	PSE Response
			
8/18/2020	Kyle Frankiewich, WUTC Staff	Slide 54: How soon will these forecasting and hosting capacity capabilities be available? Will this granularity prompt a revisit of the system-wide T&D deferral estimates?	PSE will be addressing these questions in the consultation update on September 1, 2020.
8/18/2020	Kyle Frankiewich, WUTC Staff	Slide 54: How does PSE anticipate the geospatial analysis will inform the utility's compliance with CETA's requirement to equitably distribute energy- and non-energy benefits?	PSE will be addressing these questions in the consultation update on September 1, 2020.
8/18/2020	Kyle Frankiewich, WUTC Staff	Slides 57-58: I understood the company's explanation of the must-take solar and batteries as an inclusion of PSE's acquisition of these resources not for whole-system need, but as cost-competitive alternatives to other distribution-level system projects. Is this correct? This seems reasonable, but more information would be useful – info on historical acquisition rates for these types of NWAs, and on the company's forecasted future acquisitions. Are the ~160 MW of cumulative resources shown in slide 57 *all* included as must-take?	PSE will be addressing these questions in the consultation update on September 1, 2020.
8/18/2020	Kyle Frankiewich, WUTC Staff	[Recommendation 1:] Clarity on baseline to sensitivities: The IRP participants discussed many requests that would alter the assumptions that are nailed down in the baseline. I'm using the word 'baseline' to mean the best approximation at a business-as-usual forecast with middle-of-the-road inputs across the board. I encourage the company to spend some time going over what inputs are included in this baseline run, as, if I understand correctly, all sensitivities and some scenarios will be compared to this.	Thank you for your feedback. PSE will include a full description in the IRP book and discuss the baseline assumptions in more detail at the October 20 webinar.
8/18/2020	Kyle Frankiewich, WUTC Staff	[Recommendation 2:] Sensitivity and scenario requests: I've tried to pull together staff requests made thus far in the process. I've compiled these in the attached Excel spreadsheet. Staff appreciates that many of our requests have been included in the 31 sensitivities listed by PSE.	Thank you for the attached Excel spreadsheet and the additional sensitivity requests. The file you provided have been uploaded as part of the Webinar 6 Feedback Form package on pse.com.
8/18/2020	Kyle Frankiewich, WUTC Staff	[Recommendation 3:] SCC as fixed-cost adder vs in dispatch: Staff is still at the learning stages in vetting this modeling decision. I understand that previous analysis has shown that the RPS component of CETA carries the most weight in determining PSE's future resource needs. I hope the company does a similar comparison in this cycle. Accepting the	Thank you for your feedback. PSE will include an SCC only sensitivity on the list and will run the analysis to test how the portfolio builds change with SCC as a fixed-cost adder vs a dispatch cost. This can be found as sensitivity 38 in the updated sensitivity spreadsheet.

Feedback Form Date	Stakeholder	Comment	PSE Response
		premise that, over the long term, the RPS is the main constraint guiding PSE's resource acquisitions, I still think this may be relevant with regard to gauge near-term cost-effectiveness for conservation, demand response, and distributed energy resources. I am also interested in Participant Gutman-Britten's proposal to run this side-by-side without the RPS constraint, which will give us a view into whether the optimized portfolio changes dramatically based on this modeling decision.	
8/18/2020	Kyle Frankiewich, WUTC Staff	[Recommendation 4:] Federal CO2 tax: I echo other stakeholders in recommending that the federal carbon tax modeled in sensitivity 22 be structured to align with bills being proposed in Congress.	Thank you for your feedback. This support is noted in the updated sensitivity spreadsheet.
8/18/2020	Kyle Frankiewich, WUTC Staff	[Recommendation 5:] Upstream emissions and NWPCC: I haven't verified this, but I understand that the Northwest Power and Conservation Council intends to model upstream emissions on natural gas in their next power plan. I have heard that their estimate is about 1.37% leakage. How does this compare to the estimates PSE intends to use? How does this compare with other published studies exploring this issue, such as the 2018 EDF assessment? Do the NWPCC's approach and assumptions align with PSE's (EPA and Canadian province govt estimates, if I recall)? To the extent PSE's modeling of this issue diverges from the Council's, I'd like to fully understand why.	PSE will be addressing these questions in the consultation update on September 1, 2020.
8/18/2020	Kyle Frankiewich, WUTC Staff	[Recommendation 6:] Climate change and weather data inputs: This issue may be more appropriate in the stochastic modeling and resource adequacy portion of the IRP process, but I wanted to flag this as an area of interest for staff. My core concern is whether PSE's preferred resource portfolio performs great under historical weather and water inputs, but poorly under weather inputs adjusted to account for climate change. PSE's planning efforts should contemplate this risk. Perhaps this could be part of a scenario tree as in slide 15, or perhaps we can see what we learn from scenario 31; we're open to discussion on how best to address this. Relatedly, is PSE's Itron Study re: Climate Change complete? If so, please provide a copy of the study and findings; please provide a rough timeframe if not.	Thank you for your feedback. PSE shares your concerns and plans to use the temperature sensitivity as well as the high and low demand forecasts and the stochastic analysis to inform the resource plan. PSE's load forecast is based on a normal weather assumption of heating degree days (HDD) and cooling degree days (CDD) calculated using hourly temperatures measured at the NOAA SeaTac weather station. This normal assumption is constant throughout the forecast period. Itron will construct trended HDDs and CDDs that reflect historical temperature trends at the SeaTac weather station. Steps include: 1. Itron will evaluate average and peak-producing temperature trends. Itron will evaluate the following concepts: • Average annual temperature • Maximum annual temperature • Minimum annual temperature 2. From the analysis in step 1, Itron will construct a trended normal daily temperature series, and trended normal daily and monthly HDD and CDD that may be used by PSE's current set of load forecast models. Results will be delivered to PSE in an Excel spreadsheet. 3. Itron will produce a report documenting the methodology and the results of the temperature trend analysis. The draft report is expected by early October.

PSE IRP Feedback Report Addendum
Webinar 6: Portfolio Sensitivities
August 11, 2020

9/01/2020

The following stakeholder input was gathered through the online Feedback Form, from August 4 through August 18, 2020. PSE was unable to gather the responses in time for the August 25, 2020 Feedback Form. This report addendum is a response to the items not included in the August 25, 2020. The responses were published on September 1, 2020 and referenced in the Consultation Update.

Feedback Form Date	Stakeholder	Comment	PSE Response
8/18/2020	Katie Ware, Renewable Northwest	1. Renewable Northwest appreciates PSE's request for stakeholder suggestions regarding the appropriate portfolio sensitivities PSE should model. Below are our recommendations: a. Regarding the renewable over-generation test, we recommend that PSE incorporate the effects of this sensitivity on the 2% cost threshold relevant to compliance with CETA standards. Specifically, should PSE choose to or be required to over-generate renewables to meet load, how early in a compliance period would PSE meet the 2% cost threshold, and thus be considered in compliance with the clean energy standards? b. Regarding the must-take DR and battery storage sensitivity, we again recommend that PSE incorporate the effects on the 2% cost threshold. We recommend that PSE consider this detail in modeling other sensitivities which may lead PSE to the cost cap early in each compliance period. c. Regarding the highly-centralized sensitivity within the Transmission Constraints and Build Limitations category, we recommend that PSE consider including additional constraints specific to renewable proxy locations, whereby a strict delivery requirement mandated by CETA may create geographic limitations to new-build renewables. d. Regarding the SCC as a tax in WA, OR and CA sensitivity, we agree with PSE that this tax should be modeled WECC-wide for consistency.	Thank you for your comments and questions. PSE responses referenced as "a – d": a. PSE plans to include renewable resources to meet CETA requirement and does not elect to over-generate renewable resources during planning. However, over-generation may occur during certain times of the year. It is important to understand the impact of over-generation without additional constraints. Including the 2% cost threshold may limit the addition of new resources and thus not meet CETA requirements. PSE plans to model the over-generation sensitivity without the 2% cost threshold. b. The description you provided is consistent with PSE's approach regarding the must-take DR and battery storage. c. <u>Update for September 1</u>: PSE reached out to Katie Ware on 08/27 and the clarification will be made well before the October 20 IRP meeting. d. Thank you for expressing your support for implementing the SCC as a WECC-wide tax. This will be noted in the updated spreadsheet file.
8/18/2020	Kyle Frankiewich, WUTC Staff	Slide 11: I'm still struggling some with the difference between a scenario and a sensitivity. It seems to me that some single-input changes, which could be called a sensitivity, could change the company's electric price forecast. It would be nice if it was possible to freeze the electric price forecast, and then compare various tweaks to the models and see how PSE might respond to that forecast, but if a sensitivity is likely to impact the forecast, then the comparison becomes difficult.	Scenarios are different sets of assumptions that create future power market conditions. These assumptions include: - Gas prices, carbon regulation, and regional loads that create different wholesale market power prices, which affect the relative value of different resources. - Wholesale price forecasts developed using the AURORA model. - Other major generators in the Western U.S., as well as loads from those areas. Portfolio sensitivities are minor changes to a scenario that creates alternate portfolios of supply and demand side resources for PSE. - A scenario must be selected to change in order to perform a sensitivity analysis. - Typically, a single variable or single set of assumptions is changed in order to isolate the effect of that change on the scenario. - The results of a sensitivity can be compared to the chosen scenario, or other sensitivities that are based on the same scenario. The electric price forecast is an input to the IRP model. PSE runs different scenarios to create different electric price forecasts to test with PSE's portfolio. PSE will reach out to you to discuss this further. <u>Update for September 1</u>: PSE discussed this with Kyle on 08/27/2020.

Feedback Form Date	Stakeholder	Comment	PSE Response
8/18/2020	Kyle Frankiewich, WUTC Staff	Slide 21: What NEIs are included in sensitivity 16? I understand that the CPA provided some NEIs on a measure-by-measure basis. I'd like to better understand this and verify that there's no double-counting here, and that NEIs are appropriately included in the baseline model run. Relatedly, the company has previously mentioned that early runs show the cost-effective conservation selection are pretty far up the conservation curve. Where specifically? In the company's current runs, what is the $/MWh delta between where the marginally cost-effective bundle and the next available conservation bundle that was marginally not cost-effective?	PSE will use the EPA study suggested by NWEC for the sensitivity that accounts for the health benefits of conservation. There will be no overlap with the NEIs that are currently in the CPA as they not related to the health benefits addressed by the study. More data will be available regarding the supply curve once the portfolio analyses are complete.
8/18/2020	Kyle Frankiewich, WUTC Staff	Slide 54: How soon will these forecasting and hosting capacity capabilities be available? Will this granularity prompt a revisit of the system-wide T&D deferral estimates?	PSE expects to implement geospatial load forecasting in 2021. Hosting capacity analysis methods are currently being researched and requirements for those tools are in development. The requirements of the selected tool will drive the implementation schedule, but implementation of HCA is expected by 2022. Full capability will not be realized until the completion of AMI implementation in 2023. Geospatial load forecasting and HCA would not trigger a revisit of the system-wide T&D deferral estimate. Additional analysis would be required to determine if adjusting the T&D deferral value was warranted.
8/18/2020	Kyle Frankiewich, WUTC Staff	Slide 54: How does PSE anticipate the geospatial analysis will inform the utility's compliance with CETA's requirement to equitably distribute energy- and non-energy benefits?	PSE anticipates that demand side management and customer DER program participation will be modeled in the geospatial load forecast. Equity and accessibility in program design will be reflected in the forecast, and will drive electric system investments accordingly.
8/18/2020	Kyle Frankiewich, WUTC Staff	Slides 57-58: I understood the company's explanation of the must-take solar and batteries as an inclusion of PSE's acquisition of these resources not for whole-system need, but as cost-competitive alternatives to other distribution-level system projects. Is this correct? This seems reasonable, but more information would be useful – info on historical acquisition rates for these types of NWAs, and on the company's forecasted future acquisitions. Are the ~160 MW of cumulative resources shown in slide 57 *all* included as must-take?	Yes, that is correct. As presented in the table on Slide 58, must-take solar and batteries as an inclusion of PSE's acquisition of these resources not for whole-system need, but as cost-competitive alternatives to other distribution-level system projects. As presented in the table on Slide 58, must-take solar and batteries are included as cost-competitive alternatives to other distribution-level system projects. Concerning your suggestion for additional information: PSE's work regarding NWAs began in 2018/2019 and is growing. To date, one area's concerns are economically solved by NWA (Bainbridge Island). More area studies on this process are underway to determine solution viability. The NWA forecast as shown on slide 57 was developed from comparing the known concerns against characteristics that were proven by the Bainbridge Island solution. More detailed studies will be performed to sharpen this forecast over time. The forecast basis for storage and targeted EE/DR are based on both the Bainbridge Island and Lynden NWA study results, while the PV projection is based on current industry knowledge. The forecast will become more accurate as we complete more studies. This forecast includes Non-wire alternatives to solve localized capacity needs. Correct, the ~160 MW of cumulative resources shown in slide 57 *all* are included as must-take.
8/18/2020	Kyle Frankiewich, WUTC Staff	[Recommendation 5:] Upstream emissions and NWPCC: I haven't verified this, but I understand that the Northwest Power and Conservation Council intends to model upstream emissions on natural gas in their next power plan. I have heard that their estimate is about 1.37% leakage. How does this compare to the estimates PSE intends to use? How does this compare with other published studies exploring this issue, such as the 2018 EDF assessment? Do the NWPCC's approach and assumptions align with PSE's (EPA and Canadian province govt estimates, if I recall)? To the extent PSE's modeling of this issue diverges from the Council's, I'd like to fully understand why.	PSE reached out to Kyle on 08/27 to discuss this and there will be additional follow-up.

PSE IRP Consultation Update
Webinar 6: Portfolio Sensitivities
August 11, 2020

09/01/2020

The following consultation update is the result of stakeholder suggestions gathered through the IRP online Feedback Form, collected between August 4 through August 18 and summarized in the August 25, 2020 Feedback Report. The report themes have been summarized along with responses to the suggestions that have been implemented. If a suggestion was not implemented, the reason is provided.

PSE thanks Kyle Frankiewich (WUTC Staff) for follow-up discussions concerning his questions on August 27, 2020.

PSE thanks Katie Ware (Renewable Northwest) for being available for a clarification call concerning her suggestion for a sensitivity; a call will be arranged well before the October 20 IRP Meeting.

Certain responses were not included in the August 25, 2020 Feedback Report. Those questions have been addressed in the Webinar 6 Feedback Form Addendum, also dated and uploaded to pse.com on September 1, 2020.

Feedback Report Addendum

The feedback received from Kyle Frankiewich (WUTC Staff) regarding non-energy benfits on slide 21, questions regarding slide 54, and questions on slides 57-58 on distributed solar and batteries was not answered in the Feedback Report posted on August 25, so an addendum to answer the questions has been posted.

Summary of Stakeholder Feedback on Portfolio Sensitivities

PSE appreciates the feedback provided by stakeholders. In summary, the following list of sensitivities has been added to the list:

Portfolio sensitivities added during the August 11 webinar:

1. Social cost of carbon only (as a planning adder), no CETA renewable requirement
2. Social cost of carbon only (as a dispatch cost), no CETA renewable requirement
3. Add 185 MW to MT transmission from Colstrip transmission line
4. Fuel switching from electric to gas
5. High economic conditions with SCC as a dispatch cost in the portfolio model only
6. Electric vehicle battery to grid available as a distributed energy resource
7. Time of use pricing for conservation and demand response
8. Wholistic conservation approach

Portfolio sensitivities added from the feedback report for the August 11 webinar:

9. Municipal bans on new natural gas
10. Refinements to resource cost assumptions
11. Private solar input testing
12. Equity focused portfolio
13. 2% Cost threshold
14. 2% Cost threshold - Must take DR and Battery storage first, then optimize other builds
15. 2% Cost threshold - Renewable Overgeneration Test
16. Virtual Power Plants (VPP)
17. Hydrogen as an alternative fuel for NG plants

Notes received from stakeholders regarding sensitivities already on the list:

Sensitivity #22 - Mid economic conditions with SCC as a fixed cost plus a federal CO_2 tax
Virginia Lohr suggested to use a higher cost than $15, more consistent with proposed federal legislation

Sensitivity #31 - Temperature sensitivity on load
Don Marsh suggested to use most recent 10-15 years of temperature data to capture recent trends

PSE will make best efforts to complete as many portfolio sensitivities as possible for the 2021 IRP. However, given that the list has over 50 different portfolio sensitivities, PSE will ask stakeholders to prioritize the list. PSE will begin with the analysis with portfolios 1-3 (Mid, Low, and High economic conditions). The draft portfolios will be presented at the October 14 meeting for natural gas and the October 20 meeting for electricity. Once the stakeholders have an opportunity to view the draft results, PSE will will re-evaluate the list of sensitivities with the stakehodlers, then prioritize list of portfolio sensitivities.

PSE is committed to keeping our stakeholders informed of our progress toward incorportating feedback into the 2021 IRP process.

Update on the Electric Price Forecast - follow-up from June 10 Webinar as referenced in the August 11 Webinar 6 and related updates

On June 10, 2020, PSE presented the draft electric price forecast and incorporated stakeholder feedback regarding the electric price forecast.

1. Regional Demand Forecast

PSE received feedback from James Adcock, Kathi Scanlan (WUTC Staff), and Joni Bosh and Fred Heutte (NWEC), concerning PSE's use of the Northwest Power and Conservation Council's (the Council) 7th Power Plan regional demand forecast.

> **PSE response**: PSE contacted the Council and included the demand forecast from the 2019 Policy Update to the 2018 Wholesale Electricity Forecast, which is the latest available demand forecast.

2. Washington Renewable Need

PSE received feedback from Vlad Gutman-Britten (Climate Solutions) and James Adcock regarding the starting point for the renewable ramp used for meeting the Washington state CETA requirements.

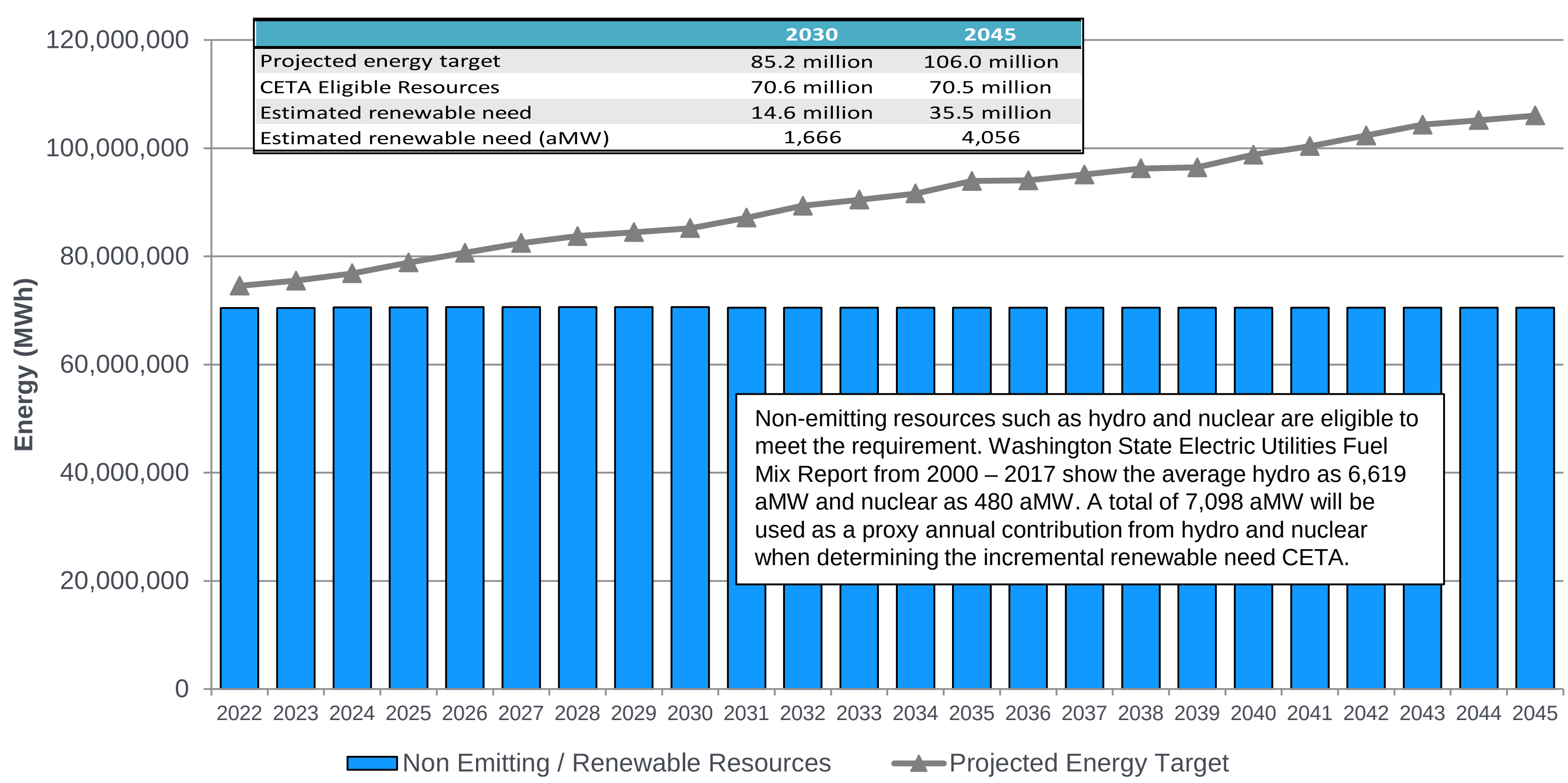
> **PSE response**: PSE updated the Washington renewable need for the updated demand forecast and started the ramp in 2022.

3. Natural Gas Price Forecast

PSE received feedback from Kathi Scanlan (WUTC Staff), requesting the use of an updated gas price forecast to reflect the socioeconomic changes of the COVID-19 pandemic.

> **PSE response**: PSE updated to the most recent natural gas price forecast from Wood Mackenzie.

The final electric price forecast was presented at the August 21 webinar as an update for stakeholders. James Adcock requested to see the updated Washington renewable need chart used for the electric price forecast during the webinar. PSE replied that it will be included in the constulation update for the webinar. The chart below is the renewable need for Washington state (MWh).



Webinar #7: CETA Assumptions, Demand Forecast, Resource Adequacy, Resource Need Q&A

9/2/2020

Overview

On September 1, 2020 Puget Sound Energy hosted an online meeting with stakeholders to discuss CETA assumptions, demand forecast, resource adequacy and resource need. Additionally, participants were able to ask questions and make comments using a chat box provided by the Go2Meeting platform.

Below is a report of the questions submitted to the chat box. Answers to the questions were provided verbally by IRP staff during the webinar. Please note that questions were answered in order of relevance to the topic currently being discussed. Questions regarding other topics were answered at the end of the webinar session.

To view a recording of the webinar and to hear responses from staff, please visit the project website at pse-irp.participate.online.

Attendees

A total of 70 stakeholders and PSE staff attended the webinar, plus another 11 attendees who called into the meeting and did not identify themselves (81 people total).

Attendees included: Allison Jacobs, Anne Newcomb, Anthony O’Rourke, Benjamin Zwirek, Bill Pascoe, Brian Grunkemeyer, Charlie Inman, Cody Duncan, Court Olson, Dan Kirschner, Don Marsh, Elyette Weinstein, Fred Heutte, Graham Horn, James Adcock, Jenny Lybeck, Jim Heidell, Jon Howell, Joni Bosh, Julie Zuckerman, Katie Ware, Kevin Jones, Kevin Yates, Kyle Frankiewich, Lana Gonoratsky, Larry Becker, Lori Elworth, Mike Hopkins, Natalie Mims, Nick Abrams, Nick Bengtson, Norm Hansen, Orijit Ghoshal, Patrick Leslie, Rachel Brombaugh, Rahul Venkatesh, Robert Briggs, Sarah Laycock, Stephanie Chase, Steve Johnson, Ted Drennan, Virginia Lohr, Vlad Gutman-Britten, Warren Halverson, Weimin Dang, Willard Westre

Questions Received

Questions from attendees are posted in the order in which they were received. The webinar began at 1:00 PM PDT and ended at 4:11 PM PDT.

Name	Time Sent	Comment
James Adcock	**1:07 PM**	Hand Raise Slide 10
James Adcock	**1:09 PM**	Hand Raise Slide 13
Kyle Frankiewich	**1:14 PM**	Hello all! Apologies for joining late; had some internet troubles at home.
Joni Bosh	**1:15 PM**	Since Ecology has not finished the rule making around what kinds of projects qualify as ETPs,
Alexandra Streamer	**1:15 PM**	@Kyle, no problem – thanks for joining us!
Don Marsh	**1:20 PM**	We would like to see more forecasts for those "pockets" of demand, since PSE develops responses for those pockets. This seems like a blind spot in the IRP process.
Alexandra Streamer	**1:23 PM**	Thanks for the comment, Don
Don Marsh	**1:26 PM**	Raise hand slide 23
Anne Newcomb	**1:37 PM**	Thank you for including Covid impacts. How is PSE effected by the current and in many cases the future work from home ethic and less building occupation?
Warren Halverson	**1:41 PM**	PSE has actual demand data from Mar-Se', 6 months, please share with us the quantitative change and that actual percent impact for the next few years.
Warren Halverson	**1:41 PM**	Thank you.
Anne Newcomb	**1:44 PM**	Thanks for the great answer!
Warren Halverson	**1:47 PM**	Thank you
Don Marsh	**1:48 PM**	Raise hand slide 28
Vlad Gutman-Britten	**1:52 PM**	Do you consider the impact of ETPs on this EV deployment?
Kyle Frankiewich	**1:53 PM**	agree that it's reasonable to expect some interactive effects between EVSE-based ETPs and EV adoption
Anne Newcomb	**1:54 PM**	Well said Don! :-)
Natalie Mims	**1:54 PM**	1:54 PM: Could you (repeat) the assumptions about on-peak and off-peak charging (e.g., 100% of charging is on-peak, 50% is on-peak)?
Fred Heutte	**1:54 PM**	I'm curious about the eventual saturation of EVs at about 25% by 2050. PGE also had analysis from Navigant and estimated a mid-range of 35% by 2050, with a low estimate about half that, and a high estimate more than double. Is PSE also including a low and high estimate in the IRP modeling?
Brian Grunkemeyer	**1:54 PM**	I'd like to suggest a CETA Energy Transformation Project. I think EV charging can be used to help further your carbon reduction goals. Looks like we can reduce emissions by about 10% using Don's suggestion of a fixed TOU, but we have some preliminary data suggesting a 20% reduction in emissions using a marginal CO2 emissions forecast. Would PSE consider something like this?
Bill Pascoe	**1:55 PM**	Raise Hand #28
Kyle Frankiewich	**1:56 PM**	ETP = Energy Transformation Projects
Anne Newcomb	**1:58 PM**	Has peak demand changed during the pandemic?

Don Marsh	**2:02 PM**	Raise hand slide 29
Fred Heutte	**2:03 PM**	Comment on slide 29.
Virginia Lohr	**2:04 PM**	Looking at new forecasts related to Covid and making immediate changes to your demand forecasts for the future is impressive. Projecting accurately what will happen in the future is essential for an IRP to be valid, so your making such rapid adjustment for Covid is noteworthy For temperature data, I see only backward looking data. The proposed scenarios look at using different segments of historic data, but none of the proposals are future looking. Clearly, you found projections on the impact of covid, and projections of changes of future temperatures could be found. We know that getting good projections for future temperatures is essential to getting useful projections for the environment in which PSE will be operating. Your President has said "I have been a very vocal advocate of the need to combat climate change however we can." Please help me understand the rationale for treating temperature data so differently from all the other forecasts, such as electric vehicle use, and how this will help your
Alexandra Streamer	**2:05 PM**	@Virginia thanks for your question – looks like it may have been cut off at the end.
Don Marsh	**2:07 PM**	Thanks, Elisabeth!
Fred Heutte	**2:08 PM**	Here's the NW Council staff's most recent summary of the climate-adjusted load forecast inputs for the 2021 Northwest Plan. Extensive presentations on how climate modeling has been incorporated into their estimates can also be found on their site: **https://www.nwcouncil.org/sites/default/files/2020_08_p3.pdf**
James Adcock	**2:08 PM**	I suggest that everyone should be less worried about average Heating Degree Days, or Cooling Degree Days, and instead worry more about how Puget is modeling Peak Capacity needs aka "Coldest Winter Day" assumptions for "Resource Adequacy" purposes -- because I think Puget may be high by about 700 Megawatts.
Virginia Lohr	**2:17 PM**	Looking at forecasts related to Covid & making changes to your demand forecasts is impressive. Projecting the future accurately is essential for an IRP to be valid, so your making such rapid adjustment for Covid is noteworthy. For temperature data, I see only backward looking data. The proposed scenarios use different segments of historic data, but none of the proposals are future looking. You found projections on the impact of covid, and projections of changes of future temperatures could be found. Getting good projections for future temperatures is essential to getting useful projections for the environment in which PSE will be operating. Your President said "I have been a very vocal advocate of the need to combat climate change however we can." Please help me understand the rationale for treating temperature so differently from all the other IRP forecasts, and how this will help your President show us that she intends for PSE to combat climate change if temperature forecasts are not used in this IRP.
Anne Newcomb	**2:17 PM**	Does PSE have any new NG fired turbines under construction or any NG Gas plants in the pipeline currently or are there any future plans to add NG facilities?

Don Marsh	**2:22 PM**	Raise hand slide 32
Kyle Frankiewich	**2:26 PM**	Agree that 2019 post-DSR lines provide really useful context
Court Olson	**2:33 PM**	I second the comments that Don Marsh is making on the gas demand projection chart.
Don Marsh	**2:40 PM**	Raise hand
Anne Newcomb	**2:42 PM**	Good answer. Thanks!
Court Olson	**2:42 PM**	Good to see no peak load growth over the next 12 to 15 years with the anticipated conservation. I think that trend is likely to continue beyond that time frame.
Court Olson	**2:44 PM**	FYI, recent modeling by the State of Washington predicts that Summer Peak will be bigger than winter peak by 2050. PSE should be predicting such a change.
Fred Heutte	**2:46 PM**	Comment on summer peak: the issue is not so much that it is lower than winter, but that the market is limited and will be moreso in the future with coal retirements.
Kyle Frankiewich	**2:48 PM**	+1 for Fred's comment. Even if PSE's load isn't as big in July as it is in December, it may still be a bigger challenge to meet that load, or may have to pay exorbitant prices in competition with OR and CA to do so.
Kevin Jones	**2:49 PM**	Please don't overlook Anne Newcomb's question at 2:17
Steve Johnson	**2:50 PM**	From 2017 IRP page E-6 showing regression variables states $\chi 1=$ dummy variables used to put special emphasis on summer months to reflect growing summer peaks.
Brian Grunkemeyer	**2:50 PM**	To augment Kyle's comment - An easy way to proivde more context would be to see what the BPA and other utilities are doing with power sales during the summer vs. winter. If all available power is being sold to California in the summer, the power available in the NW may be quite limited. (No need to discuss, but please consider offline.)
Fred Heutte	**2:53 PM**	Slide 55 – a comment.
James Adcock	**2:53 PM**	To augment Brian's comments about BPA -- BPA has a legal requirement to meet the needs of the PNW before sales to other regions -- such as California. I don't believe BPA would want to be in the position of selling to California during a power shortage in the PNW -- I think that action would prove to be very troublesome for BPA to defend.
Kevin Jones	**3:05 PM**	raise hand
Brian Grunkemeyer	**3:06 PM**	Elizabeth, can you please confirm that your RA work looks at market availability of power during the summer, in addition to winter?
Fred Heutte	**3:07 PM**	Just to point out BPA must first meet the needs of its preference customers (public power), then offer any remaining resource within the Northwest ("regional preference") and only then sell outside the region.
Brian Grunkemeyer	**3:08 PM**	.. So essentially, if we have a Northwest-wide spike in demand, PSE may still not be able to get power during a summer. PSE's summer peak may of course be lower, but if they are still short in the summer during a peak demand period, PSE could need to curtail load. Correct?
James Adcock	**3:10 PM**	Raise Hand Slide 63

Don Marsh	**3:11 PM**	+ 1 on Brian's comment. I just looked up Avista's 2021 IRP. That utility is showing historical peaks and forecasts for both summer and winter. PSE shouldn't hide the summer peak forecast.
Don Marsh	**3:11 PM**	Raise hand slide 63
Willard Westre	**3:13 PM**	Raise Hand s-66 & 67
Kyle Frankiewich	**3:18 PM**	**Raised hand**
Fred Heutte	**3:21 PM**	question on slide 65
James Adcock	**3:27 PM**	Re Slide 63 it would also be good to know that the "Hydro Data" has actually been "corrected" to reflect BPA change in operational conditions back in th 1980s -- a question which Puget hasn't clearly answered yet (and these issues have been unresolved for more than a decade now.)
Brian Grunkemeyer	**3:27 PM**	Kyle, great question. Would probably have a higher LOLP in summer, and lower in winter. But these numbers are computed on an annual basis. It's tricky. But this is important to avoid a California-style power shortage.
James Adcock	**3:39 PM**	It is also important to not build emitting resources in excess of what is in-practice needed on a 20-year basis.
James Adcock	**3:30 PM**	There has been about one day of largish Mid-C price spikes per year the last couple of years.
Brian Grunkemeyer	**3:31 PM**	You've just put your finger on the tension here. We want a lower LOLP to ensure PSE doesn't over-build based on the winter peak. We want a carefully-computed LOLP that might be higher in the summer to ensure we don't have a California-style blackout. This is a tricky tension, and the UTC has to make sure they can understand and defend this process to a future governor if something goes wrong.
James Adcock	**3:33 PM**	It is not UTC's job to defend Puget's choices right or wrong. It is Puget's job to defend Puget's choices right or wrong. And they can be wrong in two different directions -- they can "model" their peak capacity needs too high, or too low.
Brian Grunkemeyer	**3:34 PM**	What should PSE do? Two versions of the RA model, take the max of two LOLP's?
James Adcock	**3:35 PM**	In practice I suggest Puget should limit themselves to the most recent 30 years of temperature data. And they need to make sure that their hydro data has actually been "corrected" to account for BPA changes in operational practices as-of in 1980s.
Don Marsh	**3:37 PM**	Agreed. 30 years for RAM, 20 years for normal temperature calculation for peaks.
Court Olson	**3:37 PM**	These charts don't have significant value without DSR included.
Fred Heutte	**3:38 PM**	responding to Brian: as Tom Eckman from the NW Council liked to say, "you always want to be a little 'long' but not too long!"
Anne Newcomb	**3:39 PM**	It looks like my question will be better on slide 72. I see you are having a fresh look at your 2018 RFP which had a peaker plant Does PSE have any new NG fired turbines under construction or any NG Gas plants in the pipeline currently or are there any future plans to add NG facilities?
Virginia Lohr	**3:40 PM**	That question was from Anne. That was not my question.
James Adcock	**3:40 PM**	Renewables fuels are only allowed to the extent that they are fed directly to the NG power plant.

Virginia Lohr	**3:41 PM**	Please askmy question.
Anne Newcomb	**3:41 PM**	No problem at all! Thanks!
Don Marsh	**3:41 PM**	Raise hand
James Adcock	**3:42 PM**	Raise hand
Court Olson	**3:42 PM**	I didn't hear an answer to Anne's question on future PSE plans to build gas facilities. It was sidestepped.
Fred Heutte	**3:42 PM**	comment in response to Don Marsh

PSE IRP Feedback Report
Webinar 7: CETA Assumptions, Demand Forecast, Resource Adequacy, Resource Need
September 1, 2020

9/15/2020

The following stakeholder input was gathered through the online Feedback Form, from August 25 through September 8, 2020. PSE's response to the feedback can be found in the far-right column. To understand how PSE incorporated this feedback into the 2021 IRP, read the Consultation Update, which will be released on September 22, 2020.

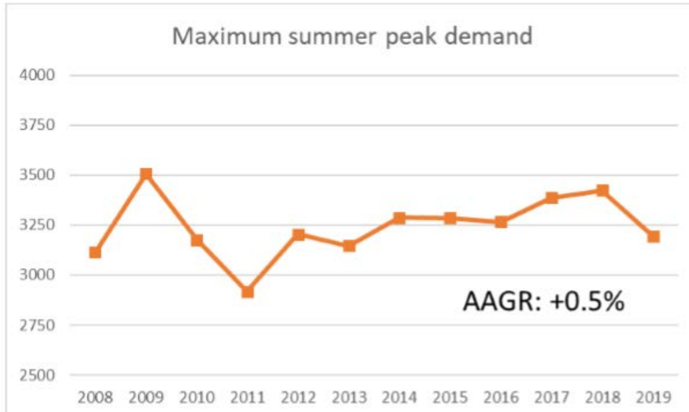
<table>
<tr><th>Feedback Form Date</th><th>Stakeholder</th><th>Comment</th><th>PSE Response</th></tr>
<tr><td>8/27/20</td><td>Mike Hopkins, Fortis BC</td><td>I was wondering if the peak electric load forecast on slide 28 includes any programs/initiatives/rates, such as time-of-use or EV charging rates, that would reduce the impacts of EV home charging on peak loads by shifting charging to off-peak times? If yes, how much is the peak load reduced vs. without these things? if no, are you planning to include them or include a qualitative discussion of what they might be able to do in terms of shifting peak charging?</td><td>The peak loads associated with EVs do not include assumptions for specific future programs, initiatives, or rates. In this IRP, PSE is modeling several demand response programs including commercial and industrial (C&I) critical peak pricing (CPP) and EV charging:
<table>
<tr><th>Product</th><th>Group</th><th>Number of Events</th><th>Notification Type</th></tr>
<tr><td>C&I CPP-No Enablement</td><td>Commercial Critical Peak Pricing</td><td>Up to ten 4-hour events</td><td>Day-ahead (non-dispatchable)</td></tr>
<tr><td>C&I CPP-With Enablement</td><td>Commercial Critical Peak Pricing</td><td>Up to ten 4-hour events</td><td>Day-ahead</td></tr>
<tr><td>Res Electric Vehicle DLC</td><td>Residential Electric Vehicles</td><td>Up to ten 4-hour events</td><td>Day-ahead</td></tr>
</table>
The IRP modeling process will determine how much peak load may be reduced by these types of demand response programs.

Additionally, going forward in future IRPs, assumptions about EV demand response program design and peak load reduction will be based on experience gained through the Up & Go Pilot Program, which PSE is currently running.</td></tr>
<tr><td>[sent by email 08/22/20]</td><td>Don Marsh, CENSE</td><td>Don provided a two-page letter directed to Irena Netik and IRP staff with questions for the September 1 webinar.</td><td>Thank you for providing questions prior to the meeting. Your questions informed the meeting content. Questions 1 through 10 were addressed during the webinar. Question 11 is addressed below. The letter, dated July 22, 2020, is uploaded as part of the Feedback Report.</td></tr>
<tr><td>[sent by email 08/22/20]</td><td>Don Marsh, CENSE</td><td>Explain any significant differences between PSE's demand forecast and those of nearby utilities such as Seattle City Light, Snohomish PUD, Tacoma Power, PacifiCorp, Avista, and Portland General Electric. What regional factors may cause PSE's forecast to diverge from other utilities?</td><td>PSE expects load forecasts to differ among regional utilities due to various reasons, including:

Differences in type of service area. Utilities with primarily urban service areas have different opportunities for growth than do utilities with service areas that include suburban and/or rural areas. Additionally, whether customers have access to natural gas service affects trends in electric consumption.
Difference in composition of customer class mix. Trends in growth and usage differ among the residential, commercial, and industrial classes.
Climate. A utility that is primarily peaking due to heating load will have different consumption trends than a utility that serves both heating and cooling load equally.
</td></tr>
<tr><td>8/28/20</td><td>Don Marsh, CENSE</td><td>Attached is a two-page letter with feedback on the electric demand forecast. This will also be sent to UTC staff by email. This letter contains several requests for corrections and more transparent data.</td><td>The letter, dated July 22, 2020 and received on August 28, 2020, is uploaded as part of the Feedback Report and the material content provided below.</td></tr>
<tr><td>8/28/20</td><td>Don Marsh, CENSE</td><td>After reviewing the presentation for the upcoming (Sept. 1) IRP webinar to review PSE's latest load forecast, I would like to thank the team for some positive steps in this forecast:

1. The declining post-DSR electric forecast is more inline with forecasts for other nearby utilities (Seattle City Light, Tacoma</td><td>Thank you for this positive comment concerning improvements to PSE's IRP process.</td></tr>
</table>

Feedback Form Date	Stakeholder	Comment	PSE Response
		Power, Snohomish PUD). For example, PSE's forecast shows a -0.4% AAGR for 2021-2031. For comparison, Seattle City Light's 2018 IRP shows an AAGR of -0.6% for the same period. We are pleased to see the post-DSR estimate on the same graph as forecast growth pre-DSR. 2. PSE includes summer and winter peak demand data for 2008-2019 (slides 48 and 49), and a reference to the data source from the FERC library. This data clarifies historical trends. 3. In response to our queries about weather records and the basis of weather normalization, PSE published a table on slide 29 showing different durations for calculating normal weather. It is obvious that heating declines with shorter history periods (probably due to local climate change), and cooling increases. PSE's chosen standard is for a 30-year period, which appears to overstate heating and understate cooling.	
8/28/20	Don Marsh, CENSE	[Opportunity for improvement 1] The AAGR shown in the post-DSR electric forecast appears misleading without further context. The expected demand declines until 2031, and then starts to increase, leading to an overall AAGR of 0.2%. But the increases and the AAGR may be illusory because PSE is not accounting for any new conservation programs after 2031. The graph says, "No new conservation after committed 2-year targets," but this does not clarify that the increasing demand after 2031 is an accounting artifact, not a realistic possibility. If anything, more aggressive conservation will be necessary after 2031 to reach 100% clean energy by 2045 in accordance with CETA goals. This graph is specifically extended to 2046 to account for CETA, but the load forecast itself doesn't appear to account for the effects of CETA.	Positive customer growth, steady use per customer, and electric vehicles yield demand growth before demand side resources (DSR) are included. Applying DSR will result in an "after DSR" forecast with lower growth than "before DSR." The final amount of DSR will be determined by the portfolio model. The portfolio model results are forthcoming in the current IRP process and are yet to be determined. The "after DSR" results presented during the webinar are for illustrative purposes only and is based on DSR amounts determined by the 2019 IRP process. The final "after DSR" demand forecast will be available once the economic DSR amount is determined. The Clean Energy Transformation Act (CETA) affects the amount of demand-side resources. Demand-side resources are included as a resource option in the IRP portfolio model and are not included in the "before DSR" base demand forecast. The demand forecast from 2022 through 2045 is used as an input into the portfolio modeling, which is the purpose of showing the forecast through 2045 even though the forecast "before DSR" does not account for CETA.
8/28/20	Don Marsh, CENSE	[Opportunity for improvement 2] Although PSE included a table showing historical summer peak demand, the presentation includes no forecast for summer peaks. It doesn't even include a graph of historical summer peak demand, so I created the graph from PSE's data [see Don's letter OR Michele to insert picture]:	The IRP analysis optimizes generation resources to meet the maximum capacity need. For PSE the customer load has historically peaked in the winter. However, PSE will consider providing stakeholders the historical and forecasted electric summer peak information.

Feedback Form Date	Stakeholder	Comment	PSE Response
		 The graph shows a very gradual rise in summer peak demand, averaging about 0.5% per year. The peak in 2018 was almost as high as the highest peak in 2009, although the peak temperature in 2018 was eight degrees cooler, so it appears that peaks are gradually increasing.	
8/28/20	Don Marsh, CENSE	[Opportunity for improvement 3] We are puzzled why PSE is issuing RFPs for winter demand response, but no corresponding RFP for summer demand response. Summer peaks are increasing, and winter peaks are not. Obviously, the summer peaks are about 25% lower than winter peaks, but we understand that PSE is concerned about summer reliability. Does PSE believe that summer demand response is not needed or not as feasible as winter demand response?	The RFP is targeting specific areas that have a winter morning peak capacity need. Future RFPs will have different objectives.
8/28/20	Don Marsh, CENSE	[Opportunity for improvement 4] Using 30 years of weather records to normalize weather calculations is at the upper limit of what we consider reasonable, given recent changes in climate. As we observed in earlier letters, New York's utility commission is using 15 years of weather records for normalization.	The effects of warming temperature trends on the demand forecast will be analyzed as a sensitivity and has been added to list of portfolio sensitivities.
8/28/20	Don Marsh, CENSE	[Opportunity for improvement 5] On slide 63, PSE appears to be using "88 temperature years" as an input to the Resource Adequacy Model. This may distort the results and introduce "cold bias" in the model that could be potentially costly for ratepayers. We ask that no record before 1990 be used to better account for recent climate changes.	The effects of warming temperature trends on the demand forecast will be analyzed as a sensitivity and has been added to list of portfolio sensitivities.
8/28/20	Don Marsh, CENSE	[Closing suggestion] Declining winter peaks and gradually increasing summer peaks provide PSE and ratepayers some room to concentrate on CETA goals and smart energy management. However, clear data is needed to understand the challenges and opportunities before us. We encourage PSE to provide this data and strong leadership to achieve successful outcomes.	Thank you for your comment.

Feedback Form Date	Stakeholder	Comment	PSE Response
9/2/20	James Adcock	I am concerned that Elizabeth Hossner keeps saying that the EPA somehow is responsible for "RECs" -- vetting them, defining them, etc. I have diligently searched the EPA website and find nowhere any indication that these statements are true. On the contrary, RECs seem to be defined, tracked, and retired by various regional authorities, and the process of "vetting" RECs appears to be done by independent third parties. I ask that Puget and Elizabeth Hossner please double-check and update their understanding of RECs and how they work -- and why they are not "available" on a nationwide-basis, but only within a region. And please communicate this corrected understanding to IRP participants once you have done so, because I am afraid your comments are confusing participants. See for example, the REC registration organization for the Western region: https://www.wecc.org/WREGIS/Pages/Default.aspx	RECs are a nation-wide program and can be sold nation-wide. There is a national REC market for voluntary REC purchases (for corporations/entities wanting to voluntarily buy RECs). For compliance purposes, there are many regional markets across the nation and PSE participates in the WECC region. Eligible RECs for the WA Renewable Portfolio Standard (RPS) have to meet certain requirements outlined in RCW 19.285 and 194-37 WAC, one of which states that the generation source be located in the Pacific Northwest. Therefore there is a WA RPS Compliant regional market. The Washington Clean Energy Transformation Act (CETA) does not have a geographic restriction. WREGIS is the tracking system for purposes of verification of RECs under RCW 19.285. WREGIS certifies RECs for the WECC region for the Energy Independence Act (EIA), RCW 19.285. This information is available to all stakeholders. All feedback forms and consultation updates are available on pse.com/irp.
9/2/20	James Adcock	I ask that Puget and Elizabeth Hossner please double-check and update their understanding of RECs and how they work -- and why they are not available on a nationwide-basis, but only within a region. And please communicate this corrected understanding to IRP participants once you have done so, because I am afraid your comments are confusing participants.	The response is provided above.
9/2/20	Don Marsh, CENSE	After participating in yesterday's Demand Forecast webinar for PSE's 2021 IRP, a number of stakeholders were dismayed that PSE refused our requests to include a forecast of peak summer demand. The attached letter shows that Avista is supplying this information in its 2021 IRP. The convergence of winter and summer forecasts in Avista's service area may justify concern by PSE's customers as well. If summer demand is actually growing in PSE's service area, perhaps greater investment in solar panels and energy storage would be a cost-effective solution. Without good data about these trends, it is difficult to tell.	The letter, dated September 2, 2020, is uploaded as part of the Feedback Report. Your questions and PSE's responses are provided below. The IRP analysis optimizes generation resources to meet the maximum capacity need. For PSE the customer load has historically peaked in the winter. However, PSE is evaluating your request and will respond in the Consultation Update.
9/2/20	Don Marsh, CENSE	Please share PSE's summer peak demand forecast with normal weather based on 15-20 years of historic data.	The IRP analysis optimizes generation resources to meet the maximum capacity need. For PSE the customer load has historically peaked in the winter. However, PSE is evaluating your request and will respond in the Consultation Update. The normal weather assumption for PSE's demand forecast is based on the most recent 30 years of weather data. PSE has added a temperature sensitivity to the list of portfolio sensitivities.
9/8/20	Joni Bosh, NW Energy Coalition	See attached comments	The comments have been uploaded as part of the Feedback Report and the material content provided below for PSE's response.

Feedback Form Date	Stakeholder	Comment	PSE Response
9/8/20	Joni Bosh, NW Energy Coalition	In response to the question posed on prioritizing options for the 20% alternative compliance actions that might be addressed in the 2021 IRP, NWEC would urge PSE to model an aggressive amount of conservation and demand response. Beyond the required conservation and demand response required in sections .040 and .050 of CETA, additional innovative conservation, efficiency, storage and demand response should be considered for Energy Transformation Projects. Exploring those has the double impact of further reducing/managing load and achieving additional GHG reductions.	Thank you for your feedback, PSE will add a sensitivity to increase conservation and demand response as part of the alternative compliance options to the list of portfolio sensitivities.
9/8/20	Joni Bosh, NW Energy Coalition	Regarding the two charts on pages 24 and 38 of the presentation, it would be helpful to have more discussion on the impact of a couple of assumptions: 1. How would demand look in both the short and long run if there is a second or even third wave of coronavirus infections? 2. How does the current economic demographic model on slide 24 link with the demand forecast by the mid-2020s on slide 38? Is most of the lower peak attributable to lower per customer usage? –	Thank you for your two questions on pages 24 and 38 of the September 1, 2020 webinar. PSE's responses are provided below: 1. The base demand forecast includes assumptions about the pandemic, based on Moody's May 2020 economic outlook assumptions. The base demand forecast assumes that new infections begin to abate in July 2020 and there is no second wave of infections. PSE has not developed a demand forecast specifically for alternative pandemic scenarios. As part of regular IRP practice, in addition to the base demand forecast, a low and high demand forecast will be developed. The low demand forecast could be used as a proxy for a more severe pandemic scenario. 2. The employment forecast presented on slide 24 is an element of the customer growth and usage forecast, with employment levels appearing mostly in non-residential modelling. The 2020 slowdown impacts the demand forecast through lower usage in the short term and lasting "lost" customer additions in the medium and long term. However, separate from downstream impacts resulting from the economic contraction, other modelling updates yielded lower projections of non-residential customer growth and usage as well. The lower IRP peak demand after 2025 is a mix of several things: inclusion of 2020/2021 conservation targets not included in the 2019 IRP process, lower customer usage projections (particularly non-residential), and lower customer growth (which includes the lagged economic effects presented on slide 24).
9/8/20	Joni Bosh, NW Energy Coalition	We would strongly encourage using a 15-year historical base for heating and cooling day analysis instead of the 30-year base, as the data on slide 29 certainly supports that approach. Assuming "average weather" is probably acceptable for the energy forecast, if PSE uses the shorter time period of 15 years, as the shorter time period incorporates actual, real climate change impacts. Using the 15 year historical base could well modify the forecast peak trends.	PSE has added a temperature sensitivity to the list of portfolio sensitivities.
9/8/20	Robert Briggs, Vashon Climate Action Group	Given the strong correlation between PSE's electric load and outdoor temperature, I'm surprised PSE has not tapped into regional expertise in climate modeling to inform the IRP process. During the webinar, much discussion centered around what length of historic weather data should be used in load forecasting. PSE uses economic and other types of forecasting in projecting future loads. Why not do the same for climate, which impacts temperature-driven space-conditioning loads and water availability for hydro? World-class capabilities in regional climate modeling can be found at the University of Washington's Climate Impacts Group [https://cig.uw.edu/] and at Pacific Northwest National Laboratory's Atmospheric Sciences and Global Change Division [https://www.pnnl.gov/atmospheric/]. During the webinar, one of the presenters suggested that PSE's winter electric peak was typically about one gigawatt	Thank you for your comments and suggestions. PSE has added a temperature sensitivity to the list of portfolio sensitivities.

Feedback Form Date	Stakeholder	Comment	PSE Response
		higher than its summer peak. This could change very rapidly given the rate at which heat records are being broken in many parts of the world. The Pacific Northwest is particularly at risk of rapid, unprecedented growth in summer electric peaks, because residential buildings have not traditionally needed air-conditioning. For example, if 250,000 residences in the Pacific Northwest added central air-conditioning drawing 4 kW each, an additional GW of summer demand could appear very quickly. Heat and smoke from wild fires are making natural ventilation untenable. PSE needs to be planning for both summer and winter peaks and to be employing best available science to project how weather conditions will be changing in the future.	

PSE IRP Consultation Update
Webinar 7: Demand Forecast, Resource Adequacy & Resource Need
September 1, 2020

9/22/2020

The following consultation update is the result of stakeholder suggestions gathered through an online Feedback Form, collected between August 25 through September 8, 2020 and summarized in the August 15, 2020 Feedback Report. The report themes have been summarized and along with a response to the suggestions that have been implemented. If a suggestion was not implemented, the reason is provided.

Alternative compliance actions

PSE received feedback from Joni Bosh of Northwest Energy Coalition (NWEC) concerning increased use of conservation and demand response programs to meet the 20% alternative compliance metric as stated in CETA. PSE will add a sensitivity on increased conservation and demand response programs for the 2021 IRP.

PSE summer load forecast

PSE received feedback from Don Marsh of CENSE and Robert Briggs of Vashon Climate Action Group concerning PSE's summer load forecast. PSE is working on pulling the data together and a graphic of the 2021 IRP peak for both the summer and winter seasons. This graphic will be will be included in the IRP draft available on pse.irp/com to be submitted January 4, 2021 and/or the final IRP available on pse.com/irp to be filed with the WUTC on April 1, 2021. PSE realizes that its status as a winter peaking utility is relatively unique in the WECC region, and therefore performs all resource adequacy calculations for the entire year to take into consideration impacts of other regions on market conditions.

Temperature years

PSE received feedback from Don Marsh of CENSE, Joni Bosh of NWEC and Robert Briggs of Vashon Climate Action Group concerning the number of years of temperature data used to generate load forecasts and perform resource adequacy calculations. PSE would like to clarify that the temperature data used in these two aspects of IRP modeling are distinct, serve different purposes and, therefore, should not be indiscriminately grouped together.

Temperature data for the load forecasting purposes is used to understand and project climate trends over the modeling horizon. To address the impact of temperature data on the load forecast PSE will analyze a sensitivity on temperature and the demand forecast, as compared to the 30-year average normal used in the presented load forecast.

Temperature data for the resource adequacy model (RAM) is used to generate simulations over a range of conditions which could plausibly occur in the PSE service territory. The RAM requires many, many simulations to ensure statistically significant results in modeling highly stochastic processes. Therefore, the number of temperature years of data must be large enough to cover the range of temperature conditions likely to occur in the PSE service territory and generate enough simulations for accurate results. PSE currently uses 88 temperature years of data for the RAM model. PSE is researching peak temperatures and extreme weather conditions as part of the temperature sensitivity.

Washington Utilities and Transportation Commission feedback

Commission Staff provided feedback for the Webinar #7: Scenarios and Sensitivities on September 10. Due to the missed deadline, PSE is addressing the questions submitted on September 10 in this Consultation Update. The feedback, questions and comments from the WUTC concerning the Webinar #7 are presented below, followed by the PSE responses:

WUTC Staff: Slide 12: I'm curious about whether PSE is assessing CETA alternative compliance payments as a route to CETA compliance on a least-cost basis. Are the alternative compliance payments included as something like resource options in the portfolio expansion model? How is PSE modeling the various options – RECs, energy transformation projects, alternative compliance payments and additional generation?

PSE response: PSE plans to model a price forecast as a stand in for CETA alternative compliance unbundled RECs or Energy transformation projects. Some options can be either a CO_2 price forecast such as the California price or a REC price. PSE is seeking stakeholder feedback on the price forecast as the stand-in cost.

WUTC Staff: Slide 17: What goes into PSE's decision to change IAP2 participation levels from topic to topic? If stakeholders see potential problems with the information presented by PSE during an "INFORM" topic, is the company still open to receiving feedback?

PSE response: PSE determined the International Association for Public Participation (IAP2) participation level to the level on the spectrum PSE can commit to in the 2021 IRP process. The measure of success for IAP2 is not the level one chooses on the spectrum, but the level that can be achieved by PSE and the level PSE can maintain our promise to stakeholders. PSE greatly appreciates the feedback and participation of our stakeholders. For example, "INFORM" topics, PSE provides opportunities for questions and comments in the chat feature of GoToMeeting, during the meeting, as well as answering questions in the feedback report and addressing any follow-up in the consultation update.

WUTC Staff: Slide 27: It seems difficult to guess at whether some COVID-prompted energy usage shifts may persist, but it also seems unlikely that the post-COVID normal will be identical to the pre-COVID normal. Does PSE intend to adjust its long term energy usage pattern estimates based on a pre- and post-COVID analysis?

PSE response: PSE agrees that the COVID-19 pandemic event is significant and there is potential for a "new normal" regarding energy usage patterns. At this time, PSE has not yet observed what could be considered long-term usage pattern differences due to the pandemic. Once PSE determines that there has been a permanent shift in usage patterns, PSE will incorporate those into the forecast.

WUTC Staff: Slide 29: The table shows that a shorter timeframe for defining 'normal' has an outsized impact on cooling estimates. Warmer and dryer summers may not yet have an impact on PSE's resource adequacy in the summer months, but could have a dramatic impact on the price of electricity. PSE discussed the RA component of its market reliance in this presentation, but did not cover the cost risk. How is that represented in the IRP? Does the IRP consider the prospect of escalating costs for market power as summers get hotter, and as thermal generators retire?

PSE responses:
To date concerning the modeling, no loss of load events occurs in the summer months in the Resource Adequacy Model (RAM). RAM only evaluates the capacity need with the balance between the supply and demand; cost is not included.

The cost risk of market reliance be will addressed in PSE's stochastic modeling. PSE is still working on the cost risk around market reliance and the stochastic model will be presented at the December 9, 2020 IRP meeting.

WUTC Staff: Slide 60: Is GENESYS and the WPCM both run 7040 times, once for each RAM run?

PSE response: Yes, GENSYS and WPCM both consider the 88 temperature years and 80 hydro years, so there are 7040 simulations (88 x 80 = 7,040) in total.

WUTC Staff: Slide 61: Please refresh my memory about the COB import limit. What is the nature of the 3400 MW limit? Are there any plans to increase (or decrease) this limit? Also, how are connections to other regions – BC to NW, MT to NW, SW (AZ/NV/CA) to NW – modeled?

PSE response: Regional interties are part of the regional GENESYS model and PSE relies on the Northwest Power and Conservation Council's assumption of 3400 MW limit. PSE then interconnects to the regional model with the 1500 MW limit to the Mid-C market.

WUTC Staff: Slide 63: What does temperature do in the RA model? Does temperature impact load or thermal performance?

PSE response: RAM considers 88 temperature years in the load forecast. Thermal plant outages are modeled in AURORA using the Frequency Duration. This takes into account the forced outage rate (%) and mean time to repair (hours). The outages are model for each generating unit individually with a probability of failure (FOR) and run for 260 different simulations of outages. The probability of an outage is not based on temperature.

WUTC Staff: Slide 63 (cont): What data does GENESYS need? Is that data provided in the software? Can it be modified? Can it be made publicly available?

PSE response: GENESYS uses the data from the Northwest Power and Conservation Council (NPCC), which is publicly available. The PNW regional generation and load forecast data relevant for the years 2022-2045 is publicly available. For the study years 2027 and 2031, PSE considers the load growth and retirements of units, which is obtained from NPCC staff.

WUTC Staff: Slide 63 (cont): What new resources are included as inputs into the RAM?

PSE response: In 2021 IRP, PSE will include the new resources and contracts obtained through the 2018 RFP.

WUTC Staff: Please provide some examples what is meant by "regional curtailment" and explain how these affect a model run.

PSE response: With the expected load growth and generation retirements, the capacity of supply will be, at times, less than the demand. That is the physical meaning of load curtailment. For example, during a peak hour, the regional resource capacity is 3000 MW but the regional load is 3001 MW, then a regional load curtailment occurs. During a PNW load curtailment event, there is not enough physical power supply available in the region, including available imports from California, for all of the region's utilities to meet their loads plus operating reserves. The Wholesale Purchase Curtailment Model (WPCM) will "allocate" the regional capacity deficiency to the individual utilities. These individual capacity shortages are reflected through a reduction in the forecasted level of wholesale market purchases. On an hourly basis, the WPCM translates a regional load-curtailment event into a reduction in PSE's wholesale market purchases.

WUTC Staff: Slide 71: What other contracts are expiring in 2026 and 2027 to cause the contraction of the "Contract" portion of the bars representing those years?

PSE response: Please see below table.

Resource (Contract)	Nameplate (MW)	Contract End Date
Twin Falls	20	3/8/2025
Centralia PPA	380[1]	12/31/2025
Colstrip 3 & 4	370[2]	12/31/2025
Electron	24	12/31/2026
2018 RFP new contracts	200	12/31/2026

NOTES

1. *The capacity of the TransAlta Centralia PPA is designed to ramp up over time to help meet PSE's resource needs. According to the contract, PSE will receive 280 MW from 12/1/2015 to 11/30/2016, 380 MW from 12/1/2016 to 12/31/2024 and 300 MW from 1/1/2025 to 12/31/2025.*
2. *Does not include the sale of unit 4.*

For the 2021 IRP, all contracts are expected to retire on the contract expiration date except for the Mid-C hydro contracts. In light of meeting the requirements of CETA, PSE assumes an extension of the Mid-C contracts and uses the current share as proxy to the extension. Terms and/or the possibility a contract extension will be determined closer to the actual expiration of the contracts.

WUTC Staff: Slide 71: Do PSE's existing hydro contracts include some contract mechanism that ensures PSE can obtain a renewal of the contracts as represented starting in 2028? Or is the company presuming that, whatever the negotiated cost ends up being, it's safe to assume that PSE will renew?

PSE response:

For the 2021 IRP, all contracts are expected to retire on the contract expiration date except for the Mid-C hydro contracts. In light of meeting the requirements of CETA, PSE assumes an extension of the Mid-C contracts and uses the current share as proxy to the extension. Terms and/or the possibility a contract extension will be determined closer to the actual expiration of the contracts.

Summary of all updates

PSE appreciates the feedback provided by stakeholders. In summary, the following changes will be implemented into the portfolio model or included in the proposed portfolio sensitivities:

- An increased conservation and demand response program sensitivity will be analyzed to explore the impact of using these measures to meet the CETA alternative compliance metrics.
- Summer peak demand forecasts will be included in IRP documentation as reference material.
- A temperature sensitivity will be analyzed which examines the impact to the demand forecast.

PSE is committed to keeping our stakeholders informed of our progress toward incorporating feedback into the 2021 IRP process.

Webinar #8: Natural Gas IRP

10/15/2020

Overview

On October 14, 2020 Puget Sound Energy hosted an online meeting with stakeholders to discuss the Natural Gas IRP. Additionally, participants were able to ask questions and make comments using a chat box provided by the Go2Meeting platform.

Below is a report of the questions submitted to the chat box. Answers to the questions were provided verbally by IRP staff during the webinar. Please note that questions were answered in order of relevance to the topic currently being discussed. Questions regarding other topics were answered at the end of the webinar session.

To view a recording of the webinar and to hear responses from staff, please visit the project website at pse-irp.participate.online. The recording for this webinar has been uploaded as two separate files. On the day of the webinar, the start of the meeting through Slide 20 was not initially recorded. To correct this error, PSE and EnviroIssues re-recorded this section on October 15, asked and answered all the questions asked from stakeholders the day before.

Attendees

A total of 48 stakeholders and PSE staff attended the webinar, plus another 3 attendees who called into the meeting and did not identify themselves (51 people total).

Attendees included: Allison Jacobs, Anne Newcomb, Ben Farrow, Bob Stolaski, Brian Grunkemeyer, Charlie Inman, Christine Bunch, Cody Duncan, Court Olson, Dan Kirschner, David Perk, David Tomlinson, Deborah Reynolds, Don Marsh, Elyette Weinstein, Fred Heutte, James Adcock, Josh Rubenstein, Kara Durbin, Kassie Markos, Kathi Scanlan, Larry Becker, Leanne Guier, Marty Saldivar, Matthew Doyle, Peter Moulton, Rachel Brombaugh, Robert Briggs, Shay Bauman, Srirup Kumar, Stephanie Chase, Ted Drennan, Virginia Lohr, and Willard Westre.

Questions Received

Questions from attendees are posted in the order in which they were received. The webinar began at 1:00 PM PDT and ended at 4:35 PM PDT.

Name	Time Sent	Comment
James Adcock	**1:05 PM**	Here we go again.
James Adcock	**1:09 PM**	That's fine -- let's get on with it.
Don Marsh	**1:21 PM**	I forgot... did customers lose gas service after the Enbridge incident? Or was PSE able to maintain service?
Bill Donahue	**1:22 PM**	PSE customers did not lose service
Don Marsh	**1:22 PM**	Thanks for the answer, Bill.
Court Olson	**1:39 PM**	Does Scenario #5 assume short term or long term gas shut down?
James Adcock	**1:39 PM**	On a "peak coldest winter day" what percent of Puget's supplied natural gas is going to Puget's NG electric generators?
Don Marsh	**1:40 PM**	Slide 16: was this forecast updated for the economic impacts of COVID?
Court Olson	**1:40 PM**	When is PSE going to realize that Gas demand will soon be declining as customers switch to clean electricity for heating space and water?
James Adcock	**1:42 PM**	What has been you Peakest Peak Day condition in terms of actual MDth/day, in the last 10 years?
Fred Huette	**1:44 PM**	also have a question Slide 16
Stephanie Chase	**1:46 PM**	Could you discuss the status of the Tacoma LNG project and when it is anticipated to be online?
Josh Rubenstein	**1:48 PM**	What carbon emissions reductions efforts are calculated into the resource forecast in slide 16?
Don Marsh	**1:52 PM**	Is the Tacoma LNG facility used for electric generation as well, or does it only supply PSE's gas customers?
Don Marsh	**2:01 PM**	Slide 17: question
Court Olson	**2:08 PM**	Your statement on the McKinsie analysis predicting a fall of of gas demand after 2030 seems to be in conflict with PSEs gas demand forcast curve. How do you resolve that conflict?
Fred Huette	**2:09 PM**	Is PSE considering the updated peer-reviewed study results concerning upstream emissions from BC and Alberta gas production and transportation? We submitted extensive detail in the electric IRP process.
Fred Huette	**2:11 PM**	slide 19: what is involved in upgrading from 50% to 100% firm for Station 2->Sumas? To your knowledge is Enbridge willing to offer that service?
Fred Huette	**2:12 PM**	slide 19: the cross-BC upgrades (it's Fortis most of the way as I recall, with about 250 mmcfd/d of current capacity) has been in discussion for many years. What is the current status?
Fred Huette	**2:17 PM**	slide 19: WIlliams/NW Pipeline declared a Deficiency Period starting Sep. 25 which is continuing and will result in "anomaly repairs" next week resulting in zero flow for several days. While this is a short term issue, to what degree is PSE including this kind of reliability risk in long term planning? http://northwest.williams.com/NWP_Portal/operations.action
Court Olson	**2:18 PM**	How does PSE intend to promote and implement gas conservation?
Anne Newcomb	**2:18 PM**	This looks like a lot of new NG capacity coming online. Are you expecting a spike in demand for existing customers and or new customers?
Court Olson	**2:21 PM**	Your slide 21 shows DSR impacts from mandated energy code standards. How do you reconcile this with the steadily increasing demand projection by PSE well into the future?

David Perk	**2:22 PM**	Thank you Don for raising this essential point.
James Adcock	**2:22 PM**	Comment: Puget by itself consumed the sustainable carbon footprint of one million human beings.
Josh Rubenstein	**2:22 PM**	Slide 20: How does the conservation cost bundling data incorporate the social cost of greenhouse gas emissions referenced in an earlier slide?
Virginia Lohr	**2:24 PM**	Slide 21: Are you assuming there will be no new codes or standards, such as those in Seattle, developed in future years?
Fred Huette	**2:29 PM**	In response to the facilitator: I'm happy to wait until after others who haven't asked questions, but we are asked to provide questions in this format and having done so, would like to hear at least initial responses.
James Adcock	**2:31 PM**	I think the "live" conversations are good, and again I would encourage PSE to start planning appropriate amounts of time in their IRP meetings, including time for more technical questions like Fred wants to ask. IRPs are supposed to be -- according to law -- about "Public Participation" NOT JUST PSE "Presentations" !
Fred Huette	**2:34 PM**	Also to note that I have to leave at 3 for an Oregon Department of Energy workshop. I will submit any questions not resolved in writing, but encourage PSE and the facilitation team to determine if this process is as efficient as it could be.
Court Olson	**2:36 PM**	You have collectively just admitted that gas demand will be falling off after 2030 due to utilities usage impacted by CETA rules. Surely the utilities get their gas from the same pipelines that you have shown us. So why is it that PSE is promoting increasing gas pipelines and gas storage facilities in Washington, when total gas demand (including from utilities) will surely be dropping after 2030?
Don Marsh	**2:38 PM**	PSE is not projecting increasing demand after DSR, so the "Resource Alternatives" will probably not be needed on slide 19.
Court Olson	**2:44 PM**	Energy code tightening every 3 years is required by existing Washington law. Every three years to 2031, the new building energy efficiency must tighten by about 9% on the afterage. Is this being included in your modeling?
Anne Newcomb	**2:55 PM**	Great question Court!
Srirup Kumar	**2:56 PM**	Would modular anaerobic digesters be eligible for conservation incentives offered to industrial, institutional and commercial clients?
Court Olson	**3:02 PM**	So glad to hear that there is no new gas resource need on the horizon!
Don Marsh	**3:02 PM**	25-26: question
Court Olson	**3:04 PM**	Whoops. Slide 26 still projects a net demand increase if I read it right. How do you reconcile the chart with what you just said that there is no demand increase seen on the horizon?

Anne Newcomb	**3:09 PM**	Slide 26. On March 19, 2020, the Governor signed HB 2311 - 2019-20, Amending state greenhouse gas emission limits for consistency with the most recent assessment of climate change science. It became effective on June 11, 2020. It states: "Based on the current science and emissions trends, as reported by the department of ecology and the climate impacts group at the University of Washington, the legislature finds that avoiding global warming of at least one and one-half degrees Celsius is possible only if global greenhouse gas emissions start to decline precipitously, and as soon as possible." Many of your responses to questions seem to assume we are in the same position climatically that we have been in for the past 50years, but we are not. Is PSE aware of this recent legislation and what are you doing to look not just at meeting your optimistic gas growth projection, but to reduce it?
James Adcock	**3:16 PM**	Comment: NG companies can and do make huge mistakes -- huge failures -- such as the California Aliso Canyon gas leak. I would hate to have a similar, or larger, failure at Tacoma LNG, which among other things would "take out" 30-40 schools.
Virginia Lohr	**3:23 PM**	Slide 30. You selected the IAP2 level of "Inform," the lowest level of public input, for the portion of this webinar on draft natural gas portfolio results. This level seems appropriate to me for simply presenting or informing us of the results of work you have done. You have also selected to use the IAP2 level of "inform" for a large portion of this webinar for: gas portfolio model, resource need, levelized gas prices, resource alternatives, and natural gas peak day planning standard. None of these topics involve just telling us results, but telling us how you plan to proceed. Why is this an appropriate level for an IRP meeting with many highly educated people volunteering their time to give useful and meaningful input for PSE to consider incorporating in your 20-year planning?
Don Marsh	**3:24 PM**	The Tacoma LNG facility is a big safety concern. If it is not absolutely essential (see slide 26), it is unethical to ask nearby residents to live with a potentially fatal risk of accident. PSE's website says "Our ethics: Doing the right thing." We expect PSE to follow its own ethics or take the words off its website.
James Adcock	**3:26 PM**	Slide 32 -- what additional "planning margin" in percentage -- if any -- does PSE build into their NG systems in addition to this 52 HDD planning standard?
Alison Peters	**3:28 PM**	Virginia, to your question about the inform level. This is the level where a sponsor such as PSE provides the public with the information needed to understand PSE's decision making process, including their forecasts. PSE welcomes questions about these topics before the webinar (in a Feedback Form) and we stop for clarifying questions frequently during this section. The Involve level for today will begin in just a minute - the next section.
James Adcock	**3:29 PM**	Slide 33 -- what additional planning margin, in percentage, is PSE building into their Natural Gas systems in response to PSE customer surveys that show that those customers put high value in keeping their gas on?
James Adcock	**3:32 PM**	Slide 35 Raise Hand.
Don Marsh	**3:33 PM**	Is slide 35 showing us 2005 data? Is it possible that things might have changed in the last 15 years?

Court Olson	**3:34 PM**	Slide 35 benefits do not apparently include the benefit of reduced GHG emssions, so this study needs to be replaced with a modern one that includes the social cost of carbon benefit.
Don Marsh	**3:34 PM**	Slide 36: question
Court Olson	**3:37 PM**	On Slide 37, has PSE studied the trend in changing cold peaks due to climate change in recent years? Doesn't that affect consumption and demand
James Adcock	**3:53 PM**	Puget is freezing me out because they know that 1950s weather data is no longer relevent re natural gas planning, as coldest winter days back then were 18 or more degrees colder than they are nowadays, due to large change in climate in PNW coastal weather -- PSE's region. As such, PSE's slide presented today -- which are based on 1950's weather data, are complete nonsense.
David Perk	**3:53 PM**	https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/Oct_20_webinar/Webinar%209:%20Updated%20sensitivities%20list.
Deborah Reynolds	**3:54 PM**	I agree that the peak day planning standards study should be fully described - what was provided in the slides today was a solid overview but not very detailed. The study should either be updated for 2020's customers and statutes, or supported as still accurate and useful.
Don Marsh	**3:56 PM**	How many portfolios can you study?
Court Olson	**3:56 PM**	I wonder how we can prioritize portfolio sensitivities? If we had to rank them, it might suggest that lower ranking sensitivities can be discarded, when that may not be the intent. Please give us guidance and the link to the place where we offer comments.
Virginia Lohr	**3:56 PM**	Please read my question I posted at 3:09. It addresses Elizabeth's question.
Don Marsh	**3:57 PM**	Raise hand
Don Marsh	**3:59 PM**	When I try to open the spreadsheet, it says "Can't open in protected view." I can't see it.
Brian Grunkemeyer	**4:00 PM**	I have the same spreadsheet problem as Don.
Deborah Reynolds	**4:01 PM**	I'm able to open the file in my native Excel desktop program. We've had some problems with this file when using it in Office 365 and Sharepoint Online.
Don Marsh	**4:01 PM**	I have Office 365. Hmm.
Alison Peters	**4:02 PM**	Don, I'm able to open it as well. For everyone else, it is linked to the meeting materials for 10/20.
Brian Grunkemeyer	**4:03 PM**	Got it. As Deborah hinted.. Run Excel. File -> Open -> Browse, then paste in the URL
Don Marsh	**4:04 PM**	Got it off the IRP website. Thanks.
Brian Grunkemeyer	**4:06 PM**	There is a colon ':' in the file name. That doesn't work well on Windows for reasons (NTFS streams). PSE, please consider not using :'s in file names in the future.
Don Marsh	**4:08 PM**	Good debugging, Brian! You must have worked at Microsoft once upon a time! :)
Brian Grunkemeyer	**4:09 PM**	I wrote .NET's FileStream class. You learn some things.
Court Olson	**4:09 PM**	Slide 46 & 47. How does PSE plan to produce Hydrogen? From methane or by elctrolysis?
Alison Peters	**4:09 PM**	Thank you, Brian. We can upload it again without the :

Srirup Kumar	**4:12 PM**	Slide 47: Does the 3-5% RNG estimate include the distributed RNG resources embedded in food, bev & ag waste?
Don Marsh	**4:19 PM**	Slide 52: question
Brian Grunkemeyer	**4:22 PM**	Bill, I'd like your gut feeling on this. What if you are only allowed to put carbon-neutral gas in the pipeline? Can your customers cover the fixed costs for the pipeline system at an acceptable cost?
Srirup Kumar	**4:22 PM**	Thank you. Following-on, would modular anaerobic digesters be eligible for conservation incentives offered to industrial, institutional and commercial clients?
James Adcock	**4:24 PM**	Why would you turn "Excess Electricity" into Hydrogen as opposed to Battery Storage or Pumped Hydro, or sell it to BPA for long term storage behind their dams as stored potential energy?
Peter Moulton	**4:24 PM**	WSU/Commerce assessment of RNG potential did take food/ag wastes into consideration, along with biomass gasification pathways. Conclusion was closer to 10% displacement potential if all pathways are taken into consideration...
Srirup Kumar	**4:22 PM**	Thank you.
Brian Grunkemeyer	**4:24 PM**	Thanks Bill. Just food for thought - please consider some policy goal like RNG-only by 2035. IE, say the Legislature incentivizes fuel switching, etc. It would be useful for PSE to have an answer to whether this might be an obtainable policy goal to set.
Peter Moulton	**4:28 PM**	I wouldn't characterize the ~10% estimate as "very optimistic," it's a realistic assessment of potential. Cost is different question...
Alexandra Streamer	**4:32 PM**	Link to Feedback Forms: https://pse-irp.participate.online/feedback-form
Srirup Kumar	**4:32 PM**	Note: a recent study by the Lawrence Livermore National Laboratories found that converting organic waste to clean fuels like renewable natural gas (RNG) holds the greatest potential for negative emissions at the lowest cost https://www-gs.llnl.gov/content/assets/docs/energy/Getting_to_Neutral.pdf
Srirup Kumar	**4:36 PM**	Thank you!

PSE IRP Feedback Report
Webinar 8: Natural Gas IRP
October 14, 2020

10/28/2020

The following stakeholder input was gathered through the online Feedback Form, from October 7 through October 21, 2020. PSE's response to the feedback can be found in the far-right column. To understand how PSE incorporated this feedback into the 2021 IRP, read the Consultation Update, which will be released on November 4, 2020.

Feedback Form Date	Stakeholder	Comment	PSE Response
10/14/20	James Adcock	Please do your "mike checks" and other "technology presentation checks" *before* the start time of the meetings. There is no reason why you guys should be wasting everyone's time "fixing" things after the start time of the meeting. When you do so, you are implying that your time -- "PSE's time" -- is important, but that the time and energy of IRP participants is *not* important!	We thank our stakeholders for their patience and understanding. PSE regularly checks the technology and audio before meetings, however, sometimes technology fails. Even though PSE was able to recover the presentation in a timely manner, we apologize that this caused an inconvenience for our stakeholders.
10/14/20	James Adcock	Slide 36 -- PSE continues to use archaic "weather data" going back to the 1950's -- when the "coldest winter day" was as cold as zero degrees F. In the last 20 years "coldest winter day" has only been 18 degrees -- 18 HDD less! Can you please create an up-to-date version of Slide 36 which only uses "weather data" from at most the most recent last 20 years -- and then rely on that up-to-date information rather than relying on ancient out-of-date data for all of your NG planning efforts? When PSE continues to use ancient out-of-date weather data what PSE is really saying is: "Puget Continues to Deny the Reality of Climate Change!"	Thank you for your comment. As was discussed in the webinar, the gas planning standard is very different from the electric peak planning standard. This has to do with the long time, higher cost and increased safety concerns in the event of a gas outage. The planning standard for the natural gas portfolio is based on a cost/benefit analysis. While PSE will not update the cost/benefit analysis for this IRP, the gas planning standard is in line with industry standards and other gas utilities in the region. The gas-planning standard was successfully tested in early October 2019 when a pipeline ruptured in B.C. and PSE did not experience any gas service customer disruptions. For clarification, the coldest day in the weather data used by PSE is a 24-hour average temperature of 13 degrees, not zero.
10/14/20	James Adcock	Re: feedback about "natural gas sensitivies" -- I suggest creating a "natural gas sensitivity" based on weather data taken only from the last 20 years -- 2000 to 2020, rather than reaching back to archaic weather data from the 1950s.	Thank you for your comment. The effects of warming temperature trends on the demand forecast will be analyzed as a sensitivity that was presented in Webinar 9 on October 20, and has been included in the list of portfolio sensitivities. At the time of this Feedback Report, we have not yet reviewed stakeholder input regarding the temperature sensitivities.
10/14/20	Don Marsh, CENSE	During the October 14 webinar, PSE asked for stakeholder comment on the priority of the portfolio sensitivities (slide 43). I didn't find a way to provide this feedback other than this feedback form, so I hope this is the proper way to do it. My preferred sensitivities, in priority order, and reasoning are as follows: (top priority) 7. High impact SCGHG Reason: I believe PSE's current accounting of SCGHG (slide 17), while high, understates the true impacts of the Social Cost of Greenhouse Gas emissions, as indicated by more recent scientific studies. It is very likely that PSE's numbers will have to be revised upward in the next few years, so we should find out now what the implications will be. 9. Use AR5 to model upstream emissions PSE is using methane leakage rates that are low and not up to date, so the cost of methane emissions is also understated on slide 17. PSE will need to revise these numbers in coming years, so let's see what that will look like. 10. Temperature Sensitivity In every recent IRP meeting, and many of the 2019 meetings, James Adcock and several other stakeholders (including me) have criticized PSE for using up to 70 years of temperature data as a basis for forecasts. The climate is warming, and the effects are dramatic in the case of winter temperatures in the Pacific Northwest. Other states, like New York, are using 15-20 years of data to account for accelerating warming during the past couple of decades. I believe this will have a significant effect on PSE's forecasts, and it is time for us to understand what the magnitude of that effect actually is. 11. Equity focused portfolio Economically challenged customers are bearing the brunt of pollution and climate change. They are the least likely to benefit from clean energy technologies due to costs and the basic struggle to stay afloat financially in these difficult times. Although PSE is required to pursue least reasonable cost solutions, it	Thank you for sharing your preference concerning sensitivities. PSE looks forward to your participation in the selection of the portfolio sensitivities to be analyzed as part of the 2021 IRP. The survey opened on October 19 and remained open thru October 27. PSE's responses from the numbers you provided are as follows: 9. Thank you for your comment. AR5 to model upstream emissions is included in the sensitivity selection for the 2021 IRP. 10. PSE will be running a temperature sensitivity as a "must run" sensitivity. Temperature sensitivities options were presented and further discussed with stakeholders at the October 20 Webinar 9 meeting. Your request to use the most recent 15-years of data is included in our proposed sensitivities. 11. Thank you for your comment and concern. PSE shares your concern. PSE looks forward to stakeholder feedback during the November 16 webinar when we discuss the approach to the Highly Impacted Communities and Vulnerable Populations Assessment and the Clean Energy Action Plan. 12. Thank you for your comment. 13. Thank you for your comment. 14. Thank you for sharing your preference for applying the discount rate. 15. Thank you for sharing your thoughts on a CO2 tax. The idea for this sensitivity is to include a federal CO2 on top of the SCGHG currently being modeled. 16. Thank you for your comment.

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		is also ethically bound to provide equitable solutions for all its customers. An equity focused portfolio accords with our values and respect for all customers. 12. 6-yr ramp rate It is very difficult to forecast what conservation opportunities will be available in 10 years. PSE says it is impossible to forecast technology and societal priorities in 20 years, and I agree! Six years is a reasonable horizon for these forecasts, so I support pursuing all available conservation in six-year increments. This also reflects the urgency of doing everything we can to avoid environmental catastrophe for future generations. 13. Fuel switching from gas to electric I believe fuel switching will accelerate as technology options become available and awareness builds that natural gas is not a "clean" fuel, but rather extremely detrimental to the well-being of people and the planet. In the past four years, my family has cut our gas use by a factor of five by installing an on-demand hot water heater, heat pump, and induction stove. There are several additional things we can do to cut our gas use even further. I believe this trend will start to take hold more broadly, and may be accelerated by new regulations at the city and county levels. 14. Social discount rate I believe the current discount rate is distorting the true value of DSR, which is a valuable tool in the implementation of CETA and CEIP. Let's see how much the discount rate is creating headwinds to adoption of more DSR. 15. CO2 tax If the administration changes (and this appears likely), interest in an equitable CO2 tax will increase. Let's understand what that would mean for PSE's planning efforts. 16. Non-energy impacts (NEI) In the spreadsheet, the description of this sensitivity is pretty vague, so I might increase its priority if I understood it better. I strongly believe that PSE needs a lot more Demand Response and conservation, and it is unfortunate that the company is trying to withdraw from its most recent RFP for DR resources. These resources are good for customers, beneficial for the environment, and improve reliability by relieving peak-induced stress on the grid. 17. Low Demand with very high gas price This sensitivity was not described in the spreadsheet, but I assume "very high gas price" includes a high SCGHG cost. If I had to bet, this is the most likely scenario we will experience in 2030. We should understand what the implications are. 18. 8-yr ramp rate This is a good sensitivity to study, but it's a small step from the current 10-year ramp rate. I prefer the more aggressive 6-year ramp rate to gain a good understanding of the effects of a shorter ramp rate. If PSE studies both the 6-year and 8-year ramps, we can get a better understanding of how incremental changes affect the costs and benefits. I don't expect to see a simple linear response. 19. Low demand with mid gas price Assuming low demand is good, but a mid gas price seems unlikely given what we know about SCGHG and upstream emissions. This study will provide an interesting contrast to sensitivity number 1, but it's not a high priority because it is seems unlikely to occur. (lowest priority) 11. Fuel switching from electric to gas This sounds dumb to me, but maybe we will find out how dumb by actually running the numbers. More information is always good. But if you're running out of time to study portfolios, this is the last thing you should spend scarce resources on. For each sensitivity studied, I ask PSE to produce a forecast like the one shown on slide 26. If the adjusted forecast is not lower than the one shown for "2021 IRP BASE Demand after DSR," please provide an explanation. For many sensitivities, the explanation will be obvious, but for some, stakeholders may need a little more insight.	17. Thank you for your comment. 18. Thank you for your comment. 19. Thank you for your comment. A stakeholder suggested a sensitivity of fuel switching from electric to gas. PSE has added all stakeholder requests to the list of sensitivities for further prioritization. Thank you for your comments. Thank you for your suggestion to include a similar graph as slide 17 for any sensitivity that affects the SCGHG Adder or Upstream Carbon cost. Your suggestion is being considered.

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		For any sensitivity that affects the SCGHG Adder or Upstream Carbon cost, please show a graph like slide 17 so we can fully understand the assumptions. Full detail of how you arrived at the new costs (references to studies or existing/future regulations) should also be provided. Sincerely, Don Marsh, 2021 IRP Stakeholder	
10/14/20	James Adcock	Please respond now to the questions I raised in the chat box during the online meeting, where I "raised hand" but you continually refused to acknowledge that "raised hand." During the online Meeting PSE, while refusing to acknowledge my "raised hand" to ask a question, claimed that it is answering my previous-session questions after-the-fact in the Consultation Updates even if it did not answer my questions during the meeting. I have reviewed those Consultation Updates once again, and PSE is NOT in fact answering my questions, but rather -- if doing anything at all --- instead lumping a bunch of people's questions and concerns together, and instead of answering any of those questions, simply restating generically what PSE claims that it is doing already. Please actually respond specifically to the specific questions I asked in this meeting, and previous meeting's chat boxes. And please stop telling other participants in the online meetings that you answering my questions offline in the Consultation Updates, when in fact you are not answering my questions offline in the Consultation Updates.	PSE appreciates your participation and desires to make a space for all stakeholders and provide equal access. PSE regrets that you do not find the Feedback Reports and Consultation Updates adequate. PSE regrets that not all your questions have been addressed and that you do not think you are being provided enough opportunity to participate. PSE's intention to provide a means for all stakeholders to be heard and be part of the 2021 IRP record via the meeting recordings, Q&A Logs, Feedback Forms, Feedback Reports and Consultation Updates. PSE is also available via email at IRP@pse.com. PSE will not be going back to all past meeting records and ask that you consider alerting PSE of any specific gaps. Thank you for using the tools that PSE has provided to engage in this process. Thank you for your comments and continued participation.
10/19/20	David Perk 350 Seattle	House Bill 2311 aligned Washington's greenhouse gas reduction goals with the Paris Accord. In the near term, that requires a 45% reduction of statewide GHG emissions by 2030. The "Gas Resource Need" (slide 16) and "Draft base scenario –DSR sufficient to meet future demand" (slide 26) should reflect that reality. Moreover, HB 2311 requires relevant state agencies to report their reduction plans for the next biennia by June 1, 2022. As a major emitter, PSE will need to supply a plan to reduce its emissions. To work toward that goal the "Stakeholder requested natural gas portfolio sensitivities" (slide 43) should include a sensitivity that addresses the necessary GHG reductions.	PSE looks forward to reviewing the Department of Ecology's progress report at the end of this year, indicating statewide greenhouse gas emissions as well as emissions from relevant key sectors, such as the electricity and/or building sectors. PSE will review Ecology's report, as well as the overall statewide greenhouse gas emissions limits established in HB 2311, in considering potential sensitivities to run for the next IRP cycle.
10/19/20	Elyette Weinstein	As you know, E2SHB 2311 became law, effective June 11, 2020. It requires that, by 2030, Washington State utilities limit anthropogenic emissions of greenhouse gases to achieve a 45% reduction in such emissions below 1990 levels or 50 million metric tons. Please run a sensitivity that fully conforms to the above stated law based on emissions below 1990 levels and another with a reduction of 50 million metric tons. Thank you.	PSE looks forward to reviewing the Department of Ecology's progress report at the end of this year, indicating statewide greenhouse gas emissions as well as emissions from relevant key sectors, such as the electricity and/or building sectors. PSE will review Ecology's report, as well as the overall statewide greenhouse gas emissions limits established in HB 2311, in considering potential sensitivities to run for the next IRP cycle.
10/19/20	Doug Howell, Sierra Club	HB 2311 mandates new GHG targets for the state calling for 95% elimination of fossil fuel by 2050 and 45% reduction in fossil fuel by 2030. PSE needs to run a scenario or at least a sensitivity of how PSE is going to meet this 2030 interim target for its gas utility. In the last IRP meeting on the gas utility, PSE is planning on demand remaining relatively flat through	PSE looks forward to reviewing the Department of Ecology's progress report at the end of this year, indicating statewide greenhouse gas emissions as well as emissions from relevant key sectors, such as the electricity and/or building sectors. PSE will review Ecology's report, as well as the overall statewide greenhouse gas emissions limits established in HB 2311, in considering potential sensitivities to run for the next IRP cycle.

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		2030. This is unacceptable. PSE needs to demonstrate a path forward to achieve the state climate goals. Run a scenario or at least a sensitivity showing a 45% reduction in gas use by 2030.	
10/20/20	Josh Rubenstein	To both PSE and the facilitators, the fact that you told the public that we were "involved" in the October 14th IRP meeting stretches the imagination. After three hours of "inform" we got to the one slide with "involve" level of IAP2 participation, at which point PSE said that based on the data they had presented they did not believe that further sensitivities analysis needed to be done on the gas forecasts. In other words, PSE asked us to agree that public involvement was unnecessary at the only point in their presentation where public involvement was planned. PSE and EnviroIssues staff responsible for this process lose credibility in the eyes of the public when you demonstrate no interest or ability to engage the public and instead choose to only "inform." In this case PSE, I heard you trying to cut out the public voice. How will you improve your public process to seek input, rather than ask for permission to not receive input? EnviroIssues, as the process experts in this situation, it is your job to uphold a process that is truly public. What will you do to improve the opportunities for public participation in the meetings you facilitate? In response to the question, PSE should prioritize every sensitivity that may lead to a reduction in global warming pollution. PSE ratepayers and the public have payed, are paying, and will continue to pay the social cost of PSE's carbon pollution. It's high time that PSE start working to reduce the demand for gas so that we PSE can begin reducing the damage you inflict on our climate and our society. If the first step in doing that means running sensitivity models, then you should do that rather than ask for permission not to. Improve public process and accountability to fully invite public input. When the public is seeking lower climate pollution, incorporate that into PSE's actions in a meaningful way. Model all the sensitivities for the gas IRP that could lead to lower gas usage or demand, so that PSE will feel that they have the information they need to lower and then eliminate regional reliance on fossil fuels.	Thank you for your thoughtful comments and suggestions concerning PSE's 2021 public participation process. PSE agrees that for future meetings we will consider placing, "involve" level topics as priority on the agenda to provide for more opportunity for engagement. PSE has decided the level of engagement for each topic to the level that we can commit concerning that topic. Thank you for your comments and suggestions concerning sensitivities.
10/21/20	Bill Westre, Union of Concerned Scientists	Slides 16 and 26: The business-as-usual presupposition behind these charts is illusory at best and not reflective of the reality of our current situation. We need to turn to science for a better perspective of what is real. The preponderance of reputable scientists have formed a consensus that we must eliminate all fossil fuel emissions by 2045. To not do so would lead to catastrophic consequences for citizens in every country. This is articulated in the IPCC Paris Agreement and its subsequent reports. The Federal Government may for the moment be attempting to get out of this agreement, but Washington State is committed to the Paris GHG reductions by the passage of HB 2311 last year. HB 2311 requires, with respect to year 2005, all GHG emissions be reduced by: 15% by July 1 2020 45% by 2030 70% by 2040 90% by 2050 These required emissions reductions apply to nearly all non-natural emissions including those by any corporation that produces or distributes methane which is the primary constituent of natural gas. The Bill also requires that by June 1st 2022 the relevant state agency must report to the Dept of Ecology the actions planned for the next biennia to meet these emission reduction targets. This date falls within the 4-year time construct of the 2021 IRP. As a major supplier of natural gas produced GHG emissions, PSE will surely be called on to submit its plan for these reductions. Question 1 - Is PSE willing to create a scenario that includes plan options that reflect the above listed reductions in the 2021 IRP? If not, why not?	Thank you for your comments and questions. PSE supports customer choice and we accommodate and support customers switching from gas to electric service. PSE looks forward to reviewing the Department of Ecology's progress report at the end of this year, indicating statewide greenhouse gas emissions as well as emissions from relevant key sectors, such as the electricity and/or building sectors. PSE will review Ecology's report, as well as the overall statewide greenhouse gas emissions limits established in HB 2311, in considering potential sensitivities to run for the next IRP cycle. The above response covers questions 1, 3, 4 and 5; thank you. Concerning question 2: PSE will be addressing this question in the Consultation Update on November 4, 2020.

Feedback Form Date	Stakeholder	Comment	PSE Response
		Question 2 – PSE alludes to its responsibility to respond to these requirements by referring to renewable gas, hydrogen, and gas-to-electric switching. What other options are available to PSE to make these reductions? Question 3 - Will PSE inform its customers of the required reductions and its long-term impact on them? Question 4 – Will PSE incorporate these requirements into its gas conservation plan? Question 5 – Will PSE intensify its conservation rebate incentives to help its customers make the required transitions.	
10/21/20	Virginia Lohr	I do not agree with PSE's proposal to run no gas sensitivities. You showed us one set of results that indicated you would be able to meet most of your gas load, but that does not guarantee you will. The future is uncertain, as Covid has clearly demonstrated, so not running alternate sensitivities to look at alternate possible futures seems clearly imprudent. During the meeting, I brought up HB 2311 - 2019-20: Amending state greenhouse gas emission limits for consistency with the most recent assessment of climate change science. It became effective on June 11, 2020. While this bill does not include specific language requiring PSE to take action, it does present the clear intent of the legislature to take strong action to reduce greenhouse gas emissions. It is not improbable that a bill similar to CETA but directed towards utilities that supply natural gas rather than focused on electricity, would be enacted. I strongly recommend PSE run a gas sensitivity based on the updated greenhouse gas emission reduction targets in HB 2311.	Thank you for your comments and recommendations. PSE looks forward to reviewing the Department of Ecology's progress report at the end of this year, indicating statewide greenhouse gas emissions as well as emissions from relevant key sectors, such as the electricity and/or building sectors. PSE will review Ecology's report, as well as the overall statewide greenhouse gas emissions limits established in HB 2311, in considering potential sensitivities to run for the next IRP cycle.
10/21/20	Anne Newcomb	Please add requirements of GHG reductions from E2SHB 2311 to PSE Natural Gas sensitivities. Requirements: Greenhouse Gas Emissions Reductions. Washington must limit anthropogenic emissions of greenhouse gases to achieve the following reductions for the state:? By 2020, reduce overall emissions of greenhouse gases in the state to 1990 levels, or 90.5 million metric tons. By 2030, reduce greenhouse gas emissions to 45 percent below 1990 levels, or 50 million metric tons. By 2040, reduce overall emissions of greenhouse gases in the state to 70 percent below 1990 levels, or 27 million metric tons. By 2050, reduce overall emissions of greenhouse gases in the state to 95 percent below 1990 levels, or 5 million metric tons, and achieve net-zero greenhouse gas emissions. Thank you for listening to Stakeholder comments and recommendations! It is unsettling for me to see PSE is still considering Natural Gas (NG) expansion, as shown in slide #19, even with new Washington state laws in place and more coming online to address Greenhouse Gas emissions.	Thank you for your comments and recommendations. Slide 18 shows all natural gas resource alternatives available to PSE, however, as we discussed later in the presentation, conservation meets future gas growth for the base scenarios and no natural gas expansion is needed for the base scenario.

Feedback Form Date	Stakeholder	Comment	PSE Response
		Hopefully PSE will add new WA state law requirements, including E2SHB 2311, to the 2021 IRP (NG) sensitivities to be run. Well wishes to all of you, Anne Newcomb Attached: http://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bill%20Reports/House/2311-S2.E%20HBR%20FBR%2020.pdf?q=20201022100749	
10/21/20	Robert Briggs, Vashon Climate Action Group	On March 19, 2020, Governor Inslee signed HB 2311, which updated the state's greenhouse gas emissions limits. Those emissions now need to be 45% below 1990 levels by 2030, 70% below 1990 levels by 2040, and 95% below 1990 levels by 2050. During the webinar, PSE proposed to abandon doing all gas sensitivity analyses because current gas resources appear adequate to meet near-term demand. I strong urge PSE to reject that idea. Given the clear legislative intent expressed in HB 2311, PSE needs to be planning its gas system to comply with state emissions limits. As the largest gas utility in the state of Washington, PSE needs to recognize the importance of its fully complying with state law to the state's credibility and reputation. I would argue that complying with state law should be included as a baseline assumption. I would think it financially imprudent for PSE to fail to include a reduction of gas emissions in conformance with HB 2311 at least as a scenario, given the clarity with which the Legislature has now spoken. Future legislation is likely to make these limits more stringent not less. There is also an equity dimension to this situation that PSE, the WUTC, and the Public Counsel's office need to take responsibility for managing. As the direct use of gas is abandoned in favor of electricity for both cost and GHG emissions reasons, there will be fewer and fewer gas customers to shoulder the costs of maintaining gas infrastructure. The need to recover those costs with fewer sales will drive up rates, leaving those least financially able to cope with the consequences of an essential energy service experiencing a financial death spiral. It is essential that PSE with oversight from the WUTC proactively manage the scaling back and orderly withdrawal of this service. How will PSE be able to manage this development, which now appears inevitable, if it continues to pretend that change is not coming? This process has large implications for the electric side of PSE's business. It seems important that the consequences for electricity demand of contracting gas service be fully explored in PSE's electric IRP as well. I recommend that PSE include a gas sensitivity that reflects a contraction of gas deliveries to direct users proportionate with their contribution to state greenhouse gas emissions and in conformance with the schedule for reductions specified in HB 2311.	Thank you for your comments and recommendations. PSE looks forward to reviewing the Department of Ecology's progress report at the end of this year, indicating statewide greenhouse gas emissions as well as emissions from relevant key sectors, such as the electricity and/or building sectors. PSE will review Ecology's report, as well as the overall statewide greenhouse gas emissions limits established in HB 2311, in considering potential sensitivities to run for the next IRP cycle.
10/21/20	Kyle Frankiewich, WUTC	Questions and comments from presentation were provided by reference slide number. Recommendations were provided as well.	Thank you for your questions and recommendations. PSE inserted each item below along with PSE's responses.
10/21/20	Kyle Frankiewich, WUTC	Slide 10: I'm not clear on why Enbridge is a good example of a "peak event." Is the company's argument that the level of overbuild / redundancy / resilience in the system was tested and performed well during a major infrastructure outage outside of PSE's control?	The Enbridge event was not characterized as a peak event, but rather an example of the value of diversity of the portfolio. There is no excess capacity in the upstream pipeline and storage system (all of it is contracted) so when one part fails PSE has to rely on other parts of the portfolio and other planned responses (curtailment of interruptible loads and lower priority firm loads) in order to maintain service on the gas system.

Feedback Form Date	Stakeholder	Comment	PSE Response
10/21/20	Kyle Frankiewich, WUTC	Slide 12: Seems that the NG line of business (LOB) more consistently sources gas from the Rockies than the electric LOB. Why is this? Broadly, since the low prices brought about through fracking, what is the historical ratio of sourcing from BC, Alberta and the Rockies?	The PSE Electric (Generation) LOB does not source any gas from the Rockies, and never has, as it does not hold any firm pipeline capacity from the Rockies. PSE began acquiring pipeline capacity for generation well after all capacity from the Rockies was fully contracted. While a few expansions from the Rockies to the Pacific NW have been proposed, none were economic or attracted enough interest to be built. The table below provides a summary of the natural gas supply sources for the natural gas utility and a second table for the natural gas for power (the natural gas generators for the electric utility).

Gas Supply source for PSEG and PSEE for 2010 through 2019

Supply sources are limited by the firm pipeline capacity held by each respective portfolio

PSE Gas Customer Portfolio by year:	BC at Station 2 or Sumas	Alberta in Alberta	US- Rockies & San Juan Basin	Total
2019	49.4%	19.2%	31.4%	100.0%
2018	49.0%	17.2%	33.8%	100.0%
2017	54.8%	19.1%	26.1%	100.0%
2016*	56.0%	21.0%	23.0%	100.0%
2015*	57.0%	24.0%	19.0%	100.0%
2014	57.1%	18.1%	24.8%	100.0%
2013*	56.0%	21.0%	23.0%	100.0%
2012*	51.0%	20.0%	29.0%	100.0%
2011*	49.0%	15.0%	36.0%	100.0%
2010	42.8%	18.7%	38.5%	100.0%

PSE Power Generation Portfolio by year:	BC at Station 2 or Sumas	Alberta in Alberta	Alberta at Stanfield	Total
2019	54.4%	19.7%	25.9%	100.0%
2018	72.2%	18.0%	9.8%	100.0%
2017	69.9%	21.8%	8.3%	100.0%
2016*	64.0%	20.0%	16.0%	100.0%
2015*	76.0%	1.0%	23.0%	100.0%
2014	91.2%	0.0%	8.8%	100.0%
2013*	88.0%	0.0%	12.0%	100.0%
2012*	93.0%	0.0%	7.0%	100.0%
2011*	83.0%	0.0%	17.0%	100.0%
2010	77.5%	0.0%	22.5%	100.0%

* no decimal places

Feedback Form Date	Stakeholder	Comment	PSE Response
10/21/20	Kyle Frankiewich, WUTC	Slide 14: The CPA was discussed in July, but the assessment itself was not shared, and the presentation did not focus much on the gas LOB. What kind of demand-side resources are evaluated? Are any demand response measures considered?	The draft report of the CPA will be ready and provided with the draft IRP in January 2021. The July webinar included a discussion of the results of the natural gas measures [see slides 57 to 64 from the slide deck for the July Webinar; Webinar 5]. There was no discussion of natural gas demand response, as there are no gas demand response programs being considered [see detailed reply below].
10/21/20	Kyle Frankiewich, WUTC	Slide 16: How many IRPs have assumed that the Tacoma LNG facility is necessary to meet the forecasted natural gas resource need in the near term? What is the current projected online date for the facility?	PSE anticipates the Tacoma LNG plant to begin commissioning and testing in late January 2021 and begin normal operation in Q1 2021. The 2017 IRP and the 2019 IRP process assumed the Tacoma LNG facility as necessary to meeting forecasted natural gas resource need for the IRP study period.
10/21/20	Kyle Frankiewich, WUTC	Slide 16: follow-up to Participant Adcock's question - How is PSE's electric LOB factored into planning for the company's gas LOB? Bill Donahue clarified that gas supply and transportation books are fully separated between the lines of business. Is the electric LOB a transportation customer in any way?	PSE will be addressing this question in the Consultation Update on November 4, 2020.
10/21/20	Kyle Frankiewich, WUTC	Slide 16: follow-up to Participant Olson's question - could PSE share the rate of voluntary cancellations of service for natural gas customers? Is there evidence of growing customer 'defection' (if that is the appropriate word) away from natural gas? Also, to echo Participant Adcock's question, we would appreciate a list of peak throughput days for each of the last winter seasons for added context in understanding the company's forecast.	PSE will be addressing this question in the Consultation Update on November 4, 2020.
10/21/20	Kyle Frankiewich, WUTC	Slide 18: While no projects were listed for the Tacoma LNG facility or the Jackson Prairie storage facility, there may be other projects that do not reach the system-level focus of this presentation which nonetheless would benefit from consideration in the IRP. What drives decision-making for potential investments in facilities used by PSE's natural gas utility function but also marketed to other wholesale customers?	Opportunities for utility scale natural gas resources are currently very limited. Option 6 on slide 18 is related to Tacoma LNG, which can be more fully utilized if distribution bottlenecks can be eliminated to allow more vaporized gas reach a wider customer base. The Jackson Prairie owners have determined that given current technology and our current understanding of the underground reservoir, further expansion of the project could cause inappropriate risk to the existing resource, so no expansion is currently proposed. The only resource that is offered (by PSE) to other parties is Tacoma LNG, and that shared use is what made the project cost-effective to PSE. The use of Tacoma LNG by Puget LNG LLC is complimentary not additive to PSE's use as a peaking resource. PSE would consider shared use of other resources if that led to lower costs for PSE customers, but none have been identified.
		Slide 20: Based on staff's current understanding (see recommendation 1), the mandate to acquire all cost-effective conservation includes PSE's transportation customers. Has PSE calculated a cost-effectiveness threshold for these customers? How is the company analyzing transportation customer potential?	PSE does not acquire any resources to provide gas or upstream capacity to serve transportation customers so there are no avoided costs to account for.
		Slide 20: All conservation must be considered in new gas CPAs. How is PSE analyzing and including conservation potential within the industrial customer class (see recommendation 4)? For clarification, what conservation offerings are currently offered to industrial customers who receive gas directly from PSE – that is, industrial customers who are not transportation-only customers?	The non-transport industrial customers are treated the same as non-transport commercial customers with respect to any conservation offerings. The non-transport customers all contribute to the conservation rider and are all eligible for conservation offerings.
		Slide n/a: This presentation did not present any distribution reinforcement projects proposed by PSE. What are PSE's thresholds for defining run-of-the-mill O&M reinforcements as compared to larger projects requiring IRP vetting? What systems are in place for distribution-level pipeline safety (San Bruno, Greenwood, Baltimore)?	Distribution system reinforcement projects are part of the distribution system planning process and are planned when minimum pressure/flow criteria are met on the system based on peak hour design day modeling. Potential solutions are then determined and run through a benefit/cost analysis to help to determine the preferred solution. These projects are typically capital projects. Similarly, most maintenance planning projects involve the replacement of an existing property unit and are therefore capital. There is not necessarily a threshold for funding the remaining O&M projects. O&M based programs may include a backlog of known projects or can be placeholders for unplanned projects for the current year. The funding level is established based on the program plan for reducing the backlog or historical trending for unplanned work. Distribution pipeline safety is governed by PSE's Distribution Integrity Management Program (DIMP). PSE currently has 34 DIMP Programs that identify and mitigate pipeline safety risk in the distribution system. Also, an annual review of the distribution system is conducted each year to identify new threats, prioritize risk, develop and implement risk reduction measures, and evaluate results and effectiveness.

Feedback Form Date	Stakeholder	Comment	PSE Response
		Slide n/a: Is DR considered in this IRP as a resource for the natural gas LOB? If I recall, DR was very briefly touched on verbally, but none of the slides discuss DR in the context of the NG LOB.	There is no natural gas DR included in the IRP. There is a DR pilot on the gas distribution system. As stated in the Webinar the gas planning in the IRP is on the gas transmission system that is upstream of the distribution system. Gas is nominated on a daily basis and thus DR which offset peak on an hourly basis on the distribution system does not impact the daily peak on the upstream system.
		Recommendation 1: Conservation, transportation customers, and HB 1257: Staff struggles to find an exclusion for gas transportation customers in the statutory language of RCW 80.28.380. We welcome any and all discussion and legal analysis that might support a conclusion one way or the other as the commission prepares to open a rulemaking on the implementation of this statute.	The purpose of the IRP is to "meet system demand with the least cost mix of natural gas supply and conservation." While RCW 80.28.380 does not include a specific exclusion for gas transportation customers, it is worth noting that PSE does not plan for the supply of natural gas commodity for gas transportation customers. Gas transportation customers procure natural gas commodity independently and separately from PSE's procurement of natural gas commodity for and on behalf of PSE's bundled gas customers. Gas transportation customers do not rely on PSE for the supply of natural gas commodity, and their rates recover the cost of the use of PSE's pipeline system to distribute the natural gas commodity they independently and separately procure from the interstate pipeline to the loads of the gas transportation customer. Additionally, these customers do not pay into PSE's energy efficiency tariff rider and, instead, independently procure their own energy efficiency services. The statutory language in RCW 80.28.380 does not appear to change this long-standing practice, which dates back to the 2002 Stipulation Agreement, Condition 38, which states that "No gas conservation program costs shall be allocated for recovery from natural gas transportation customers."
		Recommendation 2: Incorporation of social cost of greenhouse gas (SCGHG) in cost-effectiveness analysis, and HB 1257: As required by RCW 80.28.380, please provide a deeper explanation of how PSE's cost-effectiveness analysis properly includes all costs of greenhouse gas emissions established in RCW 80.28.395. PSE includes a description of the cost adders in slide 17. How does this $/MMBtu get included in the modeling? Does SENDOUT's modeling allow it to consider conservation measures compared to incremental gas consumption priced at the higher, SCGHG-inclusive $/MMBtu?	The total cost of natural gas used in PSE's modeling includes the SCGHG and the cost of upstream emissions added to the natural gas commodity price. Thus any incremental use of gas is priced at the total cost of natural gas and conservation alternatives in the model will offset this total price when selected.
		Recommendation 3: Upstream emissions – Council methodology: The NWPCC is including upstream emissions estimates for its analysis, including an estimate for US-produced natural gas that is significantly higher than the estimate PSE is using for its own modeling. Why is PSE using a different upstream emissions estimate?	PSE's estimate is based on the US EPA calculations and other studies that have been broadly accepted in the scientific community as discussed in detail in various IRP webinars. PSE and others provided significant feedback to NWPCC's methodology and their estimate was partially adjusted.
		Recommendation 4: Make CPA used for this IRP publicly available: I don't believe the company has shared the Conservation Potential Assessment for electric or gas resources. I understand that participants in the company's conservation-focused advisory group have also not yet seen the document or the underlying data. Please share this document and data (in native file format) with stakeholders by posting it on the IRP webpage, as was done for the 2019 progress report. If the company feels that the CPA should not be shared at this time, please explain why and set expectations for when stakeholders will be able to review the CPA. This would also help stakeholders understand how recent code and standard updates – for example, increasing building efficiency standards – are reflected in the modeling.	The CPA output conservation supply curve data for the gas and electric will be posted online along with this Feedback Report. The CPA draft report is not ready for posting at this time and will be submitted along with the IRP draft submittal expected in January 2021. It will include discussion of the codes and standards updates in the CPA.
		Recommendation 5: Peak day planning standard: We recommend that the company thoroughly explore the 2005 study that arrived at a peak planning standard of 52 HDD for the natural gas LOB. While we would encourage the company to refresh the study to include new resource options, contemporary climatological forecasts and new statutory requirements as applicable, we are open to the argument that the results of the study are still valid in guiding company decisions for 2020-2045. The company should defend its decision to refresh the study, or to not refresh it.	Based on stakeholder feedback we continue to review this planning standard. Any refresh of the benefit/cost study will take time to complete the market research needed to update the value of reliability to customers. There will also have to be consideration of the safety implications for revising the planning standard that will need further review. Due to these elements, it will not be feasible to update this study for the 2021 IRP, however, it is under review for update in the next IRP cycle. Our planning standard is in line with industry standards, including planning standards of the other gas utilities in the region. So while we agree to review a possible refresh, it will not be feasible for the 2020-2045 time period.

Feedback Form Date	Stakeholder	Comment	PSE Response
10/21/20	Kyle Frankiewich, WUTC	Feedback on gas sensitivities: While staff is interested in seeing the results of the sensitivities listed on slide 43, staff appreciates that there is a finite amount of analytical work that can be performed before the IRP must be filed, and that some scenarios will yield more compelling results than others. Staff has binned the sensitivities into the following three categories. Highest priority: 4, 9, 12, 13 Try to make the time: 2, 3, 7, 11 If there is time / if it is simple to do: 1, 4, 6, 8, 10	Thank you for sharing WUTC's priorities concerning gas sensitivities.
10/21/20	Robert Briggs, Vashon Climate Action Group	As someone who has been prodding PSE to take a serious look at hydrogen, I would like to help Bill Donahue in responding to James Adcock's question: "Why would you turn "Excess Electricity" into Hydrogen as opposed to Battery Storage or Pumped Hydro, or sell it to BPA for long term storage behind their dams as stored potential energy?" Batteries are great for dealing with most diurnal storage needs but are not economic for long-term storage. Similarly, hydro in the Northwest provides valuable balancing capability but not long-term storage. Aside from Grande Coulee, virtually all of the main-stem Columbia and lower Snake River dams are run-of-the-river and incapable of long-term storage. The only pumped storage capability in the system are the six pump/turbines in the Keys Plant at Grand Coulee providing just 314 MW, but again these are incapable of long-term storage. PSE should be looking at hydrogen for storage to complement batteries and pumped storage, not to compete with them. Hydrogen can provide long-term storage and meet PSE's needs for dispatchable renewable generation, obviating the need for fueling peakers with natural gas. An aggressive build-out of renewables in the Northwest will inevitably lead to surplus electricity far beyond what the region's power system currently has the capability to store. Making hydrogen can enable PSE to reduce the carbon content of the natural gas it delivers and to provide hydrogen for use as chemical feedstocks and transportation fuels. Any hydrogen PSE sells today would predominantly be displacing hydrogen that would have been manufactured from natural gas. Electrolyzers represent an ideal load for PSE to serve, as they can ramp up and down very quickly, are curtailable, and can run increasingly on zero marginal cost power that would otherwise be curtailed. According to Fortis BC, who is responding to a British Columbia mandate to decarbonize their gas system by 15% by 2030, at least 2/3 of that decarbonization will come through the introduction of renewable hydrogen into their natural gas system. Biogenic sources of methane are inadequate to meet the 15% requirement. Before the end of the decade hydrogen is expected to be flowing into the US through the Sumas hub, according to Fortis. I applaud PSE's foresight in becoming a founding member of the Renewable Hydrogen Alliance. I encourage PSE to continue looking at the role hydrogen can play in meeting decarbonization requirements for both their electric and gas IRPs.	Thank you for your comments and recommendations. As part of the electric IRP, several stakeholders have requested PSE to consider using an alternative fuel such as hydrogen for the peaker plants. The idea for the portfolio sensitivity is to turn the "excess electricity" into hydrogen so it can be used in the peaker plants for reliability instead of natural gas. PSE is currently researching this for the 2021 IRP.

Feedback Form Date	Stakeholder	Comment	PSE Response
		Questions from the webinar requiring follow-up	
10/14/20	James Adcock	On a "peak coldest winter day" what percent of Puget's supplied natural gas is going to Puget's NG electric generators?	In the IRP modeling, we are only showing gas consumption for gas customers. The electric generation side has its own pipeline capacity and buys its own gas. Because PSE peak electric demand is also driven by cold temperature, the gas and electric generation demand can be coincident.
10/14/20	James Adcock	What has been you Peakest Peak Day condition in terms of actual MDth/day, in the last 10 years?	PSE will be addressing this question in the Consultation Update on November 4, 2020.
10/14/20	Fred Huette	Slide 19: the cross-BC upgrades (it's Fortis most of the way as I recall, with about 250 mmcfd/d of current capacity) has been in discussion for many years. What is the current status?	PSE's understanding is that Fortis would consider building the project if parties contract for enough capacity to justify the project. We understand that the minimum contracted volume is above 200,000 Dth/d. This project is not within PSE's control as it would require contracting by other parties in addition to any volumes requested by PSE.
10/14/20	Fred Huette	Slide 19: WIlliams/NW Pipeline declared a Deficiency Period starting Sep. 25 which is continuing and will result in "anomaly repairs" next week resulting in zero flow for several days. While this is a short term issue, to what degree is PSE including this kind of reliability risk in long term planning? http://northwest.williams.com/NWP_Portal/operations.action	PSE relies on 100% of Northwest Pipeline (NWP) availability to meet a design peak day. The type of Deficiency Period and the occurrence of anomaly repairs is not uncommon for any pipeline (and indicates that the pipeline is fulfilling its maintenance obligations) and all pipelines plan and undertake this work in off-peak periods when shippers can use other pipeline capacity. PSE has maintained a very flexible portfolio of resources that allows it to manage around the periodic disruptions.
10/14/20	Srirup Kumar	Thank you. Following-on, would modular anaerobic digesters be eligible for conservation incentives offered to industrial, institutional and commercial clients?	There could be incentives if the particular technology results in energy savings AND those savings are cost effective. More information on incentives for specific projects can be found here: https://www.pse.com/rebates/business-incentives/commercial-retrofit-grants

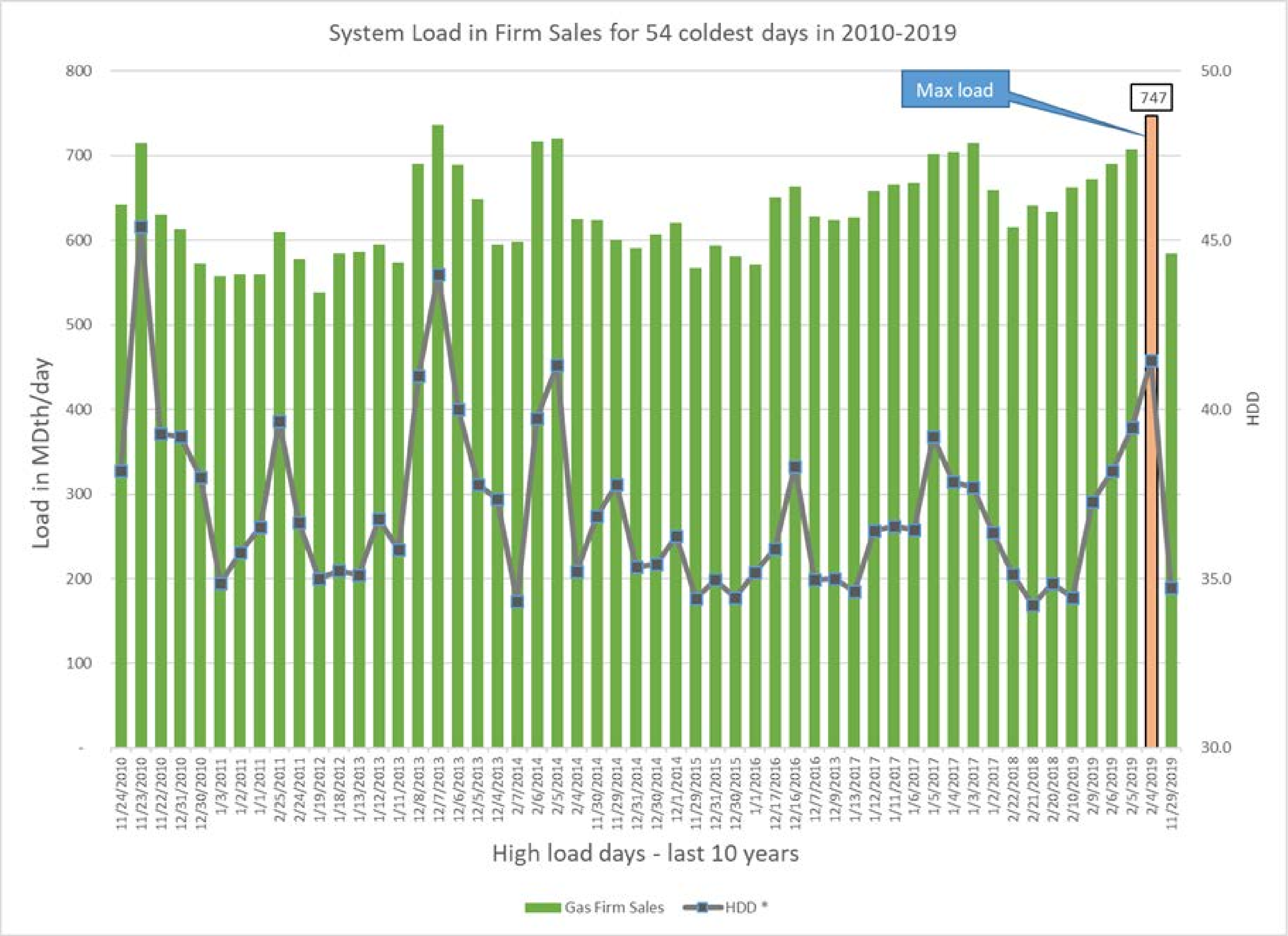
PSE IRP Consultation Update
Webinar 8: Natural Gas IRP
October 14, 2020

11/04/2020

The following consultation update is the result of stakeholder suggestions gathered through an online Feedback Form, collected between October 7 and October 21, 2020 and summarized in the October 28 Feedback Report. The report themes have been summarized and along with a response to the suggestions that have been implemented. If a suggestion was not implemented, the reason is provided.

Temperature Sensitivities, planning standard and recent peak load data

PSE received a request to share the most recent 10 years of peak day load experienced by the gas system. The graph below includes the highest load days over the last 10 years along with the gas system load and associated HDD.



Natural gas for electric versus gas sales

PSE received feedback from Kyle Frankiewich (WUTC staff) as to how much of the electric line of business (LOB) is factored into the company's gas LOB, and whether the electric LOB is a gas transportation customer.

All of PSE gas-fired generation is connected directly to an upstream pipeline (either Northwest or Westcoast) or to Cascade Natural Gas Co. distribution system. Because the gas-fired generation and gas distribution system can have simultaneous peak design conditions, there is no opportunity for shared design day resources. The only opportunity for synergy between the two lines of business is that generation can utilize unused gas LOB pipeline or storage capacity in the low demand summer months (with compensation at fair-market value). In addition, the gas system can rely on the power generaton fleet to curtail gas generation use (and rely on power market supply instead) in an emergency pipeline failure event (e.g.: Enbridge/Westcoast event) in order to maintain pressure in the pipeline.

Gas customer defections

PSE received feedback from Court Olson and Kyle Frankiewich (WUTC) asking if PSE could share the rate of voluntary cancellations of service for natural gas customers and if there was evidence of "defection" away from natural gas service.

PSE has not seen evidence of customer defection. Our most recent 10K shows natural gas customer counts growing over the past there years. Relevant table from the 10K for the fiscal year ending December 31, 2019 (page 19) is provided below:

	Year Ended December 31,		
	2019	2018	2017
Natural gas operating revenue by classes (Dollars in Thousands):			
Residential	$ 613,617	$ 598,923	$ 686,438
Commercial firm	218,302	219,390	251,584
Industrial firm	15,698	17,247	20,077
Interruptible	18,381	21,113	24,317
Total retail natural gas sales	865,998	856,673	982,416
Transportation services	20,283	19,984	21,718
Decoupling revenue	2,296	6,115	3,522
Other decoupling revenue[1]	(29,737)	(37,022)	(22,862)
Other	16,531	4,998	12,965
Total natural gas operating revenue	$ 875,371	$ 850,748	$ 997,759
Number of customers served (average):			
Residential	782,413	772,130	761,010
Commercial firm	56,113	55,716	55,372
Industrial firm	2,304	2,308	2,330
Interruptible	367	393	398
Transportation	230	234	226
Total customers	841,427	830,781	819,336
Natural gas volumes, therms (thousands):			
Residential	605,313	571,265	621,915
Commercial firm	277,639	264,775	279,656
Industrial firm	22,915	23,890	25,500
Interruptible	45,176	47,275	49,249
Total retail natural gas volumes, therms	951,043	907,205	976,320
Transportation volumes	227,657	230,735	236,578
Total volumes	1,178,700	1,137,940	1,212,898

Natural gas conservation potential assessment (CPA)

PSE received feedback from Kyle Frankiewich (WUTC staff) concerning the the release of the draft CPA report and underlying CPA data for the natural gas IRP.

The draft CPA report will be included with the draft IRP filing on January 4, 2021. The CPA data used in the natural gas IRP is posted along with the Consultation Update in native file format as requested (MS Excel). The file is available on the IRP website.

Natural gas sensitivities

PSE received feedback from several stakeholders on their preferences for the natural gas sensitivities. These along with the response to the sensitivity survey from Webinar 9 will be used to develop the list of sensitivities.

Summary of all updates

PSE appreciates the feedback provided by stakeholders. In summary, the following changes will be implemented:

- PSE will post CPA data files on www.pse.com/irp and provide the draft CPA report as part of the 2021 IRP draft available on January 4, 2021.
- Based on the stakeholder feedback, PSE will analyze the following sensitivities for the natural gas IRP:

    21 - Use AR5 to model upstream emissions
    14 - 6-yr ramp rate
    17 - Social discount rate for DSR
    42 - Equity-focused portfolio

- PSE has also tentatively included the sensitivity number 16 titled Non-Energy Impacts in the list of ‘must-run’ sensitivities. The list of ‘must-run’ sensitivities for the Gas Portfolio is as follows:

    1 – Mid Economic Conditions
    2 – Low Economic Conditions
    3 – High Economic Conditions
    12 – Fuel Switching form gas to electric
    16 – Non-Energy Impacts
    31 – Temperature sensitivity on load

Webinar #9: Electric Portfolio Modeling Process, Final Power Prices, Electric Sensitivities, and Inputs and Observations from Draft Results

10/21/2020

Overview

On October 20, 2020 Puget Sound Energy hosted an online meeting with stakeholders to discuss the electric portfolio modeling process, final power prices, electric sensitivities, and inputs and observations from draft IRP results. Additionally, participants were able to ask questions and make comments using a chat box provided by the Go2Meeting platform.

Below is a report of the questions submitted to the chat box. Answers to the questions were provided verbally by IRP staff during the webinar. Please note that questions were answered in order of relevance to the topic currently being discussed. Questions regarding other topics were answered at the end of the webinar session.

To view a recording of the webinar and to hear responses from staff, please visit the project website at pse-irp.participate.online.

Attendees

A total of 54 stakeholders and PSE staff attended the webinar, plus another 8 attendees who called into the meeting and did not identify themselves (62 people total).

Attendees included: Anders Glader, Anne Newcomb, Ben Farrow, Bill Pascoe, Brian Fadie, Brian Grunkemeyer, Charlie Black, Charlie Inman, Chris Wissel-Tyson, Cody Duncan, Cory Kupersmith, Court Olson, Deborah Reynolds, Don Marsh, Doug Howell, Elyette Weinstein, Eric Fox, Fred Heutte, Graham Horn, James Adcock, Joni Bosh, Joshua Rubenstein, Kathi Scanlan, Katie Ware, Kevin Jones, Kyle Frankiewich, Larry Becker, Mark Tourangeau, Nate Sandvig, Robert Briggs, Stephanie Chase, Steven Griffith, Ted Drennan, Virginia Lohr, Wendy Gerlitz, and Willard Westre.

Questions Received

Questions from attendees are posted in the order in which they were received. The webinar began at 1:00 PM PDT and ended at 4:35 PM PDT.

Name	Time Sent	Comment
Alison Peters	**12:59 PM**	Welcome to the webinar. We're glad you're here.
Charlie Black	**1:06 PM**	Good afternonn. Which topics will be at "Inform" level and which topics will be at "Involve" level?
Deborah Reynolds	**1:07 PM**	Good afternoon, all
Elise Johnson	**1:10 PM**	Hi Charlie! In order of presentation: Electric Portfolio Model is inform; Electric IRP Process is inform; Electric Portfolio Sensitivities is involve
James Adcock	**1:14 PM**	Slide 11 "What does for PSE Only" mean?
James Adcock	**1:16 PM**	Slide 12 "Is the 'Hourly Dispatch Run' part of PSE's modeling efforts?"
Charlie Black	**1:17 PM**	I have a question about Slide 12.
Kathi Scanlan	**1:24 PM**	Slide 11: Thank you for the overview of the electric portfolio model process, including inputs. Would you please indicate which inputs are ready and any others that are still under development. When will these values be discussed with the advisory group, e.g. flexibility benefit
Fred Heutte	**1:33 PM**	Question on slide 18…
James Adcock	**1:38 PM**	+1 Fred
James Adcock	**1:40 PM**	Comment: PSE's idea of the "Real Market Conditions" is that the actual real market will never in the future include actual costing of SCGHG. I think that is a bad assumption, leading potentially to "stranded assets."
Anne Newcomb	**1:46 PM**	Yay!!!
James Adcock	**1:47 PM**	Slide 25 Raise Hand.
Doug Howell	**1:47 PM**	Slide 25 raised hand
Don Marsh	**1:49 PM**	Question on loss of load in summer. And summer forecast.
James Adcock	**1:51 PM**	Slide 29 Raise Hand.
Fred Heutte	**1:52 PM**	I have a comment about the ELCC assessment.
Kyle Frankiewich	**1:53 PM**	1:53 PM: slide 30: I don't understand EUE represented as a percentage, or, if the percentages are ELCC, I don't understand what EUE means in the column labels
Bill Pascoe	**1:54 PM**	Slides 28 & 30 raise hand
Doug Howell	**1:55 PM**	I'm off mute
Doug Howell	**1:55 PM**	The screen says I am off mute
James Adcock	**2:01 PM**	+1 Doug
Alison Peters	**2:08 PM**	Please mute your lines. We are getting some background noise.
Fred Heutte	**2:08 PM**	Here's the reference to the PG&E/SCE/SDG&E July 2020 submission to the California PUC on ELCC values of solar/wind/hybrid resources, based on work by Astrape Consulting: https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5868-E.pdf
Mark Tourangeau	**2:09 PM**	Wouldn't a stand alone storage resource have an even greater positive impact on ELCC when it can integrate multiple renewable resources and not be tied to a specific resource for charging for ITC purposes. Additionally, they can provide ancillary services and frequency response.

Fred Heutte	**2:11 PM**	In summary, Astrape's analysis using the SERVM model shows wind ELCC going from 33% to 58% when paired with storage for the BPA region. There isn't data for BPA for solar (not sure why), but for the other regions in California and the West, solar PV with tracking ELCC goes from single digit percentages to nearly 100% with associated storage.
Kyle Frankiewich	**2:14 PM**	slide 30: i believe pumped storage projects are being marketed in slices other than the full 500MW project; that is, PSE could purchase some smaller share of the project instead of the whole thing. Would adjusting the size of the proxy resource cause this analysis to change?
Joni Bosh	**2:19 PM**	Is this planning margin for 2027 higher than in the last IRP - I recall some margin around 18%? Slide 31
Joni Bosh	**2:24 PM**	Non-emitting and renewable have specific definitions in CETA and do not overlap. Can you clarify your terms on slide 33
Nate Sandvig	**2:31 PM**	I have a question
R. C. Olson	**2:33 PM**	Why is DSR not included in the load forecast on slide 36, and when will we see that included in a projected load.
Alison Peters	**2:33 PM**	A reminder to mute please. We are hearing a keyboard in the background.
James Adcock	**2:38 PM**	Comment: Yes meeting PSE's wind needs will take a lot of acreage, but comparing to the size of a major city like Seattle isn't very meaningful given that Washington State has about 850 times the acreage of say Seattle.
R. C. Olson	**2:39 PM**	So when will we see a real demand forecast that includes DSR?
James Adcock	**2:40 PM**	Comment re "storage" -- I don't understand why "storage" cannot be provided via contract with BPA, when "storage" is one of the products called out by federal law that BPA must make available to utilities, including IOUs.
Fred Heutte	**2:48 PM**	Comment: land requirements for wind and solar vary a lot depending on the specific locale, but let's assume 50 acres/MW for wind (with about a 1-2% surface utilization rate) and 8 acres/MW for solar (with a much higher utilization rate but some shared activities possible). For 2000 MW of capacity, that would require 100,000 acres for wind and 16,000 for solar. 100,000 acres is about 150 square miles, and the state of Washington is 71,000 sq mi. I don
Fred Heutte	**2:49 PM**	I don't think the raw amount of land is really the issue, more it's about the right balance between optimizing renewable energy facility placement and other economic, environmental and cultural risk factors.
James Adcock	**2:49 PM**	Yes I agree that wind farm placement is a difficult process to do "right."
Doug Howell	**2:50 PM**	Question on slide 43 - what is GWP factor assumption?
Kevin Jones	**2:50 PM**	Slide 42 - Are the High Impact SCGHG costs from the same document that contains the 2.5% discount SCGHG costs?
Doug Howell	**2:52 PM**	I am trying to clarify and I am no longer on mute but you cannot hear me. Can the organizers un-mute me?
Alison Peters	**2:53 PM**	When we stop again, Doug, we'll bring you off mute.
Elise Johnson	**2:54 PM**	Hi Doug, sorry about that. We are showing you as unmuted like you were before.

Fred Heutte	**2:54 PM**	Fred Heutte (NWEC) (to Everyone): 2:54 PM: On slide 43, NWEC continues to state that the upstream emissions rate is based on obsolete analysis, for both US and Canadian sources of natural gas. We have provided extensive documentation summarized in our parallel comment to the Northwest Power and Conservation Council at: https://www.nwcouncil.org/sites/default/files/2020_0616_2.pdf
Bill Westre	**2:56 PM**	S- 47 Where is MT wind shown
Bill Westre	**2:58 PM**	S-48 Please use 750 MW for MT instead of 565 - the Colstrip sale is not approved yet
Don Marsh	**2:58 PM**	S-49 question.
Kathi Scanlan	**2:58 PM**	Slide 49 - please read footnote, it's cutoff
Charlie Black	**2:59 PM**	On Slide 49, why are CCCTs only assumed to be available from within the PSE service area?
Alison Peters	**2:59 PM**	The footnote: *Not including the PSE IP Line (cross Cascades) or Kittitas area transmission which is fully subscribed
Fred Heutte	**3:00 PM**	Question about slide 49
Kyle Frankiewich	**3:00 PM**	slide 47: please describe the distributed solar resource option.
Bill Pascoe	**3:01 PM**	Slide 48 raise hand
Bill Westre	**3:01 PM**	Raise hand
Doug Howell	**3:04 PM**	Would you build a peaker outside of PSE service territory?
Fred Heutte	**3:06 PM**	PNNL annual capacity factor estimates for Oregon offshore wind range from 61% at Port Orford (south coast) to 49% even as far north as Astoria. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-29935.pdf
Doug Howell	**3:09 PM**	True. Litigation parties and public comment clearly shows opposition to PSE's sale of transmission
Fred Heutte	**3:19 PM**	Question on slide 52
Brian Grunkemeyer	**3:19 PM**	My understanding is CETA requires you to expand your DR capabilities. How are you modelling that in the IRP?
Kyle Frankiewich	**3:20 PM**	Brian is correct that PSE is required to acquire all cost-effective demand response. I share his concern that PSE's current consideration of demand response may not be sufficient.
Brian Grunkemeyer	**3:25 PM**	No, Demand Response
Doug Howell	**3:33 PM**	I ask for sensitivities for a ramp rate on conservation for both 6-years and 8-years. I am okay with you now dropping the 6-year ramp rate to make room for other sensitivities.
James Adcock	**3:33 PM**	Slide 60 raise hand.
Virginia Lohr	**3:34 PM**	When will we be able to discuss what it is the survey?

Robert Briggs	**3:39 PM**	This is a belated follow-up to discussion surrounding your treatment of social cost of carbon as a fixed cost. Perhaps there are semantic issues that are causing lingering confusion. When you are evaluating the smallest increment of an energy conservation resource in your optimization to decide whether to include it or not in the least-cost portfolio, is that measure evaluated against the cost of energy it saves or is it evaluated against the energy cost savings plus the avoided social cost of greenhouse gas emissions?
Virginia Lohr	**3:39 PM**	Please answer my question.
Kyle Frankiewich	**3:39 PM**	slide 59: i imagine some sensitivities will require more extensive modification of the modeling environment than others. Will the relative complexity of a given sensitivity be a part of PSE's decision-making process?
Elise Johnson	**3:40 PM**	Hi Virginia! We see your question and will get to it when we pause for questions.
Brian Grunkemeyer	**3:42 PM**	Slide 60 - Who cools their house to 65 degrees? Shouldn't you be using say 75 degrees for your CDD base?
Don Marsh	**3:42 PM**	Slide 60: question
James Adcock	**3:55 PM**	Slide 64 raise hand.
Anne Newcomb	**3:56 PM**	Someone is unmuted
Fred Heutte	**3:57 PM**	Comment on slide 66
James Adcock	**3:59 PM**	Slide 66 raise hand.
Kyle Frankiewich	**4:01 PM**	slide 67: please expand on the differences between the Council's study and itron's review
Brian Grunkemeyer	**4:02 PM**	(You can ignore my comment on slide 60)
Robert Briggs	**4:02 PM**	Have you evaluated which base temperature correlates best with PSE's aggregate load? I note that cooling degree hours at base 80°F is frequently use for residential space cooling loads.
Robert Briggs	**4:07 PM**	Comment: The reason why the NWPCC's method is likely the best choice is because most climate models suggest nonlinear responses to climate forcing.
Virginia Lohr	**4:09 PM**	For Sensitivity 22 on modeling federal carbon pricing, I compared the August spreadsheet to the new one so I could see how PSE had changed it based on public input. The new spreadsheet has a brief note on what I said, but it does not have a note that the person who is listed as asking for this sensitivity agreed with me. More alarming is that there is no change in what PSE is proposing to model. I looked at the survey this morning, and for sensitivity 22, it does not say what federal price you will use. I assume that the same has also been done for other sensitivities, but I haven't checked those. How can I and others know if we want to select this sensitivity without knowing what carbon pricing you will actually use?
Charlie Black	**4:11 PM**	Raise hand on carbon tax assumptions.
James Adcock	**4:20 PM**	Note my objection: PSE cuts me off almost immediately, but allows other to continue talking indefinitely.
Alison Peters	**4:20 PM**	Fair point, Jim. Thank you.
Alison Peters	**4:23 PM**	If you haven't had a chance to ask your question on the sensitivities, please type it into the chat so we can move it to the Feedback Report.

		Everything typed in will get a written response. Please identify things that are time sensitive so you can participate in the survey.
Don Marsh	**4:23 PM**	If I were concerned only with reliability, I would vote for NWPCC's model that increases by 0.9 degrees per decade. BUT that may cause huge impacts on COST and ENVIRONMENTAL IMACT. We must wisely choose to consider ratepayers, disadvantages groups, and the health of our planet. Therefore, I want to vote for accuracy, not over build based on inaccurate models. I can't tell if NWPCC is reasonable or not.
James Adcock	**4:25 PM**	+1 Fred's comments -- the changes in the climate of the coastal PNW *does not* look like the changes in the rest of the US, coastal PNW has *uniquely* experienced large increases in the temperatures, and hourly temperatures, of coldest winter days.
Virginia Lohr	**4:29 PM**	You currently cannot complete the survey to say what sensitivities you prefer without also selecting one of their 3 temperatures options.
R. C. Olson	**4:29 PM**	Have any of the analyses considered the increased use of air conditioning with air filtering to reduce the indoor air quality impact from forrest fire smoke?
James Adcock	**4:29 PM**	Re Market prices -- but PSE does not have a responsibility to "guarantee" the prices of the entire PNW, but rather *only* has a responsibility to their own ratepayers. Since Puget now has much more mild coldest-winter-day conditions -- a large change compared to other utilities, PSE should not have to "cover" for other utilities. PSE is responsible to reasonable to "cover" their own exposure to market -- but that is a "market" analysis -- it is no excuse for Puget to get their own modeling of climate change in the own region "wrong."
James Adcock	**4:30 PM**	Note my objection: PSE has frozen me out again.
Kyle Frankiewich	**4:31 PM**	What are the topical fact sheets?

PSE IRP Feedback Report
Webinar 9: CETA Assumptions, Demand Forecast, Resource Adequacy, Resource Need
October 20, 2020

11/3/2020

The following stakeholder input was gathered through the online Feedback Form, from October 13 through October 27, 2020. PSE's response to the feedback can be found in the far-right column. To understand how PSE incorporated this feedback into the 2021 IRP, read the Consultation Update, which will be released on November 10, 2020.

PSE appreciates the strong response to our stakeholder survey on sensitivity prioritization, we gathered over 140 individual responses. PSE is in the process of reviewing the information and what these selections mean for the IRP process. A summary will be provided for the November 10 Consultation Update.

Feedback Form Date	Stakeholder	Comment	PSE Response
10/19/20	James Adcock	Per your new stated requirements at the previous IRP meeting, I am hereby giving you a "heads up" asking you to "reserve time" to discuss and meaningfully answer technical questions on the following items below: Page 12 Robust technical discussion of the appropriateness of PSE including SCC in the first half of their modeling, but not in the second half of their modeling. Page 24-25, 30 Peak capacity need, etc. Robust technical discussion about what range of years of weather data PSE is using in modeling peak capacity need, and in PSE's modeling of LOLP, EUE, LOLH, LOLE, and LOLEV, and whether or not those range of years of "weather data" modeling are still appropriate or not, given the large effect of climate change on the items. In general discussion of issues of Peak Capacity Planning in the context of existing CETA law and Proposed CETA regulations in the follow section: UE-191023 OTS-2679.1 "PART VIII-PLANNING" WAC 480-100-620 (10) (b) at least one scenario modeling future climate change including changes to HDD and CDD. IE PSE would be required to stop using archaic pre-climate-change weather data from the 1930s through the 1950s in their modeling of peak capacity needs, and instead would need to include modeled future weather data including the effects of even more future climate change, with even lower "coldest winter day" expectations than the weather happening in the most recent two decades. Point of Order Question/Issue: At the previous IRP Meeting PSE represented that they had been answering my question in the Consultation Updates. I went back, again, and reread those Consultation Updates and PSE is not, in fact answering my questions, but rather generically lumping my name in with a bunch of other IRP participants who had questions, and then instead of answering anyone's questions is simply restating, in a kindergarten-level hand-wavy manner the material PSE already presented at the previous IRP meeting. I want an opportunity to correct the misrepresentation that PSE made about me at the previous meeting stating that PSE has been answering my questions in the Consultation Update, and that I simply had not been reading those answers. That representation PSE made about me in public at the previous IRP meeting is simply false, and I want to be able to correct that PSE misrepresentation made about me. James Adcock, electrical engineer	Thank you for using the Feedback Report system to help structure Webinar discussion. On July 21, PSE held a meeting on the role of the Social Cost of Greenhouse Gases (SCGHG) in the modeling process. Materials from that webinar and technical discussion can be found on the PSE IRP website at www.pse.com/irp. The Consultation Update for the July 21 Webinar is also available online. During the September 1 Webinar, the Resource Planning team defined how the peak capacity need, Loss of Load Probability (LOLP), Expected Unserved Energy (EUE), Loss of Load Hours (LOLH), Loss of Load Expectation (LOLE), and Loss of Load Events (LOLEV) would be defined. Materials from that webinar can be found on the PSE IRP website. PSE will be evaluating adjustments to the Heating Degree Day (HDD) and Cooling Degree Day (CDD) values in a temperature sensitivity in order to address concerns over which temperature years are used for IRP modeling. Thank you for your commentary on how PSE has been using the Feedback Report system. PSE groups questions by theme in Consultation Updates to streamline the document and reduce the amount of repeated information. Every effort is made to respond to every Feedback Form to best of PSE's ability.

Feedback Form Date	Stakeholder	Comment	PSE Response
10/20/2020	James Adcock	Note my objection: PSE has again, for 12 years running, deliberately "frozen out" my questions re PSE "weather modeling" now including their extremely small proposed changes due to "climate change." Puget said in so many words they would allow me to ask my questions at the end of the session, and then refused to do so. In contrast to what PSE is proposing, Seattle-area has had huge changes in "coldest winter days" especially coldest winter hours, and PSE's proposed (and not really explained) tiny changes in HDD do not capture what has actually happened already in terms of "coldest winter days" warming trends. I suggest again, that PSE simply use the most recent 20 years of actual weather data, which already is almost 60,000 hourly data points for the winter alone. I certainly would suggest in no cases whatsoever should PSE be using weather data prior to 1970, where that ancient weather data has no relevance -- in terms of coldest winter days -- to what the Puget Sound region is experiencing in recent decades. Finally I ask that Puget give much more detailed technical information about how they plan to use one of their "choice-of-three" minor changes and what range of years of actual historical data they plan to use to develop their (as shown in slide 64) "typical weather patterns." And I attach a log-histogram plot of the three most-recent 20-year periods in the PNW, using actual real weather data, showing how much "coldest winter days" have already increased in temperature, and showing, in comparison, average or median winter day temperatures have barely changed at all. But PSE wants to "correct" for those small average barely-changed winter day temperatures -- while completely ignore the huge changes, the huge warmings, in "coldest winter days" -- and those "coldest winter days" in turn determine PSE peak capacity needs. **Please see attached: James Adcock attachment feedback form dated October 20**	PSE will be evaluating adjustments to the HDD and CDD values in a temperature sensitivity analysis in order to address this concern. PSE will use the revised temperature forecast, discussed on slide 64 of the October 20 Webinar, to generate a 'temperature sensitivity demand forecast'. This demand forecast then flows into several components of the IRP model including demand for the portfolio model, the renewable need calculation and the resource adequacy model. One of the choices for this sensitivity is a 20-year trend. PSE also presented other choices, which included work by Itron, Inc. In this analysis, they found that the 23-degree peak used is well within the confidence interval.
10/21/2020	Willard Westre, Union of Concerned Scientists	Slide 48 PSE currently owns a 750MW share of the Colstrip Transmission line giving it access to Central and Eastern Montana. The proposed sale of Colstrip #4 includes transfer of 185 MW of that capacity to NWE, leaving 565 MW available to PSE with an option to lease back capacity from NWE. However, that sale has not yet been approved by the WUTC. In either case, PSE can have access to the full 750 MW of transmission capacity. 750 MW should be used in all further analyses if the performance advantage of Montana wind is to be fully and fairly evaluated. The 185MW difference is also the subject of a yet-to-be-selected scenario. Question: Will PSE use 750MW instead of 565MW in its Aurora and later analyses combined with the Firm Transmission Scenario even if the 185 MW Scenario is not selected and analyzed? If not why not?	Thank you for your comments. Given the recent change of status of the Colstrip Unit 4 sale, PSE will model 750 MW of transmission to the Colstrip region of Montana for all IRP modeling scenarios and sensitivities (i.e. 750 MW will be the base assumption for the IRP).
10/26/2020	Virginia Lohr, Vashon Climate Action Group	This comment is about the validity of PSE's Sensitivities Survey. I have experience with writing surveys for valid research. For the Sensitivities section of PSE's survey, people are given a choice of selecting between 1 and 10 options. This is appropriate, since not everyone may want to select 10 Sensitivities. If 10 were required, respondents might feel they had to select ones they did not understand or care about, so they might decide not to do the survey or they might select enough to get to 10 choices, and PSE would have no way of knowing which they actually were asking PSE to run or which ones were just to fulfill the requirement of reaching 10 responses. While the format selected for responding to Sensitivities seems appropriate, the information provided in the choices is not. For example, Sensitivity 22 says it will use a federal price on carbon, but does not say what that price PSE has settled on to use in the run. PSE received input on this Sensitivity in August from me about the proposed rate of $15 being low, and particularly, about the proposed rate of increase of only inflation being inappropriate. I mentioned two specific proposals as possible alternatives. No one opposed my suggestion. Even Vlad Gutman-Britten, the person who PSE had listed in the spreadsheet	Thank you for your comments. PSE has received your other feedback pertaining to sensitivity #22, stating that the federal carbon tax should be set to $15 per ton, then escalate $10 per ton per year plus an adjustment for inflation. PSE is currently vetting this recommendation against existing proposals for federal carbon taxation. PSE will confirm the final tax rate in the Consultation Update. PSE suggests that the spreadsheet provided was a means of portraying the intent of each sensitivity. PSE made the spreadsheet available to all stakeholders and reviewed it during the IRP Webinars. The many specific details necessary to actually model each sensitivity are impossible to include in such a summary document. The survey was written to extract as much stakeholder feedback as possible in an efficient, timely manner. Three temperature sensitivity options were offered by PSE as achievable for the 2021 IRP process given time

Feedback Form Date	Stakeholder	Comment	PSE Response
		as suggesting this option, agreed with me. PSE noted that I requested this change. At the Oct. 20 webinar, PSE said they were still consulting staff about what rates to use. To not have made that decision by now is unreasonable. People cannot make reasonable choices when they do not what those choices actually mean. The biggest problem with the survey is that it requires people to answer Questions 6 and 7. Skipping these questions is not an option. These questions have choices that artificially force people to select one of PSE's limited answers, because there are no options such as "other" with a chance to enter a reason. There is no reason to force all survey respondents to make a choice between biodiesel and hydrogen in Question 6, especially if they did not select Sensitivity 47 about using biodiesel and hydrogen. If people do not understand different ways to model temperature, there is no reason to force them in Question 7 to select among PSE's three options. If respondents do understand all three temperature options and think they are all invalid, they are still forced to select one, perhaps causing PSE to think erroneously that the respondents would be happy with the selected choice. The survey format PSE selected forces respondents to make choices on these questions if they want their Sensitivity choices to be recorded; PSE has no way to interpret responses on these questions or on the Sensitivities. For example, if respondents don't feel they know enough to answer these questions and don't want to bias answers to them, they may decide not to complete the survey, so PSE will not receive sensitivity choices from some people, which means PSE won't hear from as many stakeholders as they could have. If respondents instead decide to make up answers to Questions 6 and 7 so that their Sensitivity choices are recorded, PSE will get invalid answers, which means that the results from those questions will be worthless. The survey as written could invalidate all of the results. Responses to Questions 6 and 7, in particular, are meaningless, and PSE should simply delete them; PSE should not report them or use them to make any decisions. PSE certainly should avoid saying things such as, "Participants preferred we run the sensitivity with biodiesel over hydrogen" if biodiesel receives the most votes. It is not appropriate to say, "Stakeholders liked the Northwest Power and Conservation Council's climate model temperature assumption" even if everyone selected it. PSE has no idea why anyone checked any of those boxes. Responses on the Sensitivities should be considered preliminary and a meeting with participants at the IAP2 level of Involve should be scheduled before sensitivity runs are made. Details of what PSE is actually proposing to model should be presented and a reasonable and sufficient amount of time should be scheduled for stakeholders to ask questions and make suggestions. PSE's responses should not be silence or thanking us for our input. If PSE really is proposing to run stakeholder suggested sensitivities, then they should actually be what stakeholders have requested.	and resource constraints. PSE hoped to gain insight into which of these three sensitivities best aligned with stakeholder opinions and used the survey to collect this information. PSE was not looking for alternative responses. Many stakeholders have been very vocal in IRP meetings, feedback forms and e-mails to IRP staff requesting that PSE use a 20-year trend. PSE listened to stakeholders and included this as one of the options. In addition to this stakeholder request, PSE has hired a consulting firm, Itron, to perform a separate analysis on temperature and PSE also researched the work done by the Northwest Power and Conservation Council which was included as one of the options. Outcome of the survey will be shared in the November 10 Consultation Update. Results of the sensitivities will be available for stakeholder discussion at future Webinars.
10/27/2020	Willard Westre, Union of Concerned Scientists	Slide 28 Question 1 - What is meant by Perfect Capacity? In earlier IRP sessions PSE agreed to use seasonal capacity factor data concurrent with the seasonal peak load in its process. Surely, seasonal capacity factors should also be used in the RA analysis as well. This is critical to understanding how each resource responds to each season's potential loss of capacity. Question 2 – Will PSE use seasonal capacity factors in the RA analysis? The capacity factors seem to vary in the IRP process each time they are tabulated. Question 3 – What are the current sources for these values? Slides 28-30 The Resource Adequacy data and especially the Draft ELLC data seems to be greatly oversimplified compared with its importance in the overall analysis. Question 4 – Will the draft IRP contain all the relevant data for each resource including saturation curves, seasonal capacity factors, MWh outputs, MW needed, comparative results, etc. so that this phase of the analysis can be clearly understood and appreciated? Slide 47 Apparent error: the MT-East and Central resources are wind not solar. Slide 49 Apparent error: The MT-Central and MT-East values appear to be transposed.	Thank you for your feedback. PSE's responses from the numbers you provided are as follows: 1) PSE's resource adequacy model (RAM) performs a stochastic assessment of when resources are available under a variety of load and hydro conditions. All resources have availability constraints limiting their ability to meet peak need conditions (e.g. the wind isn't blowing or a thermal plant forced outage). Perfect Capacity is a modeling tool used to simplify the measurement of shortfall in the RAM, whereby an imaginary resource has 100% availability, all the time; so it can always meet the peak need. 2) Yes, hourly resource profiles are used within the Resource Adequacy model, so seasonality is inherent in the data. 3) This is the first time, during the 2021 IRP process, that ELCC values have been provided. ELCC (Effective Load Carrying Capability) differs from NCF (Net Capacity Factor), which has been presented several times of the 2021 IRP process. However, values do evolve over the IRP process and are subject to change as the modeling process is finalized, PSE recommends checking the most recently published material to keep up to date. The ELCC values published in the October 20 Webinar are DRAFT and will likely be revised prior to final publication.

Feedback Form Date	Stakeholder	Comment	PSE Response
			4) Yes, saturation curves will be presented at a later time. ELCC values, including saturation curves, are still being developed and refined. 5) Apologies for the typographic error on the slide, MT-East and MT-Central are wind resources, not solar resources. 6) The table on slide 49, is correct. The annual net capacity factors for MT-Central wind is 39.8% and MT-East wind is 44.3%.
10/27/2020	Katie Ware, Renewable Northwest	**Please see attachment: Renewable Northwest letter feedback form dated October 27**	Thank you for your feedback. PSE's responses from the numbers you provided are as follows: 1) PSE has questions about the specifics of this request. After further communication with Katie Ware and Renewable Northwest, a complete answer will be provided in the Consultation Update to be released on November 10. Please note that the ELCC values shown are draft. 2) The ELCC of solar increased from the 2019 IRP process. The calculation of ELCC depends on a lot of factors, such as the location, size, load, and methodology. PSE would caution against indiscriminant comparisons of ELCC values between different utilities because of the myriad of variables between utility resource portfolios, load shapes and geography. For example, a higher capacity usually comes with a lower ELCC in the saturation curves. For battery storage and pumped hydro storage, PSE uses the EUE as the criteria in the ELCC calculation, use of different resource adequacy metrics may result in different results. 3) PSE will be evaluating adjustments to the HDD and CDD values in a temperature sensitivity analysis in order to address this concern. PSE will use the revised temperature forecast, discussed on slide 64 of the October 20 Webinar, to generate a 'temperature sensitivity demand forecast'. PSE will also make appropriate adjustments to the resource adequacy analysis to reflect the temperature adjustments to load.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Questions and comments from presentation. Slide numbers may have differed between the .pdf posted and the one used in the webinar. Apologies if some of my slide numbers are off by one:	Thank you for your questions and recommendations. PSE inserted each item below along with PSE's responses.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 11: Thank you for the overview of the electric portfolio model process, including inputs. Please indicate which inputs are ready and any others that are still under development. When will these values be discussed with the advisory group, e.g. flexibility benefit?	Slide 11: PSE is still in the process of completing a QA/QC process and does not yet have a summary of all the inputs available. The following topics have been covered in past Webinars and the details are available through presentation materials and related reports and attachments. In addition to filing an updated schedule for the Work Plan, PSE uses the IRP website and regular stakeholder email communication to notify stakeholders of changes. The flexibility benefit analysis has been delayed and will be discussed during the December Webinar. Other upcoming topics include: Clean Energy Action Plan, Clean Energy Implementation Plan, Highly Impacted Communities and Vulnerable Populations Assessment, wholesale market risk, portfolio results and resource plan, and distribution and transmission plans.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 12: It appears that the SCC fixed cost additions for existing and generic thermal resources are calculated separately and included in the LTCE model run. Is this correct? What steps are taken to calculate these SCC fixed costs? If practicable, please describe these steps in a process map similar to that on slides 11 and 12, or augment slide 12 to include the steps taken to calculate the fixed cost SCC adders.	Slide 12: The SCGHG adder is calculated during the LTCE simulation. A dispatch forecast for each thermal resource is generated during the LTCE run as the optimizer assesses addition of new resources. The SCGHG is calculated from this dispatch forecast and is added to the lifetime cost of each thermal resource. This is the SCGHG adder, which incorporates realistic, economic dispatch of the thermal resource while incorporating the SCGHG into portfolio build decisions (resource planning). A description of the process is available in the July 21 presentation located on the PSE IRP website.
10/27/2020	Kyle Frankiewich, Washington Utilities and	Slide 14: What would happen if the SCGHG was included as an adjustment to the gas price forecast, as the company proposes to do with the natural gas line of business? This is likely substantively similar to including the SCGHG in dispatch, or may sidestep the company's concern with the SCC-in-dispatch approach by avoiding an hour-by-hour dispatch modeling approach. Is there an advantage to including	Slide 14: Adding the SCGHG to the fuel price would have a similar effect to calculating the SCGHG as a dispatch cost. Both cases would encourage the model to reduce the dispatch of thermal resources, which is not desirable, because the SCGHG is not a real cost, but a planning adder. A real-world dispatch is important for making sensible build decisions, which is the intended goal of the IRP. Applying the SCGHG to the fuel works

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<tr><th>Feedback Form Date</th><th>Stakeholder</th><th>Comment</th><th>PSE Response</th></tr>
<tr><td></td><td>Transportation Commission</td><td>SCGHG as a fuel cost adder? I presume this has been considered and discarded in favor of the other two approaches, and would appreciate an explanation for why.</td><td>for the natural gas portfolio because the model is purchasing fuel to meet demand; it is simply a commodity cost and the model is not dispatching any resources. Whereas in the electric portfolio, natural gas plants are dispatched based on fuel and market prices.</td></tr>
<tr><td>10/27/2020</td><td>Kyle Frankiewich, Washington Utilities and Transportation Commission</td><td>Slide 15: Looking back at historical actuals, what percentage of PSE's purchased power in a typical year comes from or through MidC? Does PSE purchase significant amounts of power from other parties? Does most of this power get wheeled to MidC, or can it be wheeled through BPA from point of interconnection? At what scale – both in scale of MWh and in temporal distance – does PSE transact with other directly interconnected BAs such as SnoPUD, SCL or Tacoma Power? I presume that any trading is done on a short-term or balancing basis, and it is reasonable to simplify the modeling by excluding PSE's neighbor BAs from long-term capacity planning, but want to confirm that this is the case.</td><td>Slide 15: Short-term wholesale energy purchases for 2019 is 23.7% of total energy supply and 26.9% in 2018. See the table below for Puget Sound Energy's electric supply resources and energy production for years ended December 31, 2019, and 2018 as reported in the company's 10-K filing. PSE purchases energy from a variety of entities at the Mid-C trading hub.
<table>
<tr><th></th><th colspan="4">Peak Power Resources At December 31,</th><th colspan="4">Energy Production At December 31,</th></tr>
<tr><th></th><th colspan="2">2019</th><th colspan="2">2018</th><th colspan="2">2019</th><th colspan="2">2018</th></tr>
<tr><th></th><th>MW</th><th>%</th><th>MW</th><th>%</th><th>MWh</th><th>%</th><th>MWh</th><th>%</th></tr>
<tr><td>Purchased resources:</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Columbia River PUD contracts[1]</td><td>687</td><td>14.5%</td><td>674</td><td>14.3%</td><td>2,642,177</td><td>10.2%</td><td>3,468,702</td><td>13.7%</td></tr>
<tr><td>Other hydroelectric</td><td>72</td><td>1.5</td><td>72</td><td>1.5</td><td>272,653</td><td>1.0</td><td>315,948</td><td>1.2</td></tr>
<tr><td>Other producers</td><td>285</td><td>6.0</td><td>284</td><td>6.2</td><td>3,276,502</td><td>12.7</td><td>3,406,627</td><td>13.6</td></tr>
<tr><td>Wind</td><td>56</td><td>1.2</td><td>56</td><td>1.2</td><td>123,368</td><td>0.5</td><td>131,270</td><td>0.5</td></tr>
<tr><td>Short-term wholesale energy purchases</td><td>N/A</td><td>—</td><td>N/A</td><td>N/A</td><td>6,144,663</td><td>23.7</td><td>6,822,927</td><td>26.9</td></tr>
<tr><td>Total purchased</td><td>1,100</td><td>23.2%</td><td>1,086</td><td>23.2%</td><td>12,459,363</td><td>48.1%</td><td>14,145,474</td><td>55.9%</td></tr>
<tr><td>Company-controlled resources:</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Hydroelectric</td><td>250</td><td>5.3%</td><td>250</td><td>5.3%</td><td>712,727</td><td>2.8%</td><td>914,540</td><td>3.6%</td></tr>
<tr><td>Coal[3]</td><td>677</td><td>14.3</td><td>677</td><td>14.4</td><td>4,347,639</td><td>16.8</td><td>4,184,950</td><td>16.5</td></tr>
<tr><td>Natural gas/oil</td><td>1,931</td><td>40.8</td><td>1,908</td><td>40.6</td><td>6,692,188</td><td>25.9</td><td>4,152,359</td><td>16.4</td></tr>
<tr><td>Wind</td><td>773</td><td>16.3</td><td>773</td><td>16.5</td><td>1,667,489</td><td>6.4</td><td>1,932,378</td><td>7.6</td></tr>
<tr><td>Other[2]</td><td>2</td><td>—</td><td>2</td><td>—</td><td>—</td><td>—</td><td>—</td><td>—</td></tr>
<tr><td>Total company-controlled</td><td>3,633</td><td>76.8%</td><td>3,610</td><td>76.8%</td><td>13,420,043</td><td>51.9%</td><td>11,184,227</td><td>44.1%</td></tr>
<tr><td>Total resources</td><td>4,733</td><td>100.0%</td><td>4,696</td><td>100.0%</td><td>25,879,406</td><td>100.0%</td><td>25,329,701</td><td>100.0%</td></tr>
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<tr><td>10/27/2020</td><td>Kyle Frankiewich, Washington Utilities and Transportation Commission</td><td>Slide 19: The modeled transmission limit and Mid-C market purchase price and availability assumptions must be validated for the resulting LTCE results to be valid. I look forward to hearing more about the company's consideration of the price and reliability risk inherent in market reliance. Will this be covered on the Dec 9 meeting?</td><td>Slide 19: PSE is actively researching its market reliance and the availability of resources at the Mid-C market. Draft results of this research will be discussed at a future Webinar.</td></tr>
<tr><td>10/27/2020</td><td>Kyle Frankiewich, Washington Utilities and Transportation Commission</td><td>Slide 20: One of the values brought by DR and EE is energy savings achieved during off-peak hours enables hydro resources to hold more water and potentially contribute more to peak events. This hydro 'storage' effect would support an increased capacity impact for EE and DR, though given PSE's relatively limited hydro resources, this impact may be small. Are PSE's analytical tools able to model this interactive effect? Are there limitations to PSE's owned hydro and long-term hydro contracts that would prevent PSE from "trading" energy for capacity? We understand this may be part of the company's RA analysis, or may be a part of the flexibility analysis which has been moved to the December meeting.</td><td>Slide 20: PSE's portfolio model includes a seasonal hydro availability forecast. Included in this hydro forecast are hourly upper and lower hydro shaping bounds, which are established by contractual and statutory limitations on PSE's hydro resources. Therefore the model does allow hydro resources to interact with other components of the portfolio such as DR and EE, but only to a limited degree.</td></tr>
<tr><td>10/27/2020</td><td>Kyle Frankiewich, Washington Utilities and</td><td>Slide 25: Why did the company choose to run its RA analysis focusing on the years 2027 and 2031? Slide 32 shows a substantial resource gap in 2026.</td><td>Slide 25 (1): CETA legislation states that the Clean Energy Action Plan (CEAP) must include a resource adequacy assessment. PSE elected to a conduct a 10-year resource adequacy study (October 2031 – September 2032) to fit the 10-year CEAP timeline. PSE has historically conducted a 5-year assessment as well, and elected to retain this date range as well (October 2027 – September 2028). The modeled year follows the hydro year and allows the full winter and summer seasons to stay intact for the analysis.</td></tr>
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Feedback Form Date	Stakeholder	Comment	PSE Response
	Transportation Commission		
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 25: I understand based on previous presentations that the RA analysis results described here are generated using hydro and temperature data stretching back 80+ years. Will the company's weather sensitivities include running the RA analysis with varying weather and hydro datasets? If yes, the table in slide 25 would be a useful way to understand the impact of any weather and hydro input variation. If no, why not?	Slide 25 (2): PSE will complete a temperature sensitivity, which will impact the demand forecast used in the resource adequacy model, and therefore the resource adequacy results. A similar table to that shown on slide 25 will accompany the sensitivity results.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 25: Does the RA model customize the load target to correlate with weather data? Put another way, is the RAM load forecast responsive to weather and hydro inputs?	Slide 25 (3): Loads are responsive to weather inputs. For the RA analysis 88 years of historic weather are run through the load model to create 88 years of load responses to temperatures. (These 88 load draws also include changes to the economic and demographic variables in the load model.) Loads are not sensitive to hydro conditions.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slides 25-26: While absent from the slides, the company shared that an update to the load forecast has resulted in some modeled loss-of-load events occurring during the summer. Please provide more information regarding this new modeled result. What changed within the load forecast that prompted increased load in the summer months? How will this reliability risk during the higher-priced summer peak months be reflected in the company's market reliance risk analysis? Would the company's adjustments to contemplate global warming likely increase the frequency of summer loss-of-load events?	Slides 25-26: The demand forecast shared in the October 20 Webinar is consistent with the demand forecast shown in the September 1 Webinar. However, an inconsistency with demand forecast dataset used for RA modeling was identified and aligned. PSE regrets that our comments in the meeting which only related to the RA data set gave the appearance that the demand forecast was changed. There are no changes in the demand forecast presented on September 1. Effects of market reliance will be analyzed as part of the forthcoming stochastic portfolio analysis. Effects of forecasted temperature will be analyzed as part of the forthcoming temperature sensitivity.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 30: DR resources share many similarities with energy storage. Has the company calculated an ELCC for any DR resources? Relatedly, is there an ELCC for energy efficiency, inclusive of the interactive effect with holding hydro? This interactive effect is not unique to energy efficiency, but perhaps most relevant for demand-side resources.	Slide 30: ELCC values will be calculated for all resources considered in the 2021 IRP. These values will be shared as they become available.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 31: How much of the planning margin includes contingency and balancing? With more renewables, the need for dispatchable resources may drive system need or planning margin increases more than load growth. Will this issue be explored in the context of the flexibility analysis or the resource adequacy analysis? Does PSE anticipate that the flexibility analysis may prompt specific resource acquisitions independent of the LTCE modeling, as is done at a smaller scale for must-take EE/DR/storage resources identified through distribution planning?	Slide 31: Contingency and balancing components of the planning margin are embedded within the Peak Capacity Need calculated using the RAM. Given the stochastic nature of this model, it is difficult to tease apart specific components of the Peak Capacity Need. Both contingency and balancing reserves are calculated for each hour and vary depending on resources and load. **<u>Operating Reserves</u>** North American Electric Reliability Council (NERC) standards require that utilities maintain "capacity reserves" in excess of end-use demand as a contingency in order to ensure continuous, reliable operation of the regional electric grid. PSE's operating agreements with the Northwest Power Pool, therefore, require the company to maintain two kinds of operating reserves: contingency reserves and regulating reserves. **Contingency Reserves.** In the event of an unplanned outage, NWPP members can call on the contingency reserves of other members to cover the resource loss during the 60 minutes following the outage event. The Federal Energy Regulatory Commission (FERC) approved a rule that affects the amount of contingency reserves PSE must carry – Bal-002-WECC-1 – which took effect on October 1, 2014. The rule requires PSE to carry reserve amounts equal to 3 percent of online generating resources (hydro, wind and thermal) plus 3 percent of load to meet contingency obligations. The terms "load" and "generation" in the rule refer to the total net load and all generation in PSE's Balancing Authority (BA). **Balancing and Regulating Reserves.** Utilities must also have sufficient reserves available to maintain system reliability within the operating hour; this includes frequency support, managing load and variable resource forecast error, and actual load and generation deviations. Balancing reserves do not provide the same kind of

Feedback Form Date	Stakeholder	Comment	PSE Response
			short-term, forced-outage reliability benefit as contingency reserves, which are triggered only when certain criteria are met. Balancing reserves must be resources with the ability to ramp up and down instantaneously as loads and resources fluctuate each hour. **Flexibility Benefit.** The flexibility benefit (or cost) is applied to all resources modeled in the IRP and therefore has an impact on resource build decisions; however, decisions are not made solely on the results of the flexibility analysis.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 33: Does "Conservation: codes and standards" mean solely C&S impacts identified as free / must-take resources in the CPA, or does the -775,387 MWh figure include any programmatic conservation acquisitions? To confirm, are these codes and standards strictly ones that are fully adopted and known, and do not include any prospective standards? Also, is "solar PV" the estimate for customer-acquired rooftop solar, or something different?	Slide 33 (1): The "Conservation: codes and standards, solar PV" is combination of savings from codes and standards that are on the books, no prospective codes and standards in consideration are included, and the solar PV is the customer-acquired and owned. Both are zero cost to the portfolio and are must take resources.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 33: Does the assumption of normal hydro and P50 output for wind and solar align with the Council's methodology?	Slide 33 (2): PSE's method for calculating renewable need is consistent with methodology set forth in RCW 19.285 the Energy Independence Act which establishes the Washington Renewable Portfolio Standard. PSE understands the Northwest Power and Conservation Council renewable need methodology may differ slightly to account for the many, varying RPS requirements in effect throughout the WECC.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 46: I'm glad to hear that PSE is planning its conservation bundling to get more granularity around the anticipated cost-effectiveness threshold. Many conservation measures are associated with new buildings, and new building starts often correlate with regional economic activity. What percentage of each conservation bundle is associated with new construction EEMs? Are there separate EE/DR supply curves for low / mid / high load forecast scenarios? How does PSE's handling of this interactive effect compare with NWPCC?	Slide 46 (1): The portion of the 20-year potential that is related to new construction is about 83 aMW or about 14%. The high demand forecast is about 9% higher than the mid demand forecast in the 20th year. Thus the impact from the creating a separate CPA based on the high demand forecast is in the range of 1.3%. With a high demand forecast, the 83 aMW in new construction related savings may be around 90 aMW, or an increase in the overall total potential of 1.25%. Similarly, the low demand forecast would result in 2.3% lower savings potential in the 20th year of analysis. These are well within the error range of the savings forecast.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 46: The DR programs explored here presumably have some start-up costs, some continued expenses that may or may not scale with the size of the program, and possibly a program start and end date. How does PSE model these costs? How long are these programs assumed to exist? Is there a reinvestment option selectable by PSE's LTCE model at a DR program's end-of-life? What ramp rates are assumed for each DR resource?	Slide 46 (2): The DR programs each have start-up costs and ongoing costs. Start-up costs will be incurred in the early years when the savings may not even be available, that relationship between the gap of start-up costs and start of savings, is maintained when the portfolio model delays the start date. These programs are assumed to have a 20 year life. The ramp rates assumptions are based on the program type and are embedded in the CPA. The CPA draft report is not ready for posting at this time and will be available along with the IRP draft on January 4, 2021.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 47: I appreciate the consideration of distributed solar as an option, but believe there are other DERs, and combinations of DERs, which could be competitive and should be considered in PSE's modeling. See recommendation below.	Slide 47: Please see the response to the WUTC recommendation for DERs below.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 48: I did not realize until this meeting that PSE uses the word "unconstrained" to mean "assuming zero cost Tx for any resources in this zone." Thank you for the clarification. This helps me understand the value of running the Tx tiers. DERs will likely have outsized value in a Tx-constrained model run. Please remind me – what kind of Tx costs are assigned to proxy resources in regions considered unconstrained in Tier 0? I presume that there are at least BPA wheeling costs, and there may be a limit to the amount of wheeling available. How is this handled in PSE's modeling?	Slide 48 (1): To clarify, "unconstrained" does not mean "zero cost". Unconstrained means there is no limit on the number of resources which may be built in that region. All resources include a Fixed Transmission Cost, which represents BPA's wheeling costs. These costs were discussed in the June 30 Webinar and are available for review in the presentation materials. Sensitivity analysis using Tiers 1, 2 and 3 are intended to help understand where potential transmission constraints may exist in the future. The Webinar recording is available here.

Feedback Form Date	Stakeholder	Comment	PSE Response
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 48: I second Participant Westre's comment that the MT wind Tx topography should reflect what is currently held by PSE, and should not reflect a sale that has not been approved. This assumption should be a part of the base case, rather than a one-off sensitivity.	Slide 48 (2): Given the recent change of status of the Colstrip Unit 4 sale, PSE will model 750 MW of transmission to the Colstrip region of MT for all IRP modeling scenarios and sensitivities (i.e. 750 MW will be the base assumption for the IRP).
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 49: It seems that PSE should have access to wind production data that would allow it to provide wind capacity factors unique to each of the four WA zones – West, Central, South and East. How different are the wind profiles for each of these zones?	Slide 49: Yes, it is likely the model may be sensitive to the various wind regimes present throughout Washington State. For the purposes of this IRP, PSE will continue to use the one generic Washington wind shape for eastern, southern and central Washington. This was presented at the June 30 Webinar that is available for review on the PSE IRP website. These resources may be considered in future IRPs, but time does not allow for development of unique wind shapes for the 2021 IRP.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 50: I'm glad to hear PSE is analyzing its load and resources at the subhourly level. I'm unclear – what will the results of this flexibility analysis look like? Is it a flexibility value adjustment? Does Plexos include total portfolio costs as an output?	Slide 50: The PLEXOS model is a production cost model, so PSE will evaluate the change in costs associated with adding new resources to the portfolio. If the cost decreases, then this will be a flexibility benefit and reflected in the portfolio model as a savings. The PLEXOS model will also output flexibility violations such as the count (number of events) and the size (MWh). We can then see the violations in the base portfolio and how those violations change when adding new resources to the portfolio.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 57-58: I imagine some sensitivities will require more extensive modification of the modeling environment than others. Will the relative complexity of a given sensitivity be a part of PSE's decision-making process? How does PSE intend to use the results of the sensitivities survey?	Slide 57-58: Yes, some sensitivities require more extensive modifications to the IRP models and this fact will be taken into consideration as sensitivity analyses are processed. However, the benefit to the overall IRP process (i.e. what can be learned from the analysis) is the most important factor in determining if the sensitivity will be completed. PSE is also giving extra weight to sensitivities in which stakeholders have shown increased interest. The survey is intended to measure stakeholder interest in the various sensitivities suggested throughout the 2021 IRP cycle. Given the finite amount of time and resources available to complete the IRP, some sensitivities analyses may not be completed.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 60: Some of Eric Fox's datapoints presented verbally, such as the results of the survey of what weather assumptions and climate changes adjustments are commonly used in the utility sector, would be useful as part of the written record. How are temperature trends translated into HDDs and CDDs?	Slide 60: The methodology and results of the Itron analysis, along with the survey information that Eric Fox referenced, will be provided in the written record as part of the IRP book. Daily temperatures are translated into HDDs and CDDs using the formulas on Slide 60 of the October 20 Webinar.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 66: This type of analysis is very useful, and the principles should be applicable to the natural peak day planning standard used in the gas IRP analysis as well. I would appreciate extending these tables as far back in time as the data allows, to help us understand any broader trends or patterns.	Slide 66: As was discussed in the October 14 Webinar, the gas planning standard is very different from the electric peak planning standard. This has to do with the long time, higher cost and increased safety concerns in the event of a gas outage. The planning standard for the natural gas portfolio is based on a cost/benefit analysis.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 68: This comparison of forecasts is a very useful pair of graphs. Thank you for putting these together. A similar comparison across these four approaches putting the modeling approach, data inputs for historical weather, and other inputs influencing these trend estimates such as assumed global carbon emissions, would also be quite helpful.	Slide 68: Thank you for the comment, PSE is working on pulling together this data and will include a full write up in the draft IRP report to be uploaded to www.pse.com/irp on January 4, 2021.
10/27/2020	Kyle Frankiewich, Washington	Slide n/a: How does PSE intend to use the results of the weather approach survey?	Slide n/a: The results of the temperature sensitivity survey question will be used to help parameterize the temperature sensitivity completed for the 2021 IRP. PSE intends to model the temperature forecast by the method selected by stakeholders through the survey, as described during the October 20 Webinar.

Feedback Form Date	Stakeholder	Comment	PSE Response
	Utilities and Transportation Commission		
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	CPA: I don't believe the company has shared the Conservation Potential Assessment for electric or gas resources. I understand that participants in the company's conservation-focused advisory group have also not yet seen the document or the underlying data. Please share this document and data (in native file format) with stakeholders by posting it on the IRP webpage, as was done for the 2019 progress report. To the extent any of these materials are considered commercially sensitive, the company may request confidential treatment. If PSE contends that the CPA should not be shared at this time, please explain why and set expectations for when stakeholders will be able to review the CPA. This would also help stakeholders understand how recent code and standard updates – for example, increasing building efficiency standards – are reflected in the modeling.	CPA: Detailed CPA results were shared in the July 14 Webinar and are available online. The CPA output conservation supply curve data for the gas and electric will be posted online soon. The CPA draft report is not ready for posting at this time and will be available along with the IRP draft on January 4, 2021. It will include a discussion of the codes and standards updates in the CPA.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Flexibility as Oct 20 public input meeting topic: I thought I had made a mistake in my notes, but later realized the topic of flexibility was removed from this IRP meeting agenda recently. The work plan on file with the commission still has the topic included for this meeting as of October 20. While stakeholders have been waiting to discuss flexibility for a while now, staff also appreciates that it would be difficult to present the flexibility analysis if that analysis is not substantively completed. Still, from a public participation perspective, setting expectations for stakeholders with as much notice as possible, and keeping folks informed when changes must be made, can only help to build trust between the company and participants.	Flexibility: PSE has filed an updated work plan with the WUTC on October 27, 2020, which detailed the altered presentation schedule. PSE makes every effort to adhere to schedules, but occasionally additional work may be required to present meaningful results to the public.
		Expanded analysis of hybrid renewable resources: Staff echoes Participant Heutte's recommendation to review recently published analyses of the value streams provided by hybrid wind+storage or solar+storage resources in the region, and to verify that the many costs and benefits of these resources are accurately reflected in PSE's modeling tools.	Hybrid Resources: PSE has reviewed the materials submitted by NWEC on hybrid resources. As such, PSE has included three hybrid resources in the 2012 IRP: WA solar + battery, WA wind + battery and MT wind + pumped hydro storage. Costs for these resources were aligned with NWEC expectations during the feedback process following the May 28 Webinar.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	DERs as resource option: RCW 19.280.030(h) requires "A forecast of distributed energy resources that may be installed by the utility's customers and an assessment of their effect on the utility's load and operations." If I recall correctly, PSE is including a forecast of customer-adopted solar as an adjustment to its load forecast, but other than that, the company is not engaging in a targeted exploration of the potential impact of DERs on PSE's system. Studies have been done showing the potential for DER programs to delivery positive outcomes for the utility, participating customers and non-participating customers. In addition, utilities in the northeast and in California have demonstrated that, for example, customer-sited small-scale storage can provide significant value to all. Given that conservation may be cost-effective at a $100+/MWh LCOE, it strains credulity to assume that no DER-based resource options might exist which could bring value to the system. Some of these resources are proposed as sensitivities in the survey – sensitivities 35, 41 and 46, for example. Does PSE contend that these resource options should not be considered within the base case and all sensitivities? If so, why?	DERs: PSE is modeling DERs in several capacities as explained throughout this 2021 IRP process. These capacities include: 1) Solar PV as reflected as a demand side resource (i.e. customer purchases solar modeled in the CPA). These details were presented in the July 14 Webinar. 2) Residential western Washington PV solar (rooftop) is included as a generic resource to the 2021 IRP and documented during the May 28 Webinar feedback process. 3) Targeted development of PSE acquired non-wires development including solar PV, batteries, demand response, energy efficiency and combined heat and power as discussed in August 11 Webinar. 4) Demand response programs were discussed in July 14 Webinar as part of the Demand Side Resources Webinar. 5) Batteries within PSE system as a generic resource are documented in the May 28 Webinar feedback process. Also, sensitivities with altered forecast cost curves for DERs and altered customer solar PV adoption are scheduled to be run for the 2021 IRP process.
10/27/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Feedback on electric sensitivities: While staff is interested in seeing the results of all proposed sensitivities, staff appreciates that there is a finite amount of analytical work that can be performed before the IRP must be filed, and that some scenarios will yield more compelling results than others. As we've mentioned before and above, some of these sensitivities would be appropriate for inclusion in the company's collection of standard assumptions.	Sensitivities: PSE intends to model as many sensitivities as possible for the 2021 IRP process. As results are developed, PSE will consider further alterations to the standard assumptions in future IRP cycles.

<table>
<tr><th>Feedback Form Date</th><th>Stakeholder</th><th>Comment</th><th>PSE Response</th></tr>
<tr><td>10/26/2020</td><td>Don Marsh, et al, CENSE</td><td>Dear IRP Team and Commission Staff,

A dozen stakeholders participating in the development of PSE's 2021 IRP were alarmed to learn that the company is seeing possible loss of load during summer peaks.

The attached letter asks for further information and disclosure of the summer peak demand forecast that is producing these risks to PSE's customers.

Sincerely,

Don Marsh

Please see attachment: Don Marsh letter feedback form dated October 26</td><td>Thank you for your comments and clarifying questions. Answers to your questions are provided below.

1) PSE is working on pulling the data together and a graphic of the 2021 IRP peak for both the summer and winter seasons. This graphic will be will be included in the IRP draft available at www.pse.com/irp on January 4, 2021. PSE realizes that its status as a winter peaking utility is relatively unique in the WECC region, and therefore performs all resource adequacy calculations for the entire year to take into consideration impacts of other regions on market conditions.
2) The resource adequacy assessment is conducted for two case years, 2027 and 2031. Loss of load events are observed in both test cases, however, there were only 3 events in the year 2027 and 4 events in 2031 were observed in summer over the 7040 simulations composed of 8760 hours per simulation. (see tables below)
3) The tables below shows the monthly loss of load hours across the 7040 simulations of the Resource Adequacy assessment. At most, 1 hour loss of load is observed in the 2031 case (amid 7040 simulations of 8760 hours each). A loss of load does not indicate the magnitude of the event.
4) PSE will perform a temperature sensitivity, which includes alterations to the Resource Adequacy Model (RAM) to examine the impact of increased summer loads.
5) The purpose of the IRP process is to assess various portfolio options to mitigate against forecast resource constrained conditions. Results of the IRP, in particular the temperature sensitivity, will be available for review in the draft IRP Report on January 4, 2021. Stakeholders will be able to provide feedback on the draft IRP throughout January.
<table>
<tr><th colspan="3">2027 Case</th></tr>
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<table>
<tr><th colspan="3">2031 Case</th></tr>
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<tr><td>12</td><td>305</td><td>148</td></tr>
</table></td></tr>
<tr><td>10/27/2020</td><td>Don Marsh, CENSE</td><td>Dear IRP Team,

Please see the attached letter expressing concerns by stakeholders and participants in PSE's Sensitivity Survey. We object to the forced choice among three flawed sensitivity options. We suggest a different method that corrects these flaws and more accurately models changing temperatures in our region.

Please see attachment: Don Marsh letter feedback form dated October 27</td><td>Thank you for your feedback. PSE is in the process of reviewing the proposed temperature sensitivity methodology documented in your letter. PSE needs more time to evaluate an appropriate course of action. A response will be included in the November 10 Consultation Update.</td></tr>
<tr><td>10/27/2020</td><td>Brian Fadie, NW Energy Coalition</td><td>Please see attachment: NWEC letter feedback form dated October 27</td><td>Thank you for your comments. PSE's responses are summarized below.</td></tr>
</table>

Feedback Form Date	Stakeholder	Comment	PSE Response
			• Given the recent change of status of the Colstrip Unit 4 sale, PSE will model 750 MW of transmission to the Colstrip region of Montana for all IRP modeling scenarios and sensitivities (i.e. 750 MW will be the base assumption for the IRP). • In sensitivity #20 - Mid economic conditions with SCGHG as a dispatch cost in electric prices and portfolio model - the SCGHG will be calculated as variable cost for all emitting resources. The SCGHG is also included in the electric price forecast (as a tax) so the SCGHG will be included in the power price forecast and therefore also be present in market purchases. • In PSE's IRP model, market sales are limited to the transmission capacity available between PSE and the Mid-C Market. Social cost of greenhouse gas costs are included as an adder to market purchases, but not included as adders to market sales since it is possible to sell the power outside of Washington State.
10/29/2020	Nate Sandvig	**Please see attachment:** **Rye Development letter feedback form dated October 29**	Thank you for your comments. PSE's responses are summarized below. • ELCC values should be expected year to year. PSE updates many portfolio assumptions in the Resource Adequacy Model including but not limited to resource and contract changes, load forecast and regional market assumptions. These changes can result in significant changes in ELCC year to year. The ELCCs provided in the October 20 Webinar are still draft and expected to be updated. However, PSE will evaluate both battery and pumped hydro storage at 100 MW nameplate capacity to reduce the impact of saturation effects on large scale PHES. • PSE values the input of its stakeholders and has such provided a venue for stakeholders to voice which sensitivities they feel are important to the IRP process. PSE also recognizes that the IRP fulfills important regulatory requirements and that certain analyses are essential to meet these requirements. PSE places the highest importance on these analyses to ensure the IRP accomplishes its numerous objectives. • PSE acknowledges that one of the limitations of renewable generation (particularly wind and solar resources) is land-use consideration. PSE has not imposed any land-use-based build limitation into the 2021 IRP model; but aims to include such constraints in future IRP cycles.
Questions from the Webinar requiring follow-up			
10/20/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 30: I believe pumped storage projects are being marketed in slices other than the full 500MW project; that is, PSE could purchase some smaller share of the project instead of the whole thing. Would adjusting the size of the proxy resource cause this analysis to change?	For the 2021 IRP, PSE will evaluate both battery and pumped hydro storage at 100 MW nameplate capacity to reduce the impact of saturation effects on large scale pumped hydro storage.
10/20/2020	Robert Briggs	When you are evaluating the smallest increment of an energy conservation resource in your optimization to decide whether to include it or not in the least-cost portfolio, is that measure evaluated against the cost of energy it saves or is it evaluated against the energy cost savings plus the avoided social cost of greenhouse gas emissions?	The social cost of greenhouse is included as a cost adder to thermal resources and market purchases. All resources including non-emitting and renewable resources, thermal plants, and conservation, are evaluated for their total resource value and compared to other resources. For the thermal plants, the resource cost is increased for the SCGHG.
10/20/2020	Robert Briggs	Have you evaluated which base temperature correlates best with PSE's aggregate load? I note that cooling degree hours at base 80°F is frequently use for residential space cooling loads.	We model temperature sensitivity at the class level, not at the system level. The modelling for the weather sensitivities classes uses one or more base temperatures for calculating heating degree days (HDDs). Some classes use one or more base temperatures for calculating cooling degree days (CDDs). The calculation of HDD65 and CDD65 was shown for illustrative purposes. We take a class based approach because classes like the commercial class may cool their buildings to a lower temperature than residential customers.

Feedback Form Date	Stakeholder	Comment	PSE Response
10/20/2020	Virginia Lohr, Vashon Climate Action Group	For Sensitivity 22 on modeling federal carbon pricing, I compared the August spreadsheet to the new one so I could see how PSE had changed it based on public input. The new spreadsheet has a brief note on what I said, but it does not have a note that the person who is listed as asking for this sensitivity agreed with me. More alarming is that there is no change in what PSE is proposing to model. I looked at the survey this morning, and for sensitivity 22, it does not say what federal price you will use. I assume that the same has also been done for other sensitivities, but I haven't checked those. How can I and others know if we want to select this sensitivity without knowing what carbon pricing you will actually use?	PSE suggests that the spreadsheet provided was a means of portraying the intent of each sensitivity. The many specific details necessary to actually model each sensitivity are impossible to include in such a summary document.
10/20/2020	Court Olson	Have any of the analyses considered the increased use of air conditioning with air filtering to reduce the indoor air quality impact from forest fire smoke?	The peak demand forecast assumes an A/C saturation path, but PSE is not running any explicit sensitivities on an increased A/C saturation. That said, the base demand forecast is derived from and calibrated to recent seasonal history. This means we are capturing the current level of air purification demand in our usage models (to the extent of the last few years), but it is not modeled as an explicit end use with a particular trended saturation path.
10/20/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	What are the topical fact sheets?	A topical fact sheet is an International Association for Public Participation (IAP2) tool that provides a description of a project, and in PSE's case, made available on the web. When developing the public participation plan, PSE intended to use topical fact sheets as a way to distribute information to stakeholders. However, to date, PSE has not distributed any topical fact sheets.

PSE IRP Consultation Update
Webinar 9: CETA Assumptions, Demand Forecast, Resource Adequacy, Resource Need
October 20, 2020

11/10/2020

The following consultation update is the result of stakeholder suggestions gathered through an online Feedback Form, collected between October 13 and October 27, 2020 and summarized in the November 3 Feedback Report. The report themes have been summarized and along with a response to the suggestions that have been implemented. If a suggestion was not implemented, the reason is provided.

PSE thanks Kare Ware and Sashwat Roy (Renewable Northwest) for follow-up discussions concerning the loss of load probability question on November 6, 2020.

Temperature trends and temperature sensitivity

PSE received feedback from James Adcock, Katie Ware (Renewable Northwest), Kyle Frankiewich (WUTC Staff) and Don Marsh (CENSE) regarding the temperature years used to model PSE's load forecast and in the resource adequacy model. Stakeholders suggest that more recent temperature data (i.e. most recent 20 years) should be used to inform PSE models to limit the impact of colder weather observed in older records and accentuate warming trends present in more recent records.

PSE has committed to completing a temperature sensitivity for the 2021 IRP which will address the concerns raised by stakeholders. PSE has proposed three options for modeling temperature data for the temperature sensitivity:

1. Trended normal based on historical observed trends (trended normal analysis completed by Itron Inc.)
2. Temperature normal based on most recent 15 years of temperature data
3. Northwest Power and Conservation Council's climate model temperature assumption

More information on these options is available for review in the October 20 Webinar presentation. A stakeholder survey was conducted between October 19 and October 27 to collect feedback on which temperature option was of greatest interest. The results of the survey indicate the stakeholders suggest using the Northwest Power and Conservation Council ("NPCC" or "the Council") climate model temperature assumption (option 3). The full results of the survey are presented below.

Don Marsh and a group of stakeholders also prepared and presented an additional temperature sensitivity methodology as part of the feedback process. During this IRP process, many stakeholders provided recommendations in IRP meetings, feedback forms and e-mails to IRP staff requesting that PSE use the most recent 15 or 20-years of temperature data. PSE listened to stakeholders and included the most recent 15 years of temperature data as one of the options for stakeholder consideration. In addition to this stakeholder request, PSE has hired a consulting firm, Itron, to perform a separate temperature analysis and PSE also researched the work done by the Council on climate change modeling. Both of these analyses were included as additional options for temperature sensitivity analysis during the October 20 Webinar and in the sensitivity survey. Over 140 stakeholders responded to the sensitivity survey and 93 stakeholders selected the Council's climate change model temperature assumptions. PSE will follow the stakeholders' recommendation to use the Council's climate change model tempertuare assumptions and will consider the materials presented by Don Marsh et al for future IRP cycles.

The Northwest Power Conservation Council (the "Council") is using global climate models that are downscaled to forecast temperatures for many locations within the Pacific Northwest. PSE has chosen to look at one of these models. The Council weighs temperatures by population from metropolitan regions throughout the Northwest. However, PSE received data from the Council that is representative of SeaTac airport. This data is, therefore, consistent with how PSE plans for its service area and this data is not mixed with temperatures from Idaho, Oregon or Eastern Washington. The climate model data provided by the Council is hourly data from 2020 through 2049. This data resembles a weather pattern where the temperatures fluctuate over time, but generally trend upward. For the load forecast portion of the temperature sensitivity, PSE proposes to smooth out the fluctuations in the temperatures and increase the heating degree days (HDDs) and cooling degree days (CDDs) over time at 0.9 degrees/decade, which is the rate of temperature increase found in the Council's climate model.

Montana transmission capacity

PSE received feedback from Willard Westre (Union of Concerned Scientists), Kyle Frankiewich (WUTC Staff) and Brian Fadie (Northwest Energy Coalition) concerning the transmission capacity between PSE service territory and the Colstrip region of Montana. In the June 30 Webinar, and again in the October 20 Webinar, PSE presented an upper transmission capacity limit of 565 MW to Montana. At the time these values represented the most-likely transmission capacity available to PSE in the region. Since the presentation of these materials, negotiations for sale of PSE's portion of Colstrip Unit 4 have ceased. Therefore, PSE will model 750 MW of available transmission capacity to Montana for the 2021 IRP process as the base assumption.

PSE has also proposed modeling of several transmission constrained sensitivities for the 2021 IRP process. These sensitivities are structured around transmission tiers, which represent uncertainty of availability of transmission capacity. The change in Montana transmission capacity will influence BPA transmission redirect assumptions for the Eastern Washington region. These changes are summarized in the table below.

Resource Group Region	Added Transmission (MW) Tier 0	Tier 1	Tier 2	Tier 3
PSE territory (a)	(b)	(b)	(b)	(b)
Eastern Washington	Unconstrained	300	675	~~1,515~~ 1,330
Central Washington	Unconstrained	250	625	875
Western Washington	Unconstrained	0	100	635
Southern Washington/Gorge	Unconstrained	150	705	1,015
Montana	~~565~~ 750	350	565	~~565~~ 750
Idaho / Wyoming	600	0	400	600
TOTAL	generally unconstrained	1,050	3,070	5,205

(a) Not including the PSE IP Line (cross Cascades) or Kittitas area transmission which is fully subscribed
(b) Not constrained in resource model, assumes adequate PSE transmission capacity to serve future load

Sensitivity survey and selection

PSE received questions from Virginia Lohr (Vashon Climate Action Group), Kyle Frankiewich (WUTC Staff) and Nate Sandvig (Rye Development) concerning how the sensitivity prioritization survey would be used. PSE considers the sensitivity survey a tool to help collect stakeholder sentiment on each of the many sensitivities purposed over the course of the 2021 IRP process. PSE intends to use the results as a guideline for prioritizing which sensitivities to run as part of the IRP modeling process. Other factors such as difficulty, length of time and value to the entire IRP process will also be considered as sensitivities are processed.

The full results of the survey are provided below.

ELCC values

PSE received feedback from Willard Westre (Union of Concerned Scientists), Katie Ware (Renewable Northwest), Kyle Frankiewich (WUTC Staff) and Nate Sandvig (Rye Development) concerning the ELCC values presented in the October 20 Webinar. As PSE indicated during the webinar, the ELCC values presented are draft and subject to change over the course of the IRP modeling process. Furthermore, more refined values, including saturation curves, will be provided at a later date.

Specific concerns on the relative value of battery energy storage systems to pumped hydroelectric storage will be addressed with publication of ELCC values for both resources at a nameplate of 100 MW at a later date.

Summer loss of load events

PSE received feedback from Katie Ware (Renewable Northwest), Kyle Frankiewich (WUTC Staff) and Don Marsh (CENSE) concerning summer loss of load events. PSE would like to clarify that the demand forecast for the 2021 IRP process has not changed since its presentation during the September 1 Webinar. However, an inconsistency with the demand forecast dataset used for Resource Adequacy modeling was identified and aligned. PSE regrets that our comments in the meeting, which only related to the Resource Adequacy dataset, gave the appearance that the demand forecast was changed.

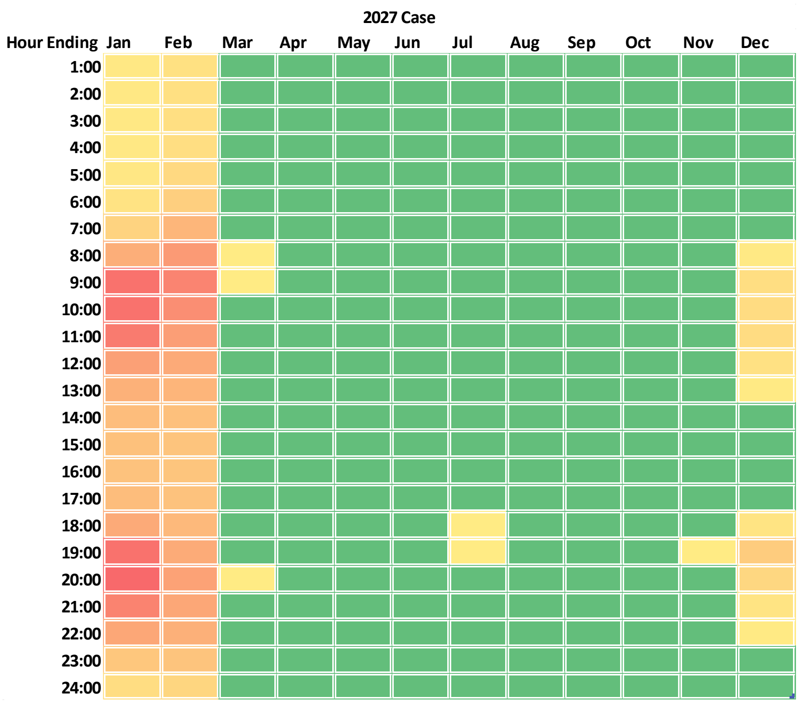
The summer-time loss of load events discussed during the meeting represent a very small fraction of the total loss of load events encountered over the course of a full year as shown in the tables below for the two test case years 2027 and 2031. A loss of load event can be caused by many factors which include temperature, demand, hydro conditions, plant forced outages, and variation in wind and solar generation. All of the factors are modeled as stochastic inputs simulated for 7,040 iterations. As mentioned previously, the data shared at the October 20 webinar are draft. PSE has been reviewing the data used for the resource adequacy model and found an inconsistency with the correlations for wind and solar data. PSE has fixed the correlations and is working on updating the peak capacity need and effective load carrying capability (ELCC) values. The table below has been updated since the November 3 feedback report to include the updates to the wind and solar correlations.

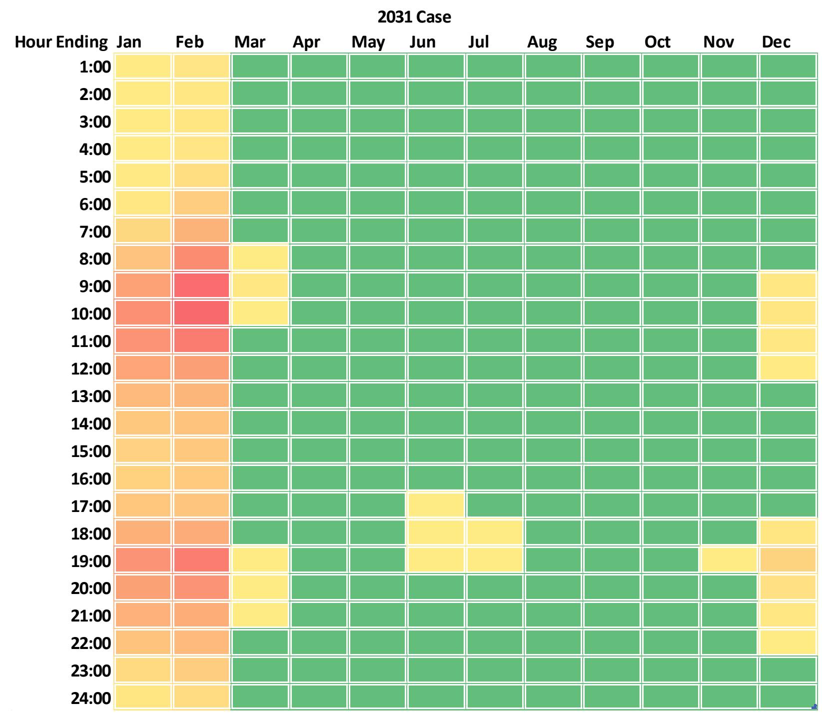
2027 Case		
Month	Loss of Load (h) base	Loss of Load (h) at 5% LOLP
1	4846	2893
2	3296	2553
3	10	5
4	0	0
5	0	0
6	10	0
7	3	2
8	0	0
9	0	0
10	0	0
11	5	1
12	474	275

2031 Case		
Month	Loss of Load (h) base	Loss of Load (h) at 5% LOLP
1	3860	2387
2	4267	3365
3	40	14
4	0	0
5	0	0
6	12	5
7	4	2
8	4	0
9	0	0
10	0	0
11	9	1
12	325	160

Notes: Tables represent the results of 7,040 simulations where each simulation is composed of 8760 operating hours. Tables do not describe the magnitude of any loss of load event, just that the event occurred.

Katie Ware (Renewable Northwest) had also requested a 12x24 of the loss of load probability as part of this feedback cycle. Given the methodology of the Resource Adequacy Model, PSE is not able to produce hour by hour probabilities, so instead these plots represent a relative heat map of the number hours of lost load binned by month and hour of day.





Sensitivity prioritization survey results

Thank you for your active engagement in the IRP process, PSE collected results from over 140 individual respondents with this survey.

Sensitivity Selection Results

Rank	Sensitivity Number and Description	Number of Responses
1	35 - EV battery to grid – stakeholder requested, webinar - models inclusion of an electric vehicle-to-grid resource as a generic resource	132
2	21 - Use AR5 to model upstream emissions – social cost of greenhouse gases / CO2 price – upstream emissions will be quantified using the AR5 methodology rather than the AR4 methodology	129
3	14 - 6-yr ramp rate – conservation – reduces the conservation measures ramp from 10 years to 6 years	126
4	32 - Add 185 MW Colstrip Transmission – stakeholder requested, webinar - models additional transmission from the Colstrip substation to PSE service territory	126
5	17 - Social discount rate for DSR – conservation – reduces the discount rate of demand side resources from 6.8% to 2.5%	124
6	39 - SCGHG only (dispatch cost) – stakeholder requested, webinar - models the social cost of greenhouse gases as a dispatch cost in the absence of other CETA targets	122
7	36 - Time of use pricing – stakeholder requested, webinar - models inclusion of time of use pricing for conservation and demand response programs	121
8	41 - Private solar input testing – stakeholder requested, feedback form – models inclusion of subsidy for solar and electric storage resources	121
9	42 - Equity-focused portfolio - stakeholder requested, feedback form – a minimum of 50% of new resources must be located in WA State and expansion of community solar programs	120
10	46 - Virtual Power Plants (VPP) – stakeholder requested, feedback form – VPPs are used to manage distributed energy resources	116
11	26 - 100% renewable resources by 2030, no gas generation – emissions reduction – models more aggressive renewable resource adoption and all gas plants would be retired by 2030	24
12	28 - Carbon reduction – emissions reduction – all natural gas plants retired by 2045 and run-time limits imposed to meet carbon emission targets	22
13	18 - High SCGHG – social cost of greenhouse gasesgreen house gases / CO2 price – models a higher social cost of greenhouse gases than specified by CETA	18
14	9 - "Highly Distributed" Transmission/build constraints, Tier 1 – transmission constraints / build limits - models a significantly transmission constrained system	17
15	11 - "Highly Centralized" Transmission/build constraints, Tier 3 – transmission constraints / build limits - models a lightly transmission constrained system	13
16	12 - Transmission/build constraints - time delayed (option 2) – transmission constraints / build limits - models an expanding transmission system over time	13
17	47 - Alternative fuel #2 for peakers – stakeholder requested, feedback form – a must-run sensitivity of either biodiesel OR hydrogen as an alternative fuel for peaker plants will be modeled, this sensitivity is a vote to model BOTH biodiesel and hydrogen as sensitivities	13
18	20 - Mid economic conditions with SCGHG as dispatch cost in electric prices and portfolio model – social cost of greenhouse gases / CO2 price – models the social cost of greenhouse gases as dispatch cost in both the power price and portfolio models	12
19	33 - Fuel switching from electric to gas – stakeholder requested, webinar - decreases demand in electric portfolio and increases demand in gas portfolio	12
20	5 - Mid economic conditions plus Increased Renewable Build – economic conditions - power price forecast adjusted to model 100% renewable energy goal in Oregon	11
21	16 - Non-Energy Impacts (NEI) – conservation – increases the value of non-energy impacts from adoption of conservation and demand response measures	11
22	24 - SCGHG as a tax in WA, OR, CA – social cost of greenhouse gases / CO2 price – models the social cost of greenhouse gases plus a regional CO2 tax of $15/ton (adjusted for inflation over time) in WA, OR and CA	10
23	37 - Holistic conservation approach – stakeholder requested, webinar - additional information needed to complete this sensitivity	10
24	22 - Mid economic conditions with SCGHG as a fixed cost plus a federal CO2 tax – social cost of greenhouse gases / CO2 price – models the social cost of greenhouse gases plus a federal CO2 tax	8
25	6 - Low demand with mid gas prices – economic conditions – low demand in both power price and demand forecasts and "most-likely" gas price forecast	6
26	15 - 8-yr ramp rate – conservation – reduces the conservation measures ramp from 10 years to 8 years	6
27	44 - 2% Cost threshold - stakeholder requested, feedback form – must take DR and Battery storage first, then optimized other builds – other stakeholder requested - resource additions are constrained to the CETA 2% cost cap, must build demand response and battery storage before gas plants	6
28	4 - Low Demand with a Very High Gas price – economic conditions – mix of low demand and very high gas price forecasts	5
29	45 - 2% cost threshold, renewable Over-generation Test – stakeholder requested, feedback form – resource additions are constrained to the CETA 2% cost cap, PSE market sales are prohibited	5
30	23 - High economic conditions with SCGHG as dispatch cost in electric prices and portfolio model – social cost of greenhouse gases / CO2 price – models the social cost of greenhouse gases as dispatch cost with higher than expected power price, demand and gas price forecasts	2
31	34 - High economic conditions with SCGHG as dispatch cost in portfolio model only – stakeholder requested, webinar - models social cost of greenhouse gases as a dispatch cost under higher than expected power price, demand and gas price forecasts	2
32	40 - Tweaks to resource cost assumptions – stakeholder requested, feedback form – models altered resource cost assumptions on generic resources (further detail forthcoming from WUTC staff)	2

Sensitivity #25 Alternative fuel #1, fuel selection

Rank	Alternate Fuel	Number of Responses
1	Hydrogen	140
2	Biodiesel	16

Sensitivity #31 Temperature sensitivity, temperature methodology

Rank	Temperature Methodology	Number of Responses
1	3. Northwest Power and Conservation Council's climate model temperature assumption	93
2	2. Temperature normal based on most recent 15 years of temerpature data	43
3	1. Trended normal based on historical observed trends (trended normal analysis completed by Itron Inc.)	20

Summary of all updates

PSE appreciates the feedback provided by stakeholders. In summary, the following changes will be implemented:

- The temperature sensitivity will be modeled using the Council's methodology.
- The Montana transmission capacity will be set to 750 MW.
- Sensitivity prioritization has been informed by the stakeholder survey results, as shown above.
- Hydrogen will be included as an alternate fuel choice in the Alternative Fuel #1 sensitivity (sensitivity #25, must-run).

Webinar #10: Clean Energy Action Plan and Clean Energy Implementation Plan, Economic, Health and Environmental Benefits Assessment of Current Conditions and delivery system and grid modernization needs

11/17/2020

Overview

On November 16, 2020 Puget Sound Energy hosted an online meeting with stakeholders to discuss the Clean Energy Action Plan and Clean Energy Implementation Plan, Economic, Health and Environmental Benefits Assessment of Current Conditions and delivery system and grid modernization needs. Additionally, participants were able to ask questions and make comments using a chat box provided by the Go2Meeting platform.

Below is a report of the questions submitted to the chat box. Answers to the questions were provided verbally by IRP staff during the webinar. Please note that questions were answered in order of relevance to the topic currently being discussed. Questions regarding other topics were answered at the end of the webinar session.

To view a recording of the webinar and to hear responses from staff, please visit the project website at pse-irp.participate.online.

Attendees

A total of 75 stakeholders and PSE staff attended the webinar, plus another 6 attendees who called into the meeting and did not identify themselves (81 people total).

Attendees included: Allison Jacobs, Andrew Wood, Anne Newcomb, Anthony O'Rourke, Ben Farrow, Bill Pascoe, Bill Westre, Bob Stolaski, Brett Rendina, Brian Tyson, Brian Grunkemeyer, Chad Ihrig, Charlie Black, Charlie Inman, Cindy Song, Colin Crowley, Cress Wakefield, Cuong Nguyen, David Meyer, Diann Strom, Don Marsh, Doug Howell, Elaine Markham, Elyette Weinstein, Eric Kang, Fred Heutte, Gurvinder Singh, James Adcock, Jennifer Snyder, Jens Nedrud, Jon Piliaris, Joni Bosh, Kara Durbin, Kathi Scanlan, Katie Ware, Kendra White, Kevin Jones, Kristina Kelly, Kyle Frankiewich, Leslie Almond, Lori Elworth, Marcus Sellers-Vaughn, Mariel Thuraisngham, Norm Hansen, Warren Halverson, Peter Brown, Rahul Venkatesh, Scott Williams, Shay Bauman, Sheri Maynard, Stephanie Chase, Ted Drennan, Thad Curtz, Therese Miranda-Blackney, Tom Eckman, Tyler Tobin, Vlad Gutman-Britten, Virginia Lohr, Wendy Gerlitz, and Wiemin Dang.

Questions Received

Questions from attendees are posted in the order in which they were received. The webinar began at 1:00 PM PDT and ended at 3:48 PM PDT.

Name	Time Sent	Comment
James Adcock	**1:11 PM**	Comment: I express concerns about the big elements which will not be ready in time for the Draft IRP, which I believe will keep participants from commenting in an informed manner on that Draft.
Don Marsh	**1:13 PM**	The Draft IRP should contain all the parts that stakeholders would want to participate and comment on. If the analysis is not available, the Draft IRP should be delayed until they are.
Kevin Jones	**1:14 PM**	The current CETA Rules call for UTC review only of DRAFT IRP's, which PSE is now telling us will be incomplete on their filing date. Will PSE be addressing this issue with the UTC so that a complete PSE DRAFT IRP will be available for review?
Kevin Jones	**1:17 PM**	James - I believe you filed a technical input (vice a comment)...
Doug Howell	**1:26 PM**	Raised hand. slide 19
Brian Grunkemeyer	**1:29 PM**	I strongly encourage PSE to invite land use planners throughout your service area to participate in the IRP Advisory Group.
Brian Grunkemeyer	**1:30 PM**	we have data on WA avoided tailpipe emissions from some EV's.
Don Marsh	**1:32 PM**	Are there any situations where a person would be excluded from the IRP Advisory Group? I ask because PSE once told me that I did not meet the qualifications for participating in the Technical Advisory Group. I hope that isn't happening any more.
Doug Howell	**1:33 PM**	Raised hand, follow up question on Slide 19?
Don Marsh	**1:34 PM**	Thanks for the answer, Irena. I am encouraged by PSE's increasing openness in that regard.
Elise Johnson	**1:42 PM**	A reminder to please mute your phone or computer mic to prevent feedback when speakers are presenting.
Michele Kvam	**1:43 PM**	Caller 04, please mute. Thank you.
Thad Curtz via Alexandra Streamer	**1:47 PM**	Reposting a question Thad Curtz posed to Organizers: Re Slide 22 **-** Is your view that any action which doesn't meet all of these criteria should be excluded from the plan, or is it that the suite of actions as a whole should meet these criteria?
James Adcock	**1:49 PM**	Slide 26: How do you want us to best send you our inputs requested on this slide?
Kyle Frankiewich	**1:54 PM**	Q on slide 29
James Adcock	**1:58 PM**	Comment: I would ask that for all PSE beneficially programs, such as weatherization, energy efficiency, etc. that PSE report on these programs divided into two groups -- the first section being ratepayers in the group "highly impacted communities and vulnerable populations" vs. the second group being ratepayers not in that group, and report actual financial spending normalized on a per ratepayer basis for the 1st group vs. the 2nd group -- such that we can see overall which PSE beneficially programs are equitably meeting the actual needs of each set of groups -- or not. For example I would be concerned that many PSE beneficially programs might be in practice inaccessible by the 1st group, either due to lack of funds, or because of the "split incentives" problem -- i.e. landlords vs. renters, or even just from a lack of understanding. If PSE beneficially programs for whatever reason are not reaching the 1st group, then that is an equity problem which needs to be actually fixed.

Don Marsh	**2:01 PM**	The Health Disparities Map is a very useful place to start. It shows that the census tract nearest PSE's Tacoma LNG facility is very highly impacted, vulnerable, and has a high percentage of residents from tribes. It would be useful to understand how PSE would change its approach under this policy. Would you find a better place for the plant? Would you seek higher participation from residents who have many difficult challenges they are facing? How are these policies implemented in practice?
Joni Bosh	**2:02 PM**	Will you be capturing downwind impacts in any of these initial metrics? Or just generation point impacts?
Michele Kvam	**2:03 PM**	Warren HALVERSON has some questions submitted in the IRP mailbox; he is on the phone
Fred Huette	**2:04 PM**	Has PSE reviewed the Avista assessment of Vulnerable Populations & Highly Impacted Communities? While this is an initial effort and can be enhanced and improved, this shows the promise of combining disparate data sources to provide important insights relevant to CETA and other planning contexts, and we recommend PSE and stakeholders take a look. Here's the most recent presentation (starting on slide 85): **https://www.myavista.com/-/media/myavista/content-documents/about-us/our-company/irp-documents/2021-irp-tac-2-presentations.pdf?la=en**
James Adcock	**2:05 PM**	Comment re slide 35 "Environmental Impacts." I am concerned that PSE has not been responsive to date to the issue of the environmental impact of new Transmission Lines, and how needless oppressive to the perceived environmental quality of the communities where a new transmission line is pushed though. For example PSE just cut down a huge number of beautiful trees along 148th in Bellevue, replacing those trees with gigantic creosote glue-lam poles -- some about 6 feet wide, and placed in the business property of a minority owner. PSE needs to honestly consider all the environmental impacts of their new transmission lines and make meaningful design choices to minimize the needless and excessive environmental damages and environmental ugliness of those transmission lines. Rather than just doing what is quickest and cheapest.
Bill Westre	**2:09 PM**	Raise Hand
Bill Westre	**2:09 PM**	James, that is a very good point. Transmission lines are often placed in impacted communities, because they are not seen as desirable in nicer parts of our community or business districts.
Warren Halverson via Michele Kvam	**2:09 PM**	From Warren Halverson: How does PSE map communities and/or customers to DOH maps? If the community can be defined down to the customer level, are you concerned at privacy issues?
Brian Grunkemeyer	**2:09 PM**	Raise hand
Charlie Black	**2:10 PM**	Kyle Frankiewich had a question on Slide 29 - has that been addressed?
Fred Huette	**2:12 PM**	raise hand for a follow-up
Joni Bosh	**2:14 PM**	Agree with Kyle's interpretation of slide 29

James Adcock	**2:16 PM**	Comment: The Slide 24 RCW quote makes it clear for the purposes of this section of environmental impact we are only considering the impacts on Washington State residents.
James Adcock	**2:18 PM**	Comment: +1 Brian -- avoided tailpipe emissions -- or the lack of avoided tailpipe emissions (where PSE's EV programs "fail") should be part of the consideration and evaluation.
James Adcock	**2:19 PM**	Comment: For example PSE support of electric busses might be a way to extend tailpipe reduction efforts to more communities.
Brian Grunkemeyer	**2:26 PM**	Great idea, Jim. Another idea would be looking at the Mileage Purchase Agreement as a financing mechanism to make EV's more affordable. This works out well for high-mileage drivers, including potentially transportation network company drivers. Adrian at Flux Auto is commercializing the MPA idea. **https://www.fluxauto.co/**
Brian Grunkemeyer	**2:29 PM**	(Sorry, it's Andrew, not Adrian)
James Adcock	**2:32 PM**	Slide 41: Does "Lowest reasonable cost" as related to "delivery system infrastructure" mean that PSE needs to implement transmission lines in a way that leads to needless and excess local environmental destruction?
Kevin Jones	**2:34 PM**	Slide 41: Given the new rules inclusion of electricity delivery systems in power planning, does PSE believe this applies to ALL transmission systems even if they were proposed prior to these new rules?
James Adcock	**2:38 PM**	Thank you I think you just did so.
Doug Howell	**2:38 PM**	Is PSE now assuming its full transmission capacity on the Colstrip Transmission System?
James Adcock	**2:39 PM**	Slide 44: How many times a year does my Bellevue neighborhood have to lose power before PSE considers that they are NOT delivering power "safely and reliably?"
Kevin Jones	**2:49 PM**	Follow-up to my earlier question: Does PSE believe that ALL transmission projects will be discussed in IRP and CEIP planning meetings even if those projects were proposed prior to these new rules?
Doug Howell	**2:49 PM**	Okay. Thank you
James Adcock	**2:51 PM**	Follow-up: We lose power all the time. Meanwhile PSE is arguing how many peakers do they need to avoid a system-wide outage every 20 years, or every 40 years, and "reach back in time" 100 years to find weather conditions which can no longer possibly exist -- and while ignoring that in practice our neighborhood loses it's power All The Time, because tree maintenance is not being done.
Charlie Black	**2:53 PM**	Regarding previously-planned transmission projects, can you clarify what 'included' means? Does that mean those projects will be evaluated, or will they be assumed to be built?
James Adcock	**3:00 PM**	Slide 48: Question: What does it take to actually get neighborhood tree maintenance so that we can actually experience the kind of safety and reliability which PSE claims it is designing it's power system to? We lose power all the time. Multiple times a year. Meanwhile PSE is arguing how many peakers do they need to avoid a system-wide outage every 20 years, or every 40 years, and is "reaching back in time" 100 years to find weather conditions which can no longer possibly exist -- and while ignoring that in practice our neighborhood loses it's power All The Time, because tree maintenance is not being done. What does it take so that we can actually in practice experience safe and reliable power delivery?

Charlie Black	**3:00 PM**	I do not see Energy Eastside listed on Slide 49. Does that imply the delivery system plan is assuming it will be built and therefore not evaluated in the delivery system plan?
Kevin Jones	**3:00 PM**	Slide 49: Which of these projects are associated with Energize Eastside?
Kyle Frankiewich	**3:01 PM**	Q on slide 43: Does PSE propose a threshold for what kinds or sizes of delivery system projects will be "included in the IRP"?
Warren Halverson via Michele Kvam	**3:04 PM**	Questions from the IRP mailbox from Warren: Two questions: 1. Is item 7 the Richards Road substation? 2. PSE did not submit a formal IRP this last year and, in fact, abruptly canceled a long awaited discussion of transmission and distribution activities. Now, with some details about CETA we can understand why😀 2. Please provide the current status and update where PSE is concerning Energize Eastside? Include, does PSE stand by their forecast of 2.4 per cent peak growth? If not what is the current peak demand forecast for the Eastside? Finally, Energize Eastside forecasts that took place 5-7 years ago showed we would basically be in deep trouble in 2019. That has not happened either winter or summer. We request you provide a 10 year Update to that forecast? Thank you, Warren Halverson
Kyle Frankiewich	**3:04 PM**	Q on slide 49: I see that these 11 projects are "in planning phase". Can PSE describe the various phases of the delivery system planning and implementation process, and detail how the handoff occurs from planning to implementation?
Joni Bosh	**3:07 PM**	Slide 49 - it looks like all of these projects would be pursued even if CETA didn't exist, correct?
Joni Bosh	**3:11 PM**	Thanks
Bill Westre	**3:16 PM**	When will DERMS and TOU be ready?
James Adcock	**3:18 PM**	Slide 51: In regards to "Enhanced Meter Data Visibility" will customers have the same access to their meter data that PSE has? If not why not -- why shouldn't we be allowed to have the same access to our own usage data as PSE has? Continued: For example is PSE has access to hourly meter data, can the customer have access to hourly meter data? If not why not?

Tom Eckman	**3:22 PM**	Slide 51 - Does PSE anticipate that it will ultimately have DER potential assessments by feeder (or substation) that is linked to its load forecast for that feeder/substation? Does PSE anticipate including DERs as resource options in its capacity expansion modeling? If so, does PSE anticipate initiating DER acquisition programs, similar to its EE programs, in addition to providing TOU or other rate design signals for DER development?
Lori Elworth	**3:23 PM**	Transmission line planning data should be updated prior to building if the data is not current. Customers are paying a huge price for old technology of Energize Eastside. There are better solutions today. Can this be addressed? Warren had some good questions that were not answered.
Joni Bosh	**3:23 PM**	Do you have an existing analysis/report on what PSE needs/is evaluating for Grid modernization? Slide 51, I think? My mistake, might be slide 52?
James Adcock	**3:30 PM**	Comment: Just to give one "Reality check point" I just checked what is available to me in terms of meter data, and I can still only access meter data on a daily-cumulative basis, not on an hourly basis. Having access to hourly-usage data would allow customers to begin to understand where their electrical and/or natural gas usage is going to -- allow them to actually target conservation and efficiency efforts.
Joni Bosh	**3:31 PM**	Thanks
James Adcock	**3:39 PM**	Raise hand
Cress Wakefield	**3:39 PM**	How are you currently working with commercial customers and large companies that are driving net positive energy goals on their sites?
Kyle Frankiewich	**3:41 PM**	Q on Jens's response: what litigation is pending regarding Energize Eastside, and why would that prevent conversation in the context of this public meeting?
Anne Newcomb	**3:43 PM**	Is PSE considering burying wires? If not why? With all of the trees and wind in this area I have always thought it makes sense.
Kyle Frankiewich	**3:45 PM**	follow-up: I can understand that there might be some hesitance to discuss issues under litigation right now. Could you provide more background for the legal dispute or a reference to it?
Bill Westre	**3:45 PM**	Thanks to all the presenters
Anne Newcomb	**3:46 PM**	Thanks!
Kyle Frankiewich	**3:47 PM**	Thank you for offering stakeholders additional time!

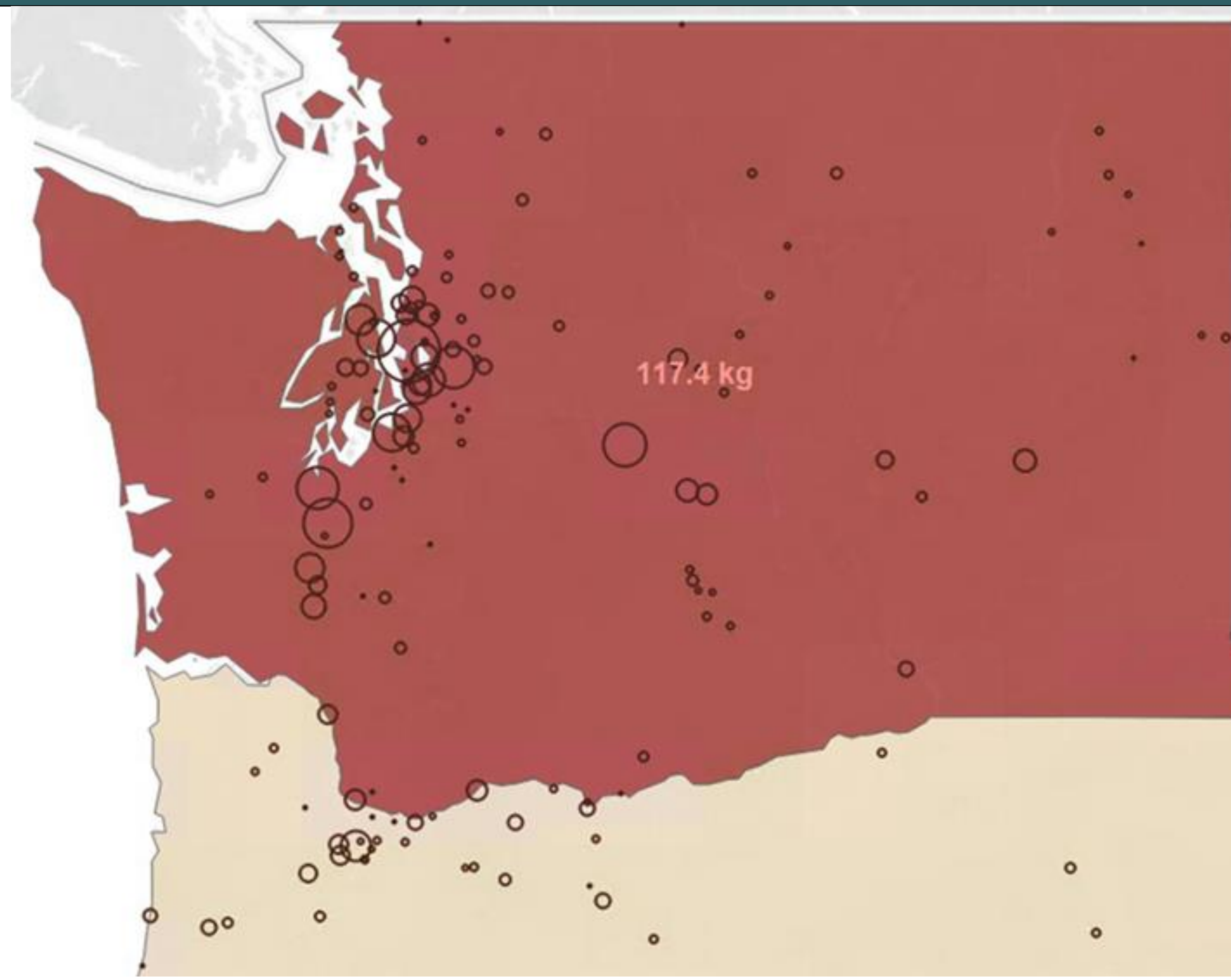
PSE IRP Feedback Report
Webinar 10: Clean Energy Action Plan (CEAP) and Clean Energy Implementation Plan, Economic, Health and Environmental Benefit Assessment of Current Conditions and Delivery System and Grid Modernization Needs
November 16, 2020

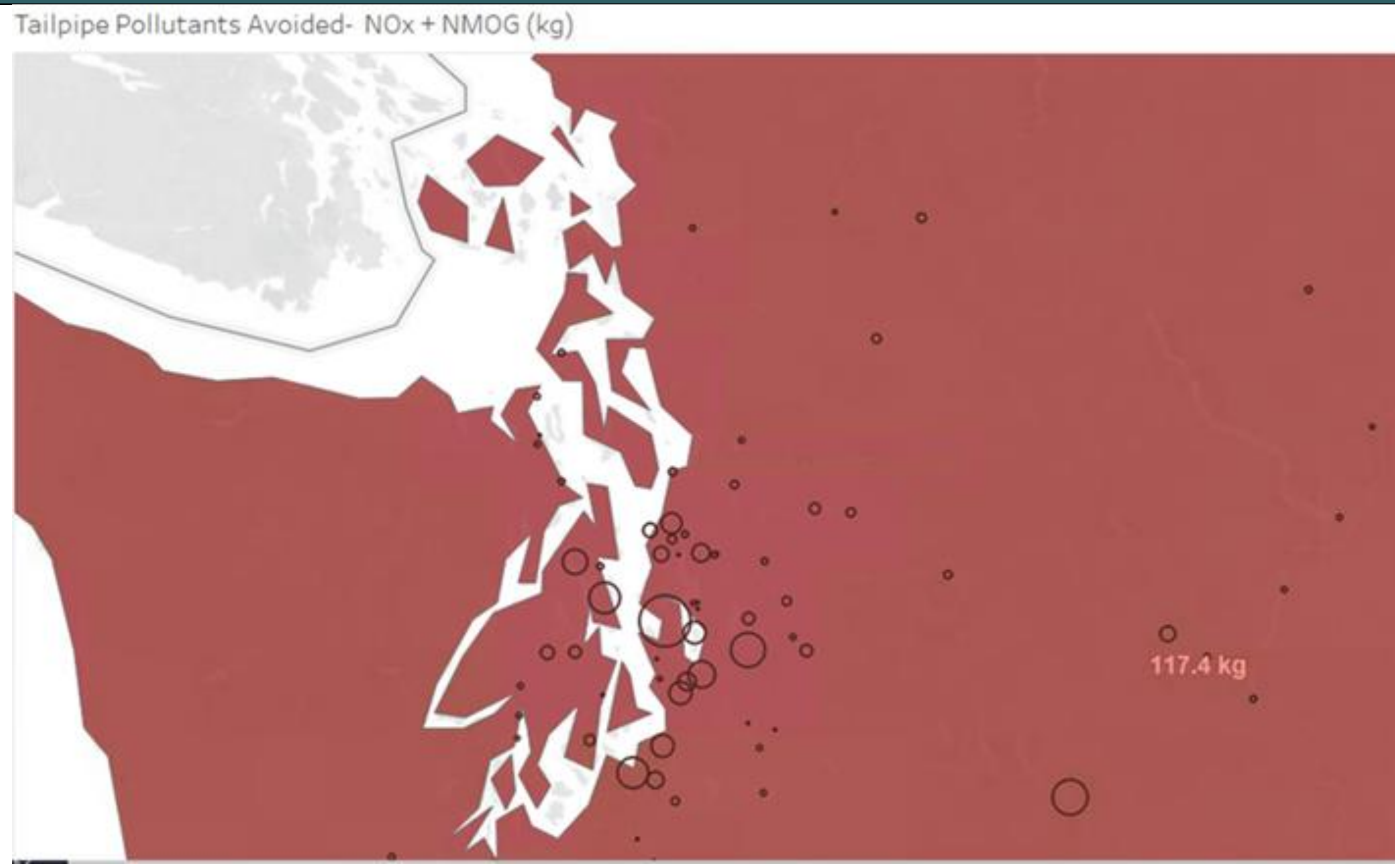
12/07/2020

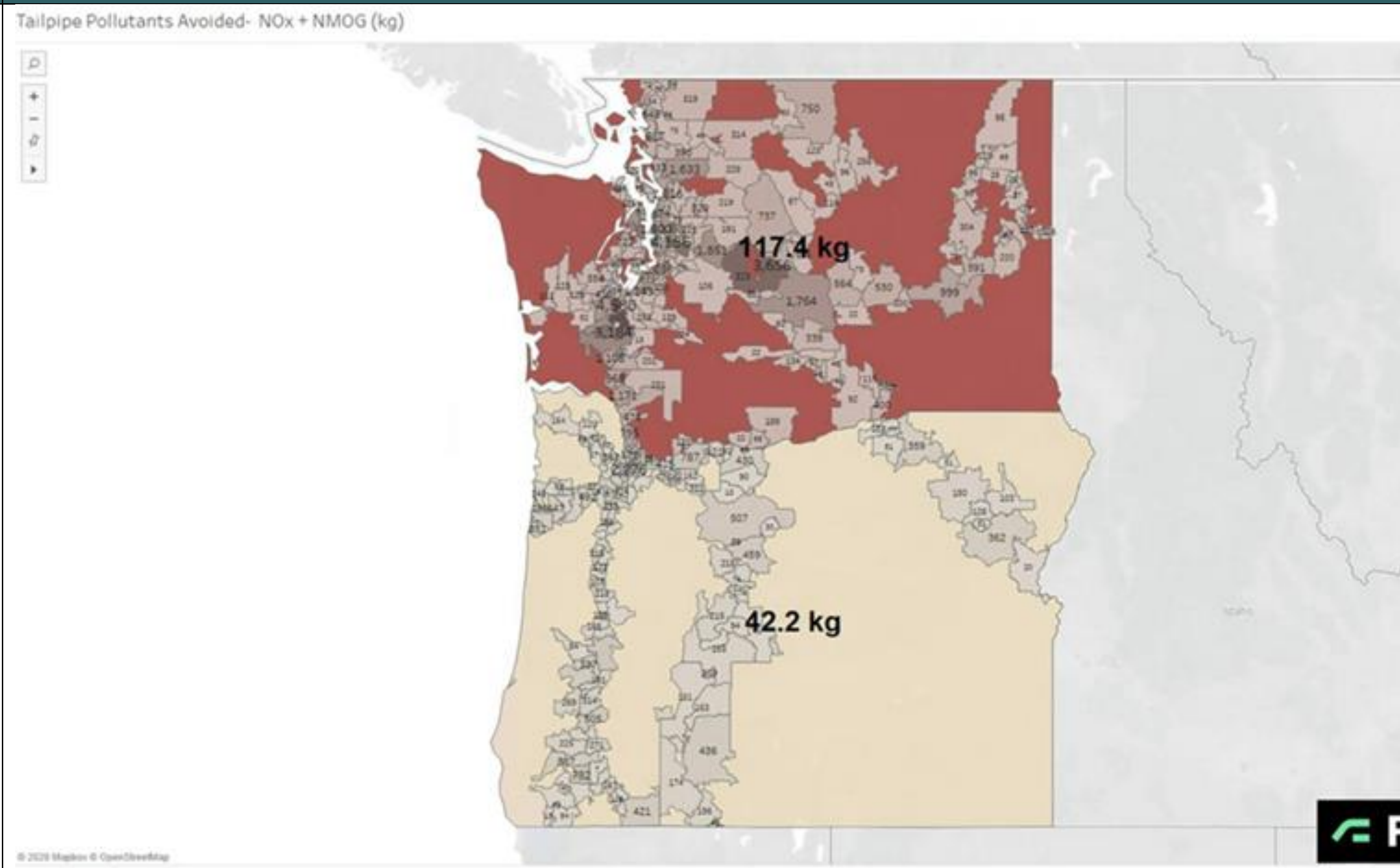
The following stakeholder input was gathered through the online Feedback Form, from November 9 through November 30, 2020. PSE's response to the feedback can be found in the far-right column. To understand how PSE incorporated this feedback into the 2021 IRP, read the Consultation Update, which will be released on December 14, 2020.

Feedback Form Date	Stakeholder	Comment	PSE Response
11/13/2020	Don Marsh, CENSE	Dear PSE IRP Team, Thank you for the slides for the November 20 IRP webinar posted at https://oohpseirp.blob.core.windows.net/media/Default/2021/meetings/Nov_16_Webinar/Webinar%2010%20-%20Presentation.pdf. We would like to comment on the section titled "Highly Impacted Communities and Vulnerable Populations Assessment" (beginning at slide 27). In this section, PSE describes how the company will *measure* population disparities, but it is not clear what the company will *do differently* after it has collected this information. An example would be helpful for stakeholders to understand how PSE has fulfilled this responsibility in the past, how effective these efforts have been, and what PSE will change in the future to meet CETA requirements. For example, district 53053940005 in Tacoma is located approximately 1.25 miles from PSE's new Tacoma LNG facility. By our calculations, this district scores 54 points out of a maximum of 75 using the "Final composite score" formula on slide 33. By any measure, this is a "highly impacted community." Accordingly, it would be helpful for stakeholders to know: • What extra efforts did PSE make to engage a community that endures challenging socioeconomic factors such as Limited English (rank 8), People of Color (rank 9), and unemployment (rank 8)? • This community suffers the second-highest rank in overall Environmental Exposures and Environmental Effects categories. What steps did PSE take to assure the community that the LNG plant would not further impact the health and well-being of its residents? • What percentage of this community was fully engaged in the process? What percentage submitted written and oral and written comments in public meetings regarding the facility? Was this response proportional to the proximity of the community to the project? • In the future, what steps could PSE take to better engage a community that is disadvantaged by language, culture, and employment conditions? PSE's answers to these questions have relevance to the question posed on page 37: "Who do we need to involve to improve the analysis?" In addition to our concerns about representation and treatment of vulnerable populations, we would like to comment on slide 45 regarding the Delivery System Planning process. The first box lists "Assumptions, performance targets and modeling input" as a primary step to establishing grid needs. However, these assumptions and performance targets are not available to the public for comment and review. In various forums, PSE has claimed this information is restricted by federal laws that protect the energy grid from malicious attacks by terrorists. We support reasonable restrictions on information to inhibit terrorist attacks. However, PSE has also prevented individuals and experts with appropriate security clearance from seeing these assumptions and performance targets. In the case of Energize Eastside, PSE has not updated its forecasts or analysis that justify the project since 2015. However, PSE acknowledges that demand forecasts and energy technologies have changed significantly during the last five years. State legislation has also changed in important ways. Questions about Energize Eastside are relevant to Monday's webinar because PSE lists a "Bellevue Area New Substation" on slide 50 without explanation of the capacity need it is addressing. This substation is an integral part of the Energize Eastside	Thank you for your comments on the Economic, Health and Environmental Benefits Assessment of Current Conditions and feedback on equity. As discussed during the webinar, PSE is at the beginning of the evaluation and the purpose of the webinar was to solicit input from stakeholders to help inform the assessment. The assessment will inform the outcome of the final IRP. Concerning PSE's efforts to broaden public engagement, efforts were made in early 2020 to broaden the 2021 IRP participation and an email list of more than 1,500 people was developed with input from regulators, stakeholders, and community outreach specialists. Personal phone calls were made to invite targeted individuals representing various communities and populations to participate. There is more work to be done concerning outreach and inclusion. There have been challenges with all meetings of the 2021 IRP process conducted remotely because of COVID-19 restrictions and PSE welcomes input concerning outreach and solutions for inclusion. The need for the Energize Eastside project has been firmly established going back to 2013; information regarding the need for the project can be found on their website at www.energizeeastside.com. Any further questions should be directed to the energize eastside team via their dedicated e-mail, energizeeastside@pse.com.

Feedback Form Date	Stakeholder	Comment	PSE Response
		project. PSE claims that it has verified the need for this project with supplemental studies in 2016, 2017, 2018, and 2019. However, the company has not shared the results of these studies with the public or consultants hired to represent the public. We would like to verify that PSE has appropriately updated its assumptions and forecasts that underlie these studies. Such disclosures are important to set the stage for increased transparency and accountability – key elements for a just and equitable Clean Energy Transformation. Sincerely, Don Marsh, President CENSE.org	
11/16/2020	James Adcock	I express concerns about the big elements which will not be ready in time for the Draft IRP -- including that which has been most controversial over the last 12 years, namely the stochastic modeling -- which I believe will keep participants from commenting in an informed manner on that Draft. I recommend that PSE and UTC figure out some way to get substantially complete modeling efforts, including the stochastic modeling, in the "Draft" IRP time frame, so that the IRP participates can meaningfully comment on elements of that draft which they believe are in error. Otherwise it becomes an invitatation for PSE to slip-stream the more controversial aspects into just the final IRP document, such that no timely feedback can be given, and PSE, after continually blocking meaningful conversations with participants during the IRP meetings, now creates a fait accompli -- where participants are effectively frozen out of the entire IRP process up through the final IRP documentation being published.	PSE acknowledges your concerns and is working to include all the analysis conducted to date in the draft IRP, due January 4, 2021. PSE looks forward to stakeholder feedback on the draft. PSE will host two more public participation meetings in 2021 before the final IRP to review the remaining analysis and obtain stakeholder feedback.
11/16/2020	Cress Wakefield, ARUP	Recommend including timelines as part of the IRP on delivery system planning for DERMS and TOU, as the carbon initiatives of large commercial companies and cities seem to be outpacing the readiness of the utilities. Even if the incentives/pricing were unclear, it would help with planning.	Thank you for your suggestions. The timeline for TOU pilot activity will be included in the IRP. The timeline for DERMS implementation is in development, but will be discussed in the IRP.
11/16/2020	Brian Grunkemeyer Founder & CEO FlexCharging, Inc.	I wanted to follow up with Tyler Tobin and Ben Farrow about tailpipe emissions from gasoline cars. We can use that to justify accelerating EV adoption. We have a deep but not broad data set. I suggest we could work together to collect more data to better make a compelling case for additional spending on increasing EV adoption. In terms of indicators of equity, I suggest you include air pollution. Specifically, EV investments that speed up adoption will avoid tailpipe emissions from gasoline vehicles, *in specific communities*. We all know air pollution impacts human health, through asthma attacks and shortened lifespans. But programs increasing EV adoption can help avoid air pollution, and therefore avoid these health impacts and costs. For the vehicles signed up with FlexCharging, my team has analyzed the avoided NOx + NMOG tailpipe pollution, grouped by city. There are also avoided pollution from particulate matter, formaldehyde, and carbon monoxide, all informed by EPA estimates. Note most of the drivers live in the Seattle & Eastside area (and some in Portland), but the avoided tailpipe emissions impact is statewide. This data of course requires tracking cars & where they drive, instead of focusing on smart plugs.	Thank you for input and suggestions. This is interesting work, which may hold value during the development of PSE's Clean Energy Action Plan (CEAP) and Clean Energy Implementation Plan (CEIP). PSE will follow up outside of this Feedback Report to learn more about FlexCharging, Inc.'s data set and its applicability to PSE's models.

Feedback Form Date	Stakeholder	Comment	PSE Response
		 Zooming in, you can see more details about affected communities:	

Feedback Form Date	Stakeholder	Comment	PSE Response
		 We get this data by polling vehicle status regularly when driving. We have high resolution GPS data, which we can then map to zip codes, or with a little work, down to the census tract. Here's our data broken down by zip code. State level numbers are in kg, and each zip code is in g.	

Feedback Form Date	Stakeholder	Comment	PSE Response
		 Our data shows a statewide benefit to many communities, to augment the equity benefits from accelerating EV adoption. FlexCharging can provide a data gathering piece for your measurement & verification needs, to demonstrate this benefit. There are two very clear answers for policy makers: 1) WA air pollution exposure is highest in the Puget Sound region, heavily overlapping with your service territory. 2) Benefits from EV's in Bellevue extend to air quality improvements statewide, in addition to just the owner's territory. We additionally support managed charging to optimize around dynamic prices from a utility, and we're working on optimizing around minimizing marginal CO_2 emissions, using an emissions forecast from WattTime. The money aspect impacts all ratepayers by affecting your costs, while the carbon emissions impact is global, though quantifying it can help the US as we establish national goals under the Paris Climate Accord. At some point, national goals need to translate into per-state and per-utility level commitments. We can support your efforts with our data set, and perhaps we could collaborate on expanding this data set.	
11/24/2020	Don Marsh, CENSE	Dear PSE IRP Team, I seek further details regarding a statement by Jens Nedrud in IRP Webinar #9 at timestamp 02:10:35 (see the recording at https://transcripts.gotomeeting.com/#/s/74f800380e1968d7d6749493e6c8287fbf835cb8af1a8321f59b6590ed2a5e0c). Mr. Nedrud said: "*I will say that we have experienced significant summer peaking events that have caused our operators a little bit of challenges in operating the grid that Energize Eastside would have addressed. So again, you can find more information on the project website.*"	The need for the Energize Eastside project has been firmly established going back to 2013; information regarding the need for the project can be found on their website at www.energizeeastside.com. Any further questions should be directed to the energize eastside team via their dedicated e-mail, energizeeastside@pse.com.

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<tr><th>Feedback Form Date</th><th>Stakeholder</th><th>Comment</th><th>PSE Response</th></tr>
<tr><td></td><td></td><td>Checking the website (https://energizeeastside.com), I find no details about summer peaking events that strained the transformers and transmission lines that PSE proposes to upgrade.

Answers to the following questions would help us understand the situation Mr. Nedrud alluded to.

1. On what dates and hours did the challenges occur that Mr. Nedrud mentioned?
2. What was the peak load (in MW) that was being consumed by Eastside customers at the time?
3. What percentage of their peak capacity was experienced by the four Eastside transformers and two transmission lines that would be relieved by Energize Eastside upgrades?
4. How long did the stress conditions last?
5. What actions did operators take to alleviate the problem?
6. Approximately how many customers would have lost power if the operators had not acted?
7. How many times have similar conditions occurred during the past decade?

Thank you for providing these clarifying details to help the public understand the need for Energize Eastside.</td><td></td></tr>
<tr><td>11/30/2020</td><td>Don Marsh, CENSE</td><td>Dear PSE IRP Team,

The attached letter contains questions regarding Jens Nedrud's presentation in IRP Webinar #9 regarding disclosure of information on major projects (including Energize Eastside, which has never been discussed in an IRP Advisory Group meeting).

I hope PSE will answer these questions to avoid possible denial of rate increases for projects that have not been transparently presented to the public or land use examiners. That unfortunate outcome would harm not only PSE and its investors, but also ratepayers who need a financially healthy utility to make critical investments expected by CETA.

Sincerely,
Don Marsh</td><td>As discussed at the IRP meeting, the portion of the IRP pertaining to the "Delivery System and Grid Modernization Needs" specifically discussed the planning process to evaluate needs on PSE's delivery system. PSE also discussed the future planned growth/project areas currently in the planning phase. These include all major projects that require substantial transmission and/or distribution infrastructure. Each of the projects has an identified need and alternatives are being analyzed.

As highlighted at the meeting, projects in the implementation phase, which are those in permitting, construction or energization, will be discussed at a future IRP webinar, currently scheduled for February. These projects alternatives have already been evaluated and their recommended solution selected.

Specific to the question posed related to Energize Eastside discussion in prior IRP processes, the need for that project has been discussed in multiple prior IRP processes and included in those plans. Each of those processes has allowed for and included public engagement including stakeholder presentations as well as incorporated public comments.

The Energize Eastside project is in the implementation phase and there have been no significant changes in either the need for the project or the solution evaluation which warrant a change to the recommended solution. Therefore, the Energize Eastside project will not be discussed at any upcoming 2021 IRP webinars. For the specific questions related to the project status and need for the Energize Eastside project, please refer those questions to the project e-mail at energizeeastside@pse.com.</td></tr>
<tr><td>11/30/2020</td><td>Scott Thomas, Town of La Conner</td><td>Affordability challenges may lead to shutoffs or disconnections due to non-payment. PSE should report out which and how many households are shut off on an annual basis, and make the data publicly available. The data should be analyzed to ascertain the prevalence of disconnection notices and service disconnections served on low-income households, African-American and Latino households, households with children, renters, and people living in older and poorly insulated homes. Further, there is a need to explore the coping strategies that families resort to to keep their homes warm and lit, such as forgoing food and medicine and keeping homes at an unhealthy temperature.</td><td>PSE recognizes this is a difficult time for many customers and has voluntarily suspended disconnections due to non-payment since early March of this year. Such disconnections will not resume before May 1, 2021, consistent with recent direction from the Utilities and Transportation Commission (UTC) related to COVID-19 relief. Additionally, PSE will be providing additional COVID-19 related energy assistance funds to low-income households needing help paying their energy bills during this time.

PSE is already reporting data by zip code regarding prior disconnections, past due balances, and related data points to the UTC in Docket UE-200281.</td></tr>
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Feedback Form Date	Stakeholder	Comment	PSE Response
11/30/2020	David Perk, 350 Seattle	Irena Netik, Director, Resource Planning & Analytics Ben Farrow, Director, Clean Energy Strategy, PSE Tyler Tobin, Resource Planning Analyst, PSE Thank you for your presentation on November 16 covering Highly Impacted Communities & Vulnerable Populations Assessment. 350 Seattle is glad to see that lawmakers have compelled Puget Sound Energy to take equity into account. Unfortunately, we're not surprised that it would require legislation, given PSE's history. Environmental racism has been a hallmark of the Tacoma LNG project. With insufficient consultation with the Puyallup Tribe (1), failure to acknowledge health and safety risks to the highly vulnerable populations around the facility (2), and construction before all permits were secured, PSE's relentless pursuit of the project has been a tremendous stress to vulnerable communities in Tacoma. Given this negative track record, PSE is going to have to dramatically improve its outreach and consultation with affected communities, and especially tribes, when undertaking future facilities and infrastructure projects. The choice of fracked gas as a replacement maritime fuel is itself deeply problematic. Fracked gas has profound social and health impacts at the site of extraction, and its global climate impacts can no longer be denied. Man camps used during the construction and extraction of fossil fuels have been linked to spikes in the epidemic of missing and murdered indigenous women and hardships to indigenous communities (3). Fracking produces large quantities of toxic water, poisoned wells and water tables, earthquakes, habitat and biodiversity loss (4). Young people locally and across the world recognize they face a bleak and uncertain future as a result of the climate crisis caused by fossil fuel use (5). By seeking to preserve and expand its gas business, PSE denies those impacts and works to ensure they continue by cynically targeting children who have already lost the prospect of a stable climate in their future (6). Our advice: reach out to local members of the Sunrise Movement for inclusion in the equity advisory group and end your relationship with the Partnership for Energy Progress. In our view, your equity advisors can't start soon enough. During the Covid-19 pandemic PSE has put profits over people, seeking to have ratepayers cover all additional costs incurred during the pandemic. To do this while your top executives, in the top 1% of state salaries, take no reductions in pay, is simply callous (7). Our advice: increase assistance to economically challenged ratepayers and consult with members of the utility justice movement, if they're willing to meet with you, like Puget Sound Sage. The recommended health disparities map is a good start (8) and we encourage you to continue your outreach for additional datasets. We urge you to implement a scope of action beyond the direct effects of PSE facility, infrastructure and fleet emissions. Equity efforts should include addressing air quality, both indoor (gas appliances) and out (tailpipe emissions). PSE is uniquely positioned to contribute to regional air quality solutions by supporting electric trucking in the Puget Sound freight corridor, and faster, wider electric vehicle adoption, including in low income areas. By contributing more air monitoring to regional data sets, PSE could help better identify point-sources and help verify future improvements. PSE should help build resilient communities by dramatically increasing your weatherization and community solar programs, and start implementing local storage and micro-grids (9). Finally, PSE needs to recognize the hard truth that your fossil gas business has no place in a decarbonized future (10). We urge you to start planning a path to get there. Sincerely, David Perk	Thank you for your input and suggestions. PSE appreciates the recommendations to contact Partnership for Energy Progress and Puget Sound Sage as an Equity Advisory Group is established. Public health will be key component of the Economic, Health and Environmental Benefits Assessment, as such, air quality will certainly be included in the assessment.

Feedback Form Date	Stakeholder	Comment	PSE Response
		350 Seattle 5031 University Way NE Seattle, WA 98105 References (1) Washington Tribes stand with the Puyallup Tribe, http://news.puyalluptribe-nsn.gov/washington-tribes-stand-with-the-puyallup-tribe/ (2) Tacoma Human Rights Commission, http://news.puyalluptribe-nsn.gov/wp-content/uploads/2019/04/THRC-LNG-rec-ltr-for-4.18.19-mtg-1.pdf (3) Man Camps Fact Sheet, http://www.honorearth.org/man_camps_fact_sheet (4) Environmental Health Concerns From Unconventional Natural Gas Development, https://oxfordre.com/publichealth/view/10.1093/acrefore/9780190632366.001.0001/acrefore-9780190632366-e-44 (5) Global Climate Strike, https://globalclimatestrike.net/ (6) Puget Sound Energy Wants Your Kids to Love Natural Gas, https://www.thestranger.com/slog/2020/06/26/43974948/puget-sound-energy-wants-your-kids-to-love-natural-gas (7) AG Ferguson calls on UTC to protect Washingtonians from utility shut-offs amid COVID-19 pandemic, https://www.atg.wa.gov/news/news-releases/ag-ferguson-calls-utc-protect-washingtonians-utility-shut-offs-amid-covid-19 (8) Washington Tracking Network (WTN), https://fortress.wa.gov/doh/wtn/WTNIBL (9) Building Back Better: Investing in a Resilient Recovery for Washington State, https://climate-xchange.org/2020/06/30/building-back-better-investing-in-a-resilient-recovery-for-washington-state/ (10) Draft 2021 State Energy Strategy, https://www.commerce.wa.gov/wp-content/uploads/2020/11/WA-2021-State-Energy-Strategy-FIRST-DRAFT-2.pdf	
11/30/2020	Nathan Sandvig	Please see attached. Thank you.	Thank you for all your suggestions and for the Navigant white paper reference. PSE has done a lot of work for the externality costs and decommissioning costs associated with combustion turbines and have not seen a lot of information around the costs associated for battery energy storage systems. PSE will continue to monitor the costs and externalities associated with battery storage.
11/30/2020	Norman Hansen	FYI. PSE feedback form submitted concerning an IRP discussion on Energize Eastside Transmission line proposed North Segment. Submitted comment and request: " Energize Eastside Transmission line North Segment has not yet been permitted. Consequently, it is not yet in the implementation phase and should be discussed at the next IRP meeting. Please advise your concurrence to discuss to meet the intent of the Washington Administrative Code."	As highlighted at the meeting, projects in the implementation phase, which are those in permitting, construction or energization, will be discussed at a future IRP advisory group meeting, currently scheduled for February.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Questions and recommendations from presentation:	Thank you for your questions and recommendations. PSE inserted each item below along with PSE’s responses.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 16: The slide include equity considerations as part of the CEAP, but not the IRP. RCW 19.280.030(1)(j) requires that the IRP implement RCW 19.405.030 through 19.405.050, which includes the customer benefit provisions in 19.405.040(8).	Thank you for your feedback and code references concerning “the new planning cycle.”
11/30/2020	Kyle Frankiewich, Washington	Slide 17: As in slide 16, staff notes that the statute has equity requirements for the IRP specifically. We hope PSE will reconcile its economically optimized portfolio and all equity requirements within its IRP broadly, and not just within the CEAP.	Thank you for your feedback. The portfolio optimization model is a computer mathematical model that needs defined inputs and equations. Given that the assessment is new for the IRP, PSE will be looking at it outside the computer model and adjusting the portfolio.

Feedback Form Date	Stakeholder	Comment	PSE Response
	Utilities and Transportation Commission		
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 19: During the meeting, PSE verbally acknowledged that highly impacted communities and vulnerable populations are relevant customer groups. Staff agrees that these groups should be specific, intentional customer groups that are specifically engaged.	Thank you for your feedback and support that highly impacted communities and vulnerable populations are relevant customer groups who should be engaged. Efforts were made in early 2020 to broaden the 2021 IRP participation and an email list of more than 1,500 people was developed with input from regulators, stakeholders, and community outreach specialists. Personal phone calls were made to invite targeted individuals representing highly impacted communities and vulnerable populations to participate. PSE agrees with you that there is more work to be done concerning outreach and inclusion. There have been challenges with all meetings of the 2021 IRP process conducted remotely because of COVID-19 restrictions and PSE welcomes input concerning outreach and solutions for inclusion.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 20: During the meeting, PSE verbally acknowledged that customer input is relevant for indicator development. Staff agrees that customer input is necessary for indicator development. Proposed CR-102 rules at WAC 480-100-655(2)(a) require customer input to develop indicators. Additionally, the Equity Advisory Group should be involved in the Company's CEIP in addition to the Low Income Advisory Group and Conservation Resources Advisory Group.	Thank you for your feedback. PSE is actively working toward establishing an Equity Advisory Group to help develop indicators and the broader CEIP. PSE also looks forward to continued engagement with stakeholders and customers including the IRP public participation process, Equity Advisory Group, Low Income Advisory group and Conservation Resources Advisory group.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 22: The slide uses the term "equitably distributed" in the triangle graphic. Staff recommends using the term "customer benefit" to refer to the full set of requirements in 19.405.040(8) and included in proposed CR-102 rules at WAC 480-100-610(4)(c), including the elements required by -4(c)(ii) related to public health, environment, and reductions and costs and risks as well as those required by -4(c)(iii) related to energy security and resilience. The term "equitably distributed" may unintentionally be seen to only refer to the requirements in -4(c)(i) related to the equitable distribution of benefits and reduction of burdens to vulnerable populations and highly impacted communities.	Thank you for your feedback concerning the word selection on slide 22: Meeting CETA goals. In future presentations, PSE will better clarify that all aspects of WAC 480-100-610(4) are clearly indicated. It was not PSE's intention to limit focus to -4(c)(i).
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 25: This is a good slide! It is busy, but that is appropriate given the myriad considerations and concepts being represented.	Thank you for your feedback concerning slide 25: Incorporating the Assessment into the IRP.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 26: Staff understands these questions to be the start to a productive conversation. Staff's initial responses are in the next section.	Thank you for your feedback.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 28: Staff understands this slide to help stakeholders parse energy and non-energy benefits might be assessed through this analysis.	The intention of slide 28: Assessment Objectives is to introduce stakeholders to the concept of the Economic, Health and Environmental Benefits Assessment. Then to provide some context as to the different data types necessary to complete such an assessment. Finally, how those data types do not necessarily align with existing IRP model framework and illustrate the effort needed to incorporate this new modeling framework into existing IRP models.
11/30/2020	Kyle Frankiewich, Washington	Slide 28. During the meeting, PSE verbally references the assessment as a quantitative assessment. Staff recommends that the Company consider qualitative input as well as qualitative information can inform the Company's judgement and discretionary decisions when developing its preferred portfolio.	Thank you for your suggestion to consider qualitative information in addition to quantitative information in the Economic, Health and Environmental Benefits Assessment. PSE acknowledges WAC 480-100-605 defines an indicator as an either qualitative or

Feedback Form Date	Stakeholder	Comment	PSE Response
	Utilities and Transportation Commission		quantitative attribute. PSE looks forward to developing a robust set of indicators with stakeholders, which will inform the assessment.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 29: This process map seems unnecessarily linear. We envision steps 1 and 2 to happen in parallel. As mentioned during the meeting, Staff notes that the identification of highly impacted communities and vulnerable populations should not be depicted as a precursor to developing the current conditions assessment pursuant to RCW 19.280.030(1)(k) as these are distinct work products. ○ The designation of highly impacted communities is outlined in statute in RCW 19.405.020(23). Specifically, highly impacted communities must be based on the Department of Health's Cumulative Impact assessment, which will identify impacts based on climate change and fossil fuels, and census tracts that are at least partially in Indian Country. The process for designating vulnerable populations is described in proposed CR-102 rules at WAC 480-100-640(4)(b). ○ The assessment described in RCW 19.280.030(1)(k) should capture energy and nonenergy benefits and burdens from utility programs and infrastructure, as well as general public health, environment, costs, risks, and energy security for all customers. ○ After completion, these two work products should help to determine disparities in current condition for highly impacted communities and vulnerable populations compared to all other utility customers. The degree of disparity will guide the proportion of benefits, including the reduction of burdens, should be directed to highly impacted communities and vulnerable populations during the transition to clean energy to ensure an equitable distribution.	Thank you for sharing the WUTC's perspective on the expected workflow and work products of the Economic, Health and Environmental Benefits Assessment. Upon reflection, PSE would agree that most of the work and results of steps 1 and 2 could be completed in parallel and will endeavor to do so during the assessment. PSE also agrees with the Staff's interpretation of determining the disparities based on the two work products.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 33: This is useful, and it is clear that the company's initial approach to the equity assessment has benefited from the IRP team's thoughtfulness. However, we worry that a purely quantitative approach will not capture the benefits of a qualitative review as well.	Thank you for your feedback concerning PSE's first approach concerning identifying the characteristics of the Economic, Health and Environmental Benefits Assessment. PSE acknowledges WAC 480-100-605 defines an "indicator" as an either qualitative or quantitative attribute. PSE looks forward to developing a robust set of indicators with stakeholders, which will inform to the assessment.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 33: The process for identifying vulnerable pops is codified in draft rule. How does PSE's approach align with that guidance?	WAC 480-100-605 defines a vulnerable population as "communities that experience a disproportionate cumulative risk from environmental burdens due to: Adverse socioeconomic factors, including unemployment, high housing and transportation costs relative to income, access to food and health care, and linguistic isolation; and sensitivity factors, such as low birth weight and higher rates of hospitalization." For the 2021 IRP, PSE intends to rely on the DOH Environmental Health Disparities Map, which includes many of these factors (as indicated by the stars on the slide), among others, in its composite score, to help identify vulnerable populations. However, as an Equity Advisory Group is established and further opportunities for public participation are made available, PSE intends to evolve its methodology and criteria for identifying vulnerable populations.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 35: Staff notes that the economic, health, and environment graphics on this slide should be considered as a subset of the disparities PSE considered. We hope this slide is illustrative rather than comprehensive. The assessment described in RCW 19.280.030(1)(k) must include data on energy and nonenergy benefits, costs and risks, as well as energy security. Therefore, the measurement of disparities should also reflect these categories. Related to our comments regarding slide 20, Staff recommends that the Company consider the disparities assessment an overlay to the Economic, health, and environmental burdens and benefits where the assessment itself focuses on understanding current conditions for all PSE customers.	Slide 35 was intended to illustrate, in broad strokes, the aims and methods of the assessment. PSE's Economic, Health and Environmental Benefits Assessment will fulfill all requirements of RCW 19.280.030(1)(k).

Feedback Form Date	Stakeholder	Comment	PSE Response
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 36: The company's methodology sketched out here implies that draft rules under draft WAC 480-100-610(4)(c) describes three separate customer benefit requirements. This is not staff's current understanding of the draft rule, though ideally this will get clarified in rule or in the adoption order	PSE believes this comment may be in reference to slide 35, in which case, PSE would reiterate the response above, "Slide 35 was intended to illustrate, in broad strokes, the aims and methods of the assessment. PSE's Economic, Health and Environmental Benefits Assessment will fulfill all requirements of RCW 19.280.030(1)(k)."
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 36: Staff notes that qualitative measures are also called out in statute, and may inform the CEIP. Also, the definition of vulnerable populations (VPs) is different from HICs. The attributes that make a PSE customer a member of a VP might not inherently or per-se be geographically clustered, and may not map obviously onto a geospatial analysis.	Thank you for pointing out the distinction between the disparate definitions of vulnerable populations and highly impacted communities. PSE has lumped these terms together for the purposes of this presentation, as we are still waiting on the results of the DOH cumulative impact study to identify highly impacted communities. PSE intends to incorporate qualitative metrics as the CEIP process progresses. An initial assessment, relying on quantitative metrics, will be conducted as a stepping stone to a more robust assessment following input from an Equity Advisory Group and further public participation. PSE acknowledges that a geospatial analysis may not account for each individual customer within a given geographic region. PSE is working to identify methods to limit the influence of these shortfalls and will incorporate new methods as they are established.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 36: To clarify, in staff's view, PSE does not have to show progress in the assessment metrics; the company should demonstrate progress in the indicators. The indicators don't necessarily map 1:1 to assessment metrics. Tailpipe emissions may be a good example in this regard, in that EV adoption may ameliorate air quality but air quality is not only correlated to ICE vehicles.	Thank you for providing improved clarity the relationship between assessment metrics and indicators.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 43: The public meeting chat discussion at ~2:50pm focused on applicability of CETA planning requirements to Tx projects currently being pursued by PSE. Participant Black asked about which projects are being assumed as built within the IRP. PSE's Nedrud clarified that projects such as Energize Eastside are in the implementation phase. What are the phases that were referenced? What types of investments follow this phased development approach? What phases will PSE include as a part of decisions made and supported within the IRP, and in what phases are projects included as finished projects? Has PSE typically included capital-intensive projects in the company's IRPs at a certain phase (perhaps a planning phase?), but not at others (like an implementation phase)?	All projects have a lifecycle including planning and implementation (consisting of permitting, construction and energization). Large projects specifically follow this development approach. Project needs are identified and alternatives are analyzed during the planning phase. Feedback and input on those will be sought as part of this IRP process and also through PSE's attachment K stakeholder process in accordance with PSE's FERC requirements. The solution is then selected based on that alternative analysis as well as feedback. Once a solution is identified and the project moves to the implementation phase, stakeholder engagement transitions to the local outreach and the jurisdiction governing permitting requirements. After identifying the recommended solution, PSE does not use the IRP process to continue to evaluate a solution unless there are significant changes that warrant revisiting. Specific to Energize Eastside, this project is in the implementation phase and there have been no significant changes in either the need for the project or the solution evaluation which warrant a change to the recommend solution. The typical types of investments for major projects include solutions to address needs identified to meet NERC compliance requirements on the transmission system, new distribution substations to meet local capacity needs or other projects which would reconfigure the topology or modify transmission system ratings.

Feedback Form Date	Stakeholder	Comment	PSE Response
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Slide 51: Does PSE anticipate that it will ultimately have DER potential assessments by feeder (or substation) that are linked to the company's load forecast for that feeder or substation? Does PSE anticipate including DERs as resource options in its capacity expansion modeling? If so, does PSE anticipate initiating DER acquisition programs, similar to its EE programs, in addition to providing TOU or other rate design signals for DER development? Participant Eckman asked questions along these lines verbally, and staff includes them here with the hope of a written response.	At this time, PSE is not planning to produce DER potential assessments akin to the conservation potential assessment at the feeder or substation level. However, hosting capacity analysis will allow PSE to understand where DERs can be sited without significant additional investment in the electric system. As verbally stated, PSE is including DERs as resource options in the capacity expansion model. Regarding DER acquisition programs, PSE anticipates defining the acquisition process as appropriate in the Clean Energy Implementation Plan.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	Feedback and recommendations separate from slides: Note: Many recommendations for this meeting are included in the slide-specific comments above.	Thank you for your feedback and recommendations separate from the slides. PSE inserted each item below along with PSE's responses.
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	**Responses to PSE's questions re: equity assessment** a. How do we measure disparities affecting highly impacted communities and vulnerable populations? i. Surveys and advisory groups are also a good way to understand these disparities. ii. The metrics themselves are explored more in the second question, but some other views into these disparities could come from PSE's customer data. For example, historical usage data could help the company identify disparities in weatherization within a neighborhood's housing stock. If an address's load is substantially more temperature-dependent, that home would likely be a good candidate for efficiency measures. b. Are there quantifiable public health and environmental benefits and reductions of costs and risks? i. The metrics on slide 33 are a great start. 1. Transportation issues are represented fairly by "transportation expense." This topic could also include average commute time, as well as access to transportation alternatives like bike routes or employer-organized transportation (vanpools, shuttles). 2. "Cardiovascular disease" is broad and well-tracked, but other health-related metrics could draw a fuller picture. Asthma correlates strongly to air quality, and would definitely be appropriate for this list. Reduction of asthma rates would link directly to quantifiable benefits. 3. Related to health and quality of life, food access and diet concerns – proximity to full-service grocers, cost of food relative to average income, obesity as a health risk – could also be added. ii. Historical inequities and patterns of institutional action to the detriment of vulnerable populations persist, and are visible quantitatively in many of the metrics floated by the company. Practices such as redlining may be visible in housing burden data, for example. From a qualitative perspective, the unique history of PSE's service territory could inform the unique types of equity concerns PSE could ameliorate through its CETA-prompted actions, or inform the specific actions themselves. c. Are there other quantifiable economic or equity measures that should be included? i. Other than factoring cost-of-living at as granular a level as is practicable, the economic metrics the company has proposed seems like a good place to start. d. What other metrics should be applied? i. No other considerations at this time. e. Are there other quantifiable reliability, energy security and resiliency measures that can be included in the assessment? i. The proliferation of distributed energy resources around PSE's service area will have an impact on reliability. It is likely that DERs which enhance reliability will be adopted by more affluent customers – resources that may not be nearly as accessible to HICs and VPs. To the extent PSE can include some aggregate measure of technologies like PV, EVs, and small-scale battery storage, the company will be	Thank you for providing thoughtful answers to the presentation prompts. PSE will take these suggestions under advisement as we continue to develop and refine the Economic, Health and Environmental Benefits Assessment and progress the CEAP and CEIP.

Feedback Form Date	Stakeholder	Comment	PSE Response
		able to see the inequitable distribution of these resources. This should be easy, too, as DER assessments are also required under CETA.	
11/30/2020	Kyle Frankiewich, Washington Utilities and Transportation Commission	**Content of the draft IRP**: While staff supports the continued engagement of the IRP advisory group after the IRP draft is filed, staff shares the concerns of other stakeholders that key parts of the IRP analysis may not be finished in time for inclusion in the draft IRP. Specifically, the broader exploration of flexibility and stochastic risk analysis of the company's (draft) preferred portfolio may not be available for thorough review by stakeholders prior to its completion in the IRP due in April. The IRP must evaluate changes to achieve, among many other constraints, the requirements of CETA at least reasonable cost, considering risk. The risk component implies some stochastic analysis of the preferred portfolio.	PSE acknowledges your concerns and is working to include all the analysis conducted to date in the draft IRP, due January 4, 2021. PSE looks forward to stakeholder feedback on the draft. PSE will host two more public participation meetings in 2021 before the final IRP to review the remaining analysis and obtain stakeholder feedback.
11/30/2020	Virginia Lohr, Vashon Climate Action Group	On Slide 19, I want to address Irena Netik's oral comments regarding public participation in the IRP Advisory Group (on the Nov. 16, 2020 Webinar recording from 29:38 to 31:41). My understanding of what she said is that PSE decided to have a very open process for the 2021 IRP and considered anyone who attended one of the IRP webinars to be part of the 2021 IRP Advisory Group. I have really appreciated this openness and the broad acceptance of who may participate. She also mentioned that this process was selected because it appeared to be where the rules for future IRPs were headed. She suggested that there was not full clarity in what the final rules will ultimately say. I want to express my hope that PSE will continue with this broad understanding of who may participate on the IRP Advisory Group in the future, regardless of what the rules say, assuming the rules are setting minimum requirements that PSE could exceed. The 2021 IRP process has been much more welcoming of participation than the 2019 IRP, which felt more exclusionary. I assume it was not intended, but the closed nature of 2019 IRP process contributed to some people's impressions that PSE was trying to hide information from the public.	Thank you for your feedback and sharing your support of the inclusive nature of the 2021 IRP public participation process. Thank you for your suggestions concerning public participation in PSE's future IRPs.
11/30/2020	Virginia Lohr, Vashon Climate Action Group	Please continue your inclusion of all interested people as participants in future IRP Advisory Groups.	PSE welcomes all interested people as participants in the 2021 IRP process. Thank you for your continued participation!

PSE IRP Consultation Update

Webinar 10: Clean Energy Action Plan (CEAP) and Clean Energy Implementation Plan, Economic, Health and Environmental Benefit Assessment of Current Conditions and Delivery System and Grid Modernization Needs

November 16, 2020

12/14/2020

The following consultation update is the result of stakeholder suggestions gathered through an online Feedback Form, collected between November 9 and November 30, 2020 and summarized in the December 7 Feedback Report. The report themes have been summarized and along with a response to the suggestions that have been implemented. If a suggestion was not implemented, the reason is provided.

Economic, Health and Environmental Benefits Assessment

PSE received feedback from Don Marsh (CENSE), Brian Grunkemeyer (FlexCharging), David Perk (350 Seattle) and Kyle Frankiewich (WUTC Staff) regarding PSE's intial approach for the Economic, Health and Environmental Benefits Assessment.

PSE has reached out to Brian Grunkemeyer to discuss some of the details of the avoided tailpipe emissions dataset and some intitial information was exchanged on December 8. A meeting will be arranged for later in December or early January to learn more.

PSE thanks stakeholders for their thoughtful review and suggestions and will endeavor to adopt the following suggestions in development of the Economic, Health and Evironmental Benefits Assessment:

1. Coordination with local advocacy groups
2. Inclusion of air quality metrics in the assessment
3. Parallel assessment of named communities and metric evaluation
4. Continued evaluation and refinement of assessment metrics and metholologies to best capture distributions of named communities

Scope of PSE's Draft IRP

James Adock and Kyle Frankiewich (WUTC Staff) provided feedback of concerns regarding the scope of PSE's 2021 Draft IRP, due January 4, 2021. While not all the analysis will be completed for the draft IRP, PSE is confident that stakeholders will have meaningful content for review and feedback. PSE fully intends to incorporate stakeholder feedback on the draft IRP received during the WUTC comment period that is expected to begin in early January. In addition, PSE will continue with its public participation process and stakeholders will have opportunity to provide feedback on analysis that is completed after the draft IRP is filed. PSE is committed to documenting stakeholder feedback and demonstrating its application in the IRP analyses.

Summary of all updates

PSE appreciates the feedback provided by stakeholders. In summary, the following changes will be implemented:

- PSE will work to adopt the four stakeholder suggestions above in the Economic, Health and Evironmental Benefits Assessment as practical.
- PSE will work to develop a draft IRP with key analyses, scenarios and sensitivies completed for stakeholder review and feedback. The draft IRP will be available at www.pse.com/irp on January 4, 2021.

PSE PUGET SOUND ENERGY

Webinar #11: Flexibility analysis & Portfolio draft results

12/16/2020

Overview

On December 15, 2020 Puget Sound Energy hosted an online meeting with stakeholders to discuss the Flexibility analysis and Portfolio draft results. Additionally, participants were able to ask questions and make comments using a chat box provided by the Go2Meeting platform.

Below is a report of the questions submitted to the chat box. Answers to the questions were provided verbally by IRP staff during the webinar. Please note that questions were answered in order of relevance to the topic currently being discussed. Questions regarding other topics were answered at the end of the webinar session.

To view a recording of the webinar and to hear responses from staff, please visit the project website at pse-irp.participate.online.

Attendees

A total of 79 stakeholders and PSE staff attended the webinar, plus another 9 attendees who called into the meeting and did not identify themselves (88 people total).

Attendees included: Alison Peters, Andrew Padula, Anne Newcomb, Barret Stambler, Bill Donahue, Bill Westre, Bob Stolaski, Bob Williams, Brett Rendina, Brian Tyson, Brian Grunkemeyer, Bruce Boram, C Bunch, Camerson Yourkowski, Cathy Koch, Charlie Black, Charlie Inman, Cody Duncan, Corey Kupersmith, Corina Pfeil, Court Olson, Cuong Nguyen, David Meyer, David Tomlinson, Diann Strom, Dillon Stambler, Don Marsh, Doug Howell, Elise Johnson, Elizabeth Hossner, Elyette Weinstein, Eric Markell, Fred Heutte, Gurvinder Singh, Horea Catanase, Irena Netik, James Adcock, Jennifer Magat, Jessica Raker, John Fazio, Jon Piliaris, Joni Bosh, Kara Durbin, Katherine Kissinger, Katie Ware, Kendra White, Kelly Xu, Kevin Jones, Kyle Frankiewich, Larry Becker, Leslie Carlson, Lori Elworth, Lorin Molander, Mark Lenssen, Matthew Shapiro, Michele Kvam, Nate Sandvig, Norm Hansen, Patrick Leslie, Rahul Venkatesh, Rob Briggs, Ron Roberts, Ryan Sherlock, Sarah Laycock, Scott Thomas, Scott Williams, Stephanie Chase, Steve Greenleaf, Therese Miranda-Blackney, Tom Eckman, Tracy Rolstad, Tyler Tobin, Virginia Lohr, Virginia Wiseman, Warren Halverson, Wendy Gerlitz, Wiemin Dang, Zac, and Zhi Chen

Questions Received

Questions from attendees are posted in the order in which they were received. The webinar began at 1:00 PM PDT and ended at 5:00 PM PDT.

Name	Time Sent	Comment
Don Marsh	**1:03 PM**	I'm aware of people waiting to get into the meeting.
Virginia Lohr	**1:03 PM**	The ink you sent out is not working!
Virginia Lohr	**1:04 PM**	The LINK does not work
Elise Johnson	**1:05 PM**	Hi Virginia! Is this the meeting link you're referring to?
Virginia Lohr	**1:05 PM**	The link sent out if your registered is wrong and says waiting for host to open. that is probably where people are waiting.
Don Marsh	**1:07 PM**	Court Olson and Fred Heutte have not been able to join.
Kyle Frankiewich	**1:07 PM**	the link on PSE's public-facing IRP website worked for me: **https://pse-irp.participate.online/get-involved**
Virginia Lohr	**1:07 PM**	https://global.gotomeeting.com/join/413142693. This is the bad link you sent out.
James Adcock	**1:08 PM**	How about this one: https://global.gotomeeting.com/join/255497885
Alison Peters	**1:09 PM**	Yes, James. That's the right link.
Michele Kvam	**1:09 PM**	Thank you, Jim! That is the correct link.
Elise Johnson	**1:09 PM**	Thanks for letting us know, all. We will send out an email with the correct link ASAP.
Doug Howell	**1:12 PM**	Would you please make note when there are changes in the slides that were release last week versus what is being used today?
James Adcock	**1:13 PM**	Whether or not I had a proper amount of time to develop my questions, I did ask a lot of question, because the slides for this meeting I found to be particularly confusing. I hope you will actually answer my questions so that we can all attempt to answer your slides.
Elise Johnson	**1:14 PM**	An email is now being sent with the correct link. Thank you, all!
James Adcock	**1:14 PM**	Sorry "so we call all attempt to *understand* your slides."
Elise Johnson	**1:18 PM**	Hi Doug! The slide deck being used today can now be found on the PSE IRP website at the following link: https://oohpseirp.blob.core.windows.net /media/Default/2021/meetings/December_15_Webinar/Webinar%2011 %20-%20Presentation.pdf
Kyle Frankiewich	**1:21 PM**	slide 15: I'm guessing that when the bars are higher than the CETA target, that represents overgeneration that comes with lots and lots of renewables. Is this correct?
Joni Bosh	**1:23 PM**	slide 16. Please repeat - does the red represent new peak gas plants?
Kyle Frankiewich	**1:23 PM**	slide 16: Is the NG in 2045 within line losses or why is there still NG in 2045?
Joni Bosh	**1:25 PM**	18 DOes the carbon price include the SCGHG?
Kyle Frankiewich	**1:26 PM**	slide 18: is this out-of-model or are RECs pinned to the CA market forecast selectable within the LTCE model?
James Adcock	**1:27 PM**	Slide 18 Question: Given that California is a "Double Counting" state that does not require the retirement of RECs used for "government mandates" -- unlike the definition of "RECs" used in CETA and by the EPA, why does it make sense to use Californian Carbon Prices? Shouldn't the use of Californian [fake] RECs be prohibited for CETA purposes? Shouldn't the price of "Real" RECs -- RECs meeting the definitional requirements of CETA and the EPA -- be higher in price?

James Adcock	**1:30 PM**	Slide 16 Question: Where do you think you can get that much Biomass ???
Fred Heutte	**1:30 PM**	On slide 16: what resources are included in "peaking capacity"
Kyle Frankiewich	**1:33 PM**	Elise, I think you may have missed Joni's and my Qs on slide 16
Kyle Frankiewich	**1:33 PM**	i'm comfortable coming back at the next pause
Charlie Black	**1:35 PM**	What price forecast for CARB GHG emissions allowances did PSE use?
Don Marsh	**1:35 PM**	Question on slide 21. Why are the numbers for DR and DER so tiny?
Don Marsh	**1:36 PM**	Those numbers seem very small compared to other utilities pursuing DR and DER.
Anne Newcomb	**1:37 PM**	Can more wind come online sooner? Before 2025?
Doug Howell	**1:37 PM**	How maximize existing gas instead of acquiring new?
R. C. Olson	**1:38 PM**	Are you assuming Market resources are fossil based?
James Adcock	**1:39 PM**	Slide 23 Question: You are showing a hypothetical future load "Jan 2 - Jan 4 2030" -- how exactly are you creating this future hypothetical load schenario?
Brian Grunkemeyer	**1:39 PM**	Slide 23: How can we be sure the market will be there if there is a substantial cold event affecting say most of the state? And would DR be your preferred option to meet peaking capacity?
Don Marsh	**1:40 PM**	I have a number of questions on slide 23. Best to ask them interactively I think.
Nate Sandvig	**1:40 PM**	How much of this market is out of region?
Bill Westre	**1:40 PM**	S-23 You currently have nearly 200MW of CCCT and peaker power. What justifies the new paekers?
Alison Peters	**1:40 PM**	Question from Nate S; how much of market is out of region?
Bill Westre	**1:41 PM**	S-24 I meant 2000MW
Nate Sandvig	**1:41 PM**	Is PG&E exchange agreement in these numbers?
Doug Howell	**1:41 PM**	Slide 24. If conservation does not assume a 6-year ramp verus a 10-year ramp rate, what is the additional contribution?
Doug Howell	**1:42 PM**	Now that PSE sale of Colstrip Unit 4 is happening, what does the new analysis say of Colstrip economics right now. The sale proceeding seem to reveal that Colstrip is not economic now.
Doug Howell	**1:43 PM**	* Colstrip sale NOT happening
Nate Sandvig	**1:45 PM**	based on PGE experience, given building new natural gas is extremely difficult if not impossible, what is scenario plan in the alternative?
Fred Heutte	**1:45 PM**	Slide 23: how frequent are extended duration events such as the one shown here happening in the modeling overall. Is it about 1 per year or something else?
Fred Heutte	**1:46 PM**	Slide 23: what is the cost of additional gas transportation and firm gas or other contractual provisions to provide gas to ride through long duration events?
Doug Howell	**1:48 PM**	Montana wind - you have about 350 MW of freed up Unit 1 and 2 so why couldn't you bring in Montana wind right now?
Doug Howell	**1:49 PM**	MW of transmission

Fred Heutte	**1:51 PM**	Just to note on market availability, PacifiCorp has documented that Mid-C transaction volume has fallen by about half since 2016, potentially related to the increase in EIM participation.
Fred Heutte	**1:56 PM**	my understanding is that gas can be held as spinning reserve if it's not being used for market dispatch
Brian Grunkemeyer	**1:56 PM**	Slide 23: Why is there no DR in this picture?
Fred Heutte	**1:56 PM**	correction, "market dispatch" better said as "dispatch to load" in the single-utility context
R. C. Olson	**1:59 PM**	Why did the model pick new peaker capacity and not add demand response capacity instead?
Alison Peters	**2:01 PM**	And we will move any leftover q's to the Feedback Report if we still have some at 5pm. Thank you.
James Adcock	**2:05 PM**	Slide 26 Question: I don't understand "I. SCGHG ..." -- can you please clarify what you are talking about here?
Kyle Frankiewich	**2:06 PM**	Slide 26: I understand that N, O, and one of the other ones are not actually included in this presentation. May want to correct the slide header
Alison Peters	**2:07 PM**	A friendly reminder to please stay on mute while speakers are presenting. Thank you.
Kevin Jones	**2:07 PM**	Slide 26 - Did PSE publish the results of the sensitivity voting? How many votes did sensitivity N receive?
Joni Bosh	**2:07 PM**	slide 27 - where are the actual values used for mid low and high found? Which previous presentation?
R. C. Olson	**2:09 PM**	How can PSE model conservation as a controlled variable? Conservation is happing outside of PSE control.
Elise Johnson	**2:10 PM**	Hi Kevin! Yes, this was published in Consultation Update #9: **https://pse-irp.participate.online/consultation-updates**
Tom Eckman	**2:10 PM**	Slide 28 - Was the amount of available conservation available less than the mid for the low forecast and more for the high forecast, given that you said there were lower and higher levels of population growth in thse forecast?
Eric Markell	**2:11 PM**	What project financing assumptions underlie assumed availability of MT and WY wind? Is assumed availability bi-lateral long term contracgts or merely Mid C spot purchases?
James Adcock	**2:12 PM**	Slide 29 Question: Can you define "Annual Portfolio Costs" -- is this really "Annual" costs or is "Cumulative" Portfolio costs?
Elyette Weinstein	**2:16 PM**	Please add the answer to Joni's question to slide 27. This will jelp your audience. We should not have to rifle through the October presentation, This should noyt be a challenge for you audience to make sense of the slides, especially since you have easiest and quickest access to this data.
Elise Johnson	**2:20 PM**	Hi Elyette! The October presentation can be found here: https://oohpseirp.blob.core.windows.net/media/Default/2021 /meetings/Oct_20_webinar/Webinar%209%20-%20Electric%20IRP%20Presentation.pdf
James Adcock	**2:26 PM**	Slide 31: I'm trying to understand battery storage being displayed as a negative number. I understand that when battery charges it represents a negative number, but when it discharges it represents a positive number, so shouldn't it also be displayed "above the line" -- above the zero mark?

Charlie Black	**2:29 PM**	Did I hear Elizabeth say today that all market power purchases are treated as unspecified energy? If so, does this mean that it is assumed PSE is only using owned and contracted renewables for CETA compliance?
Charlie Black	**2:29 PM**	This question is relevant for the overgeneration analysis.
Anne Newcomb	**2:30 PM**	Was a sensitivity run that uses excess energy to create Hydrogen?
Kyle Frankiewich	**2:30 PM**	oh, this is because the units are in aWM, and batteries don't 'make' MWhs.
Doug Howell	**2:32 PM**	Slide 35. Would you confirm that you currently have about 350 MW of TX capacity from the closure of Colstrip Units 1 and 2?
Eric Markell	**2:34 PM**	To All: What project financing assumptions underlie assumed availability of MT and WY wind? Is assumed availability bi-lateral long term contracgts or merely Mid C spot purchases?
Kyle Frankiewich	**2:37 PM**	slide 36: did PSE do this analysis for its rerouting of some Tx rights from PSE-owned wind projects to MidC?
Doug Howell	**2:37 PM**	So PSE could bring in some new Montana wind now.
James Adcock	**2:38**	Slide 37 Question: Can transmission still be "shared" when there is little conflict -- for example when Battery Storage and Wind are on the same Transmission "Stub Line" -- where battery will charge from Wind when Wind runs, and therefore actually represent a negative load on the Transmission stub line?
Kyle Frankiewich	**2:38 PM**	or, how does this analysis differ from that resource decision?
James Adcock	**2:44 PM**	Comment: The reason I asked was that PSE previously showed Battery costs (incorrectly I believe) including the costs of a 10 mile long dedicated stub line for that battery -- when that is NOT how your competitors are building Battery Storage -- rather they are building Battery Storage where additional new transmission line dedicated to that Battery Store *Is Not* needed.
Doug Howell	**2:46 PM**	Slide 38. Why isn't SCGHG when treated as an externality included in the dispatch model?
James Adcock	**2:48 PM**	Slide 39 Question: So am I understanding correctly, if PSE models SCGHG as a dispatch cost -- as many people have called for PSE to do -- then fewer new Natural Gas Peakers are required to be built?
James Adcock	**2:50 PM**	Does a phone user perhaps not have their phone on mute?
Eric Markell	**2:51 PM**	Slide 41 Does "retirement" mean deconstruction and site restoration? Are those entire costs included in your costing methodology?
Tom Eckman	**2:52 PM**	Slide 38 - Since the SCC is not applied to the hourlly dispatch cost, this sensitivity appears to only impact resource selection, but not resource dispatch. Is that correct? If so, it doesn't seem to test whether including SCC in dispatch cost would futher reduce GHG emissions due to lower fossil resource utilization.
Don Marsh	**2:53 PM**	Slide 42. Can you remind us why batteries have only 12.4% ELCC?
Nate Sandvig	**2:53 PM**	slide 41, you say “batteries,” did you look at pumped storage?
Joni Bosh	**2:54 PM**	! to tom eckman's question.
Doug Howell	**2:58 PM**	Please respond to Tom Eckman's question about SCGHG and dispatch modeling.

James Adcock	**3:02 PM**	Slide 47 Question: My understanding is that the 2% cost cap limit "offramp" possibility does not exist prior to 2030 -- i.e. that PSE is strictly required to meet "80% in 2030." Is this PSE's understanding also, or does PSE believe that they can use the 2% 'offramp" prior to 2030?
Doug Howell	**3:04 PM**	Yes, it was understood that modeling needs to be in dispatch
Doug Howell	**3:04 PM**	When with the results of SCGHG in dispatch modeling be available?
James Adcock	**3:08 PM**	If PSE is going to answer questions in a future report, can PSE answer the questions *specifically* rather then lumping them all together and answering generically in a way that perhaps makes sense to PSE, but which doesn't make any sense to the people who actually asked the questions?
Joni Bosh	**3:09 PM**	No
James Adcock	**3:10 PM**	Riase hand
Brian Grunkemeyer	**3:11 PM**	raise hand
Kyle Frankiewich	**3:11 PM**	raised hand
Elise Johnson	**3:12 PM**	Hi James! Refering to your question on feedback reports - the feedback reports do answer the questions with line-by-line answers. For an example, you can refer to one of the reports: https://oohpseirp.blob.core.windows.net /media/Default/2021/meetings/Oct_20_webinar/Webinar%209%20-%20Electric%20IRP%20Feedback%20Report.pdf
James Adcock	**3:13 PM**	+1 “Smart Water Heaters.”
Eric Markell	**3:14 PM**	What is the general order of magnitude of increased credit that wil be required of PSE to proivide to market resources as purchased power to replace Colsgtrip and Centrailia and CCCTs
Kevin Jones	**3:16 PM**	Could you answer Kyle's question: Slide 48 - For the no CETA case, how is this cost not $0?
Charlie Black	**3:16 PM**	Agree with Kyle Frankiewich about showing the social costs of GHG emissions, valued at the SCGHG.
Kyle Frankiewich	**3:37 PM**	slide 56: what do the inputs look like for intermittent resources?
Kyle Frankiewich	**3:40 PM**	slide 56: relatedly, where does the variance to forecast occur for wind and solar? I would guess the last two steps, but some clarification would be helpful.
Brian Grunkemeyer	**3:41 PM**	Slide 57: The DR call restrictions are exactly why PSE should model Demand Flexibility resources as a new type of conservation measure.
James Adcock	**3:43 PM**	Slide 58 Question: Why are you seeing so much unexpected "Night Hour" variability in the Dec. 30 Example?
Kyle Frankiewich	**3:43 PM**	slide 57: do the attributes of DR align with CPP, or some other DR resource? I understand taht demand resources like water heaters can be callable multiple times a day without perceivable performance impacts to end users. These would presumably have a lot more value to this modeling goal than a lumpy DR program as shown.
Fred Heutte	**3:45 PM**	slide 55: "When the model must flex generation up, it can turn on dispatchable plants, discharge batteries, or buy power from the market." Can the model not also dispatch DR?

Zhi Chen	**3:45 PM**	PSE is using NREL data for wind and solar resources as the inputs in PLEXOS. Same input source as Aurora and the resource adequacy model.
James Adcock	**3:47 PM**	Slide 60 Question: Why wasn't Battery Storage included in this analysis?
Kyle Frankiewich	**3:47 PM**	slide 60: are the purchases and sales connected to the energy imbalance market? Seems like the EIM is a big intra-hour market that could lower costs or increases benefits for these types of problems
Tom Eckman	**3:51 PM**	Since it was stated earlier that conservation significantly reduced the amount of renewables needed to meet CETA, how is this benefit captured in the flexibility analysis, since it impacts the amount of balancing reserves needed?
Eric Markell	**3:51 PM**	Slide 62 Is the PSE staff aware of any specific site in the PNW where a utility scale pumped hydro project could be permitted, constructed and financed?
Zhi Chen	**3:51 PM**	The model has the CAISO EIM engine. But no EIM transactions so far. PSE could add the market players later on. All market purchases and sales (DA, ID, and IH) connected to the Mid C market so far.
James Adcock	**3:52 PM**	Slide 63 Question: Sorry I reallly don't understand what you are talking about in this slide. Can you go over it again in more detail to I can try to understand it?
Don Marsh	**3:53 PM**	Raise hand
Nate Sandvig	**3:53 PM**	lot of opportunities to comment with what you are asking from stakeholders due dec 28 over the Holidays. can we get a week extension at a minimum?
Nate Sandvig	**3:53 PM**	“heavy”
Charlie Black	**3:53 PM**	How do PSE's draft results on flexibility analysis compare with other utilities' IRP analyses?
Kyle Frankiewich	**3:54 PM**	re: other resources - PAC's 2019 IRP process explored a number of approaches to countenancing the value of dispatchable resources. Some were more palatable for stakeholders than others, but all were worth reviewing.
Tom Eckman	**3:54 PM**	PacifiCorp is using PLEXOS to evaluate the value of ancillary services, including balancing reserves.
Fred Heutte	**3:56 PM**	And in fact they are now using Plexos as their primary IRP model, replacing System Optimizer.
Fred Heutte	**3:56 PM**	These days Plexos is more of a model ecosystem than a core model.
Brian Grunkemeyer	**4:02 PM**	About your flexibility analysis, I thought your 2017 numbers were very low. But I had no comparison point to prove it, short of an anecdote from SRP saying they only had 150 MW of ramp capability.
Matthew Shapiro	**4:04 PM**	Also in pumped storage is the proposed Badger Mountain project in Douglas County, at the Mid-C hub. 500 MW.
Brian Grunkemeyer	**4:08 PM**	Elizabeth, on flexibility, SRP several years ago was considering a mix of demand response, demand flexibility (from electric vehicles), and maybe new generation to increase their ramp rate. Flexibility is cheap is you have it, but if you don't have it and need to build a new power plant, it's not free.
Brian Grunkemeyer	**4:09 PM**	This is made worse by CAISO market restrictions on DR. Basically, you need ramp to get ramp. It's a chicken and the egg problem.
Fred Heutte	**4:19 PM**	slide 70: it's a little hard to tell with the coloring, how much is JP & redelivery, and how much is Tacoma LNG

Don Marsh	**4:19 PM**	Slide 70: the relatively flat dashed line starts to increase in 2032. Is this because the 10-year ramp rate has expired?
C Bunch	**4:34 PM**	Like CA, many cities in WA are looking at gas expansion regulation. How is regulation factored into sensitivities analysis or demand?
Rob Briggs	**4:50 PM**	Would you please clarify Gurvinder's answer to the question on sensitivity analyses of new regulation of new gas hookups or the impact of electrification trends. Is there a sensitivity analysis coming as part of the 2021 IRP that will examine that potentially very significant trend?

2021 PSE Integrated Resource Plan

B Legal Requirements

This appendix identifies where each of the regulatory requirements for the electric and natural gas integrated resource plans is addressed within the IRP and reports on the progress of the 2017 IRP electric and natural gas utility action plans, the last IRP filed. It also delivers two additional reports.

Contents

1. CLEAN ENERGY TRANSFORMATION ACT (CETA)

On May 7, 2019, Governor Jay Inslee signed into law the Clean Energy Transformation Act (CETA), which commits Washington to an electricity supply free of greenhouse gas emissions by 2045. The CETA applies to all electric utilities serving retail customers in Washington (such as PSE) and sets specific milestones to reach the required 100 percent clean electricity supply. The first milestone is in 2022 [as of the draft filing date of January 4, 2021 the draft rules state the milestone is October 2021], when PSE must prepare and publish a clean energy implementation plan with its own targets for energy efficiency, demand response and renewable energy.

By the end of 2025, PSE must eliminate coal-fired electricity from its state portfolios. The first clean energy standard applies in 2030. The 2030 standard is greenhouse gas neutral, which means that PSE will have the flexibility to use limited amounts of electricity from greenhouse gas emitting resources if those resources are offset by other actions, such as procurement of renewable energy credits. By 2045, PSE must supply customers in Washington with electricity that is 100 percent renewable or non-emitting, with no provision for offsets.

Coal Phase-out Requirement

The CETA requires PSE to eliminate coal-fired resources from its allocation of electricity sold to retail customers in its service territory by December 31, 2025. For the purposes of this standard, a "coal-fired resource" does not include:

- an electric generating facility that is subject to an obligation to meet the state's Greenhouse Gas Emissions Performance Standard (i.e., the TransAlta Centralia Coal Plant); or
- an electric generation facility that is included as part of certain limited duration wholesale power purchases, not to exceed one month, for which the source of the power is not known at the time of entry into the transaction to procure the electricity (i.e., short-term transactions of undifferentiated electricity).

The Washington Utilities and Transportation Commission (Commission) must accelerate depreciation for any coal-fired resource owned by PSE and is allowed to accelerate depreciation for any qualified transmission line to no later than December 31, 2025. Additionally, the Commission must allow in rates prudently incurred undepreciated investments in a fossil-fuel generating resource that has been retired from service under specific conditions.

Greenhouse Gas Neutral Standard (January 1, 2030 - December 31, 2044)

The CETA will require PSE to make all retail sales of electricity to Washington customers greenhouse gas neutral for multi-year compliance periods beginning January 1, 2030, and ending December 31, 2044. To achieve compliance with this standard, PSE must:

- pursue all cost-effective, reliable, and feasible conservation and efficiency resources and demand response resources to reduce or manage electric retail load; and
- use electricity from renewable resources and non-emitting electric generation (or alternative compliance options, discussed below) in an amount equal to 100 percent of PSE's average annual retail electric load over each multiyear compliance period.

All renewable resources used to meet the compliance obligation must be verified using renewable energy credits and must be tracked and retired in the tracking system selected by the Department of Commerce. Non-emitting generation resources used to meet the obligation must be generated during the compliance period and must be verified by documentation that PSE owns the non-power attributes of the electricity.

In complying with the greenhouse gas neutral standard and clean energy standard, PSE may not use hydroelectric generation that requires new diversions, impoundments, bypass reaches or expansion of existing reservoirs, unless otherwise required for the operation of a pumped storage facility. PSE may, however, make efficiency or other improvements to its existing facilities and may install hydroelectric generation in pipes, culverts, irrigation canals and other manmade waterways. Nothing in the greenhouse gas neutral or clean energy standards prohibits PSE from purchasing from or exchanging power with the Bonneville Power Administration (BPA).

Alternative Compliance Option

PSE may satisfy up to 20 percent of the greenhouse gas neutral standard with an alternative compliance option for the greenhouse gas neutral standard compliance period beginning January 1, 2030 and ending December 31, 2044. An alternative compliance option includes any combination of the following:

- making an alternative compliance payment in an amount equal to the administrative penalty discussed below;
- purchasing unbundled renewable energy credits;
- investing in energy transformation projects associated with the consumption of

energy in Washington and that meet criteria and quality standards developed by the Department of Ecology, in consultation with the Department of Commerce and the Commission; or

- using electricity from an energy recovery facility using municipal solid waste as the principal fuel source, where the facility was constructed prior to 1992 and is in compliance with federal and state air quality standards.

Administrative Penalty

If PSE were to fail to comply with the coal phase-out or carbon neutral standards, PSE must pay an administrative penalty equal to the product of 1) $100/MWh of emitting or unspecified electric generation used to meet PSE's retail electric load times 2) the following multipliers

- 1.5 for coal-fired resources;
- 0.84 for gas-fired peaking power plants; and
- 0.60 for gas-fired combined-cycle power plants.

The penalty is adjusted for inflation, beginning in 2027. Beginning in 2040, the Commission may increase the penalty for PSE to accelerate compliance.

The Commission may relieve PSE of its penalty obligation under the greenhouse gas neutral standard if it finds that PSE's compliance is likely to result in conflicts with or compromises to its obligation to comply with North American Electric Reliability Corporation (NERC) reliability standards, violate prudent utility practice for assuring resource adequacy, compromise the power quality or integrity of its system, or due to factors reasonably outside PSE's control. Additionally, the Governor may waive a penalty by declaring an energy emergency under current law, if the Department of Commerce's report demonstrates adverse system reliability impacts due to implementation of the coal phase-out or greenhouse gas neutral standards.

Clean Energy Standard (Beginning January 1, 2045)

By January 1, 2045, PSE must meet 100 percent of its retail electric load to Washington customers using non-emitting electric generation and electricity from renewable resources. The Commission, the Department of Commerce, the Energy Facility Site Evaluation Council, the Department of Ecology and all other state agencies must incorporate this standard into all relevant planning and use all statutory programs to achieve the standard.

In planning to meet projected demand, PSE must, consistent with the requirements of the Energy Independence Act, pursue all cost-effective, reliable, and feasible conservation efficiency resources, and demand response. In making new investments, PSE must, and to the maximum extent feasible, 1) achieve targets at the lowest reasonable cost; 2) consider acquisition of surplus renewable resources; and 3) rely on renewable resources and energy storage in the acquisition of new resources.

Energy Resource Planning

Integrated Resource Plans and the Clean Energy Action Plan

The CETA requires PSE to consider the following elements in its Integrated Resource Plans:

- an assessment and 10-year forecast of the availability of regional generation and transmission capacity on which PSE may rely to provide and deliver electricity to its customers;
- a determination of resource adequacy metrics for the resource plan consistent with the forecasts;
- a forecast of distributed energy resources that may be installed by PSE's customers and an assessment of their effect on PSE's load and operations;
- an assessment, informed by the Department of Health's Cumulative Impact Analysis, "of energy and nonenergy benefits and reductions of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits, costs and risks; and energy security and risk;";and
- a 10-year Clean Energy Action Plan for implementing the coal phase-out standard, the greenhouse gas neutral standard, and the clean energy standard at the lowest reasonable cost, and at an acceptable resource adequacy standard, that identifies the specific actions to be taken by PSE consistent with the long-range IRP.

The CETA requires PSE to consider the social cost of greenhouse gas emissions when developing its Integrated Resource Plan and Clean Energy Action Plan. PSE must incorporate the social cost of greenhouse gas emissions as a cost adder when evaluating and selecting conservation policies, programs and targets and evaluating and selecting intermediate-term and long-term resource options. The cost of greenhouse gas emissions resulting from the generation of electricity is equal to the cost per metric ton of carbon dioxide equivalent emissions, using the 2.5 percent discount rate published by the United States government Interagency Working Group on the Social Cost of Greenhouse Gases.

Clean Energy Implementation Plan

By January 1, 2022, and every four years thereafter, the CETA requires PSE to develop and submit to the Commission 1) a four-year Clean Energy Implementation Plan for the greenhouse gas neutral standard and clean energy standard and 2) proposed interim targets for meeting the greenhouse gas neutral standard during the years prior to January 1, 2030, and for the period beginning on January 1, 2030 and ending on December 31, 2044.

The Clean Energy Implementation Plan must

- be informed by PSE's Clean Energy Action Plan and
- identify specific actions to be taken by PSE over the next four years, consistent with PSE's Integrated Resource Plan and resource adequacy requirements, that demonstrate progress toward meeting (i) the interim targets proposed along with the clean energy implementation plan, (ii) the greenhouse gas neutral standard, and (iii) the clean energy standard.

The specific actions identified in the Clean Energy Implementation Plan must be informed by PSE's historic performance under median water conditions and resource capability and its participation in centralized markets. In identifying specific actions in its Clean Energy Implementation Plan, PSE may also take into consideration any significant and unplanned loss or addition of load it experiences.

The Commission, after a hearing, must by order approve, reject, or approve with conditions PSE's Clean Energy Implementation Plan and interim targets. The Commission may, in its order, recommend or require more stringent targets than those proposed by PSE. The Commission may periodically adjust or expedite timelines if it can be demonstrated that the targets or timelines can be achieved in a manner consistent with the following:

1. maintaining and protecting the safety, reliable operation, and balancing of the electric system;
2. planning to meet the standards at the lowest reasonable cost, considering risk;
3. ensuring that all customers are benefiting from the transition to clean energy; and
4. ensuring that no customer or class of customers is unreasonably harmed by any resulting increases in the cost of PSE-supplied electricity as may be necessary to comply with the standards.

CETA Rulemakings

The Commission must adopt rules under the CETA by January 1, 2021. The Commission is encouraged to coordinate and consult with other agencies in developing rules. At the time of preparing this draft IRP, a number of Commission-led rulemakings are under development: 1) the Purchase of Electricity rulemaking; 2) the Integrated Resource Plan and Clean Energy Implementation Plan rulemaking; and the 3) the Energy Independence Act rulemaking.[1]

The Department of Commerce must adopt rules establishing reporting requirements for utilities to demonstrate compliance with the coal phase-out, greenhouse gas neutral and clean energy standards. These rules are anticipated to be complete by January 1, 2021.

The Department of Ecology must adopt rules, in consultation with the Commission and the Department of Commerce, to establish requirements for energy transformation project investments, as well as the emissions rate for unspecified electricity, by January 1, 2021.

Finally, the Department of Health must prepare a cumulative impact analysis to designate the communities highly impacted by fossil fuel pollution and climate change in Washington by December 31, 2020.

1 / The rulemaking section of Appendix B may be revised for the final IRP to reflect the final rules.

2. REGULATORY REQUIREMENTS

Figure B-1 lists the statutory requirements in the CETA that apply to electric IRPs. Figures B-2 and B-3 list the regulatory requirements codified in WAC 480-100-238 and WAC 480-90-238 that apply to electric and natural gas integrated resource plans.[2] These tables identify the chapters and appendices of this plan that address each requirement. Figure B-4 details an additional condition pursuant to WUTC Order 01, dated April 13, 2017 in PSE's 2017 docket. Other conditions in Order 01 were addressed in the 2017 IRP. Figure B-5 details natural gas utility requirements pursuant to HB 1257.

Figure B-1: Electric Utility Integrated Resource Plan Regulatory Requirements in the CETA

Statutory or Regulatory Requirement	Chapter and/or Appendix
RCW 19.280.030 (1) (a) A range of forecasts, for at least the next ten years or longer, of projected customer demand which takes into account econometric data and customer usage.	Chapter 5, Key Analytical Assumptions Chapter 6, Demand Forecasts Appendix F, Demand Forecasting Models
RCW 19.280.030 (1) (b) An assessment of commercially available conservation and efficiency resources. Such assessment may include, as appropriate, opportunities for development of combined heat and power as an energy and capacity resource, demand response and load management programs, and currently employed and new policies and programs needed to obtain the conservation and efficiency resources.	Chapter 8, Electric Analysis Appendix E, Conservation Potential Assessment and Demand Response Assessment Appendix H, Electric Analysis Inputs and Results
RCW 19.280.030 (1) (c) An assessment of commercially available, utility scale renewable and nonrenewable generating technologies including a comparison of the benefits and risks of purchasing power or building new resources.	Chapter 4, Planning Environment Chapter 7, Resource Adequacy Analysis Chapter 8, Electric Analysis Appendix D, Electric Resources and Alternatives Appendix H, Electric Analysis Inputs and Results

2 / *These WAC provisions will be updated in the final IRP to reflect any changes made as a result of rules adopted in Dockets UE-191023 and UE-190698.*

Statutory or Regulatory Requirement	Chapter and/or Appendix
RCW 19.280.030 (1) (d) A comparative evaluation of renewable and nonrenewable generating resources, including transmission and distribution delivery costs, and conservation and efficiency resources using "lowest reasonable cost" as a criterion.	Chapter 3, Resource Plan Decisions Chapter 8, Electric Analysis Chapter 10, Delivery System Planning Appendix D, Electric Resources and Alternatives Appendix E, Conservation Potential Assessment and Demand Response Assessment Appendix H, Electric Analysis Inputs and Results Appendix J, Regional Transmission Resources
RCW 19.280.030 (1) (e) An assessment of methods, commercially available technologies, or facilities for integrating renewable resources, and addressing overgeneration events, if applicable to the utility's resource portfolio.	Chapter 8, Electric Analysis Appendix D, Electric Resources and Alternatives Appendix H, Electric Analysis Inputs and Results
RCW 19.280.030 (1) (f) An assessment and ten-year forecast of the availability of regional generation and transmission capacity on which the utility may rely to provide and deliver electricity to its customers..	Chapter 3, Resource Plan Decisions Chapter 7, Resource Adequacy Analysis Chapter 8, Electric Analysis Appendix J, Regional Transmission Resources
RCW 19.280.030 (1) (g) A determination of resource adequacy metrics for the resource plan consistent with the forecasts.	Chapter 1, Executive Summary Chapter 7, Resource Adequacy Analysis Chapter 8, Electric Analysis Appendix G, Electric Analysis Models Appendix H, Electric Analysis Inputs and Results
RCW 19.280.030 (1) (h) A forecast of distributed energy resources that may be installed by the utility's customers and an assessment of their effect on the utility's load and operations.	Appendix E, Conservation Potential Assessment and Demand Response Assessment Chapter 5, Key Analytical Assumptions
RCW 19.280.030 (1) (i) An identification of an appropriate resource adequacy requirement and measurement metric consistent with prudent utility practice in implementing sections 3 through 5 of CETA.	Chapter 7, Resource Adequacy Analysis Chapter 8, Electric Analysis Appendix G, Electric Analysis Models Appendix H, Electric Analysis Inputs and Results

Statistory or Regulatory Requirement	Chapter and/or Appendix
RCW 19.280.030 (1) (j) The integration of the demand forecasts, resource evaluations, and resource adequacy requirement into a long-range assessment describing the mix of supply side generating resources and conservation and efficiency resources that will meet current and projected needs, including mitigating overgeneration events and implementing sections 3 through 5 of CETA, at the lowest reasonable cost and risk to the utility and its customers, while maintaining and protecting the safety, reliability operation, and balancing of its electric system.	Chapter 1, Executive Summary Chapter 2, Clean Energy Action Plan Chapter 3, Resource Plan Decisions Chapter 5, Key Analytical Assumptions
RCW 19.280.030 (1) (k) An assessment, informed by the cumulative impact analysis conducted under section 24 of CETA of: Energy and nonenergy benefits and reductions of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits, costs, and risks, and energy security and risk.	Chapter 4, Planning Environment Appendix K, Economic, Health and Environmental Benefits Assessment of Current Conditions
RCW 19.280.030 (1) (l) A ten-year clean energy action plan for implementing sections 3 through 5 of CETA at the lowest reasonable cost, and at an acceptable resource adequacy standard, that identifies the specific actions to be taken by the utility consistent with the long-range integrated resource plan.	Chapter 2, Clean Energy Action Plan
RCW 19.208.030 (3)(a) An electric utility shall consider the social cost of greenhouse gas emissions, as determined by the commission for investor-owned utilities, pursuant to section 15 of CETA when developing integrated resource plans and clean energy action plans.	Chapter 5, Key Analytical Assumptions Chapter 8, Electric Analysis Appendix H, Electric Analysis Inputs and Results

Figure B-2: Electric Utility Integrated Resource Plan Regulatory Requirements Codified in WAC 480-100-238

Statutory or Regulatory Requirement	Chapter and/or Appendix
WAC 480-100-238 (3) (a) A range of forecasts of future demand using methods that examine the effect of economic forces on the consumption of electricity and that address changes in the number, type and efficiency of electrical end-uses.	Chapter 5, Key Analytical Assumptions Chapter 6, Demand Forecasts Appendix F, Demand Forecasting Models

Statutory or Regulatory Requirement	Chapter and/or Appendix
WAC 480-100-238 (3) (b) An assessment of commercially available conservation, including load management, as well as an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.	Chapter 8, Electric Analysis Appendix E, Conservation Potential Assessment and Demand Response Assessment
WAC 480-100-238 (3) (c) An assessment of a wide range of conventional and commercially available nonconventional generating technologies.	Chapter 8, Electric Analysis Appendix D, Electric Resources and Alternatives
WAC 480-100-238 (3) (d) An assessment of transmission system capability and reliability, to the extent such information can be provided consistent with applicable laws.	Chapter 10, Delivery System Planning Appendix J, Regional Transmission Resources
WAC 480-100-238 (3) (e) A comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation using the criteria specified in WAC 480-100-238 (2) (b), Lowest reasonable cost.	Chapter 3, Resource Plan Decisions Chapter 8, Electric Analysis Chapter 10, Delivery System Planning Appendix D, Electric Resources and Alternatives Appendix E, Conservation Potential Assessment and Demand Response Assessment Appendix H, Electric Analysis Inputs and Results Appendix J, Regional Transmission Resources
WAC 480-100-238 (3) (f) Integration of the demand forecasts and resource evaluations into a long-range (e.g., at least ten years; longer if appropriate to the life of the resources considered) integrated resource plan describing the mix of resources that is designated to meet current and projected future needs at the lowest reasonable cost to the utility and its ratepayers.	Chapter 3, Resource Plan Decisions
WAC 480-100-238 (3) (g) A short-term plan outlining the specific actions to be taken by the utility in implementing the long-range integrated resource plan during the two years following submission.	Chapter 1, Executive Summary
WAC 480-100-238 (3) (h) A report on the utility's progress towards implementing the recommendations contained in its previously filed plan.	Appendix B, Legal Requirements

Statutory or Regulatory Requirement	Chapter and/or Appendix
WAC 480-100-238 (4) Timing. Unless otherwise ordered by the commission, each electric utility must submit a plan within two years after the date on which the previous plan was filed with the commission. Not later than twelve months prior to the due date of a plan, the utility must provide a work plan for informal commission review. The work plan must outline the content of the integrated resource plan to be developed by the utility and the method for assessing potential resources.	2021 Integrated Resource Plan Work Plan filed with the WUTC April, 2020, and Updated Work Plan filed May 15, 2020, July 8, 2020, September 17, 2020, October 26, 2020 and November 19, 2020.
WAC 480-100-238 (5) Public participation. Consultations with commission staff and public participation are essential to the development of an effective plan. The work plan must outline the timing and extent of public participation. In addition, the commission will hear comment on the plan at a public hearing scheduled after the utility submits its plan for commission review.	Appendix A, Public Participation
RCW 19.280.030 (e) An assessment of methods, commercially available technologies, or facilities for integrating renewable resources, and addressing overgeneration events, if applicable to the utility's resource portfolio.	Chapter 8, Electric Analysis Appendix G, Electric Analysis Models Appendix H, Electric Analysis Inputs and Results

Figure B-3: Natural Gas Utility Integrated Resource Plan Regulatory Requirements Codified in WAC 480-90-238

Statutory or Regulatory Requirement	Chapter and/or Appendix
WAC 480-90-238 (3) (a) A range of forecasts of future natural gas demand in firm and interruptible markets for each customer class that examine the effect of economic forces on the consumption of natural gas and that address changes in the number, type and efficiency of natural gas end-uses.	Chapter 5, Key Analytical Assumptions Chapter 6, Demand Forecasts Appendix F, Demand Forecasting Models
WAC 480-90-238 (3) (b) An assessment of commercially available conservation, including load management, as well as an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.	Chapter 9, Natural Gas Analysis Appendix I, Natural Gas Analysis Results Appendix E, Conservation Potential Assessment and Demand Response Assessment
WAC 480-90-238 (3) (c) An assessment of conventional and commercially available nonconventional gas supplies.	Chapter 9, Natural Gas Analysis Appendix I, Natural Gas Analysis Results

Statistory or Regulatory Requirement	Chapter and/or Appendix
WAC 480-90-238 (3) (d) An assessment of opportunities for using company-owned or contracted storage.	Chapter 9, Natural Gas Analysis Appendix I, Natural Gas Analysis Results
WAC 480-90-238 (3) (e) An assessment of pipeline transmission capability and reliability and opportunities for additional pipeline transmission resources.	Chapter 9, Natural Gas Analysis Appendix I, Natural Gas Analysis Results
WAC 480-90-238 (3) (f) A comparative evaluation of the cost of natural gas purchasing strategies, storage options, delivery resources, and improvements in conservation using a consistent method to calculate cost-effectiveness.	Chapter 9, Natural Gas Analysis Appendix I, Natural Gas Analysis Results Appendix E, Conservation Potential Assessment and Demand Response Assessment
WAC 480-90-238 (3) (g) The integration of the demand forecasts and resource evaluations into a long-range (e.g., at least ten years; longer if appropriate to the life of the resources considered) integrated resource plan describing the mix of resources that is designated to meet current and future needs at the lowest reasonable cost to the utility and its ratepayers.	Chapter 3, Resource Plan Decisions
WAC 480-90-238 (3) (h) A short-term plan outlining the specific actions to be taken by the utility in implementing the long-range integrated resource plan during the two years following submission.	Chapter 1, Executive Summary
WAC 480-90-238 (3) (i) A report on the utility's progress towards implementing the recommendations contained in its previously filed plan.	Appendix B, Legal Requirements
WAC 480-90-238 (4) Timing. Unless otherwise ordered by the commission, each natural gas utility must submit a plan within two years after the date on which the previous plan was filed with the commission. Not later than twelve months prior to the due date of a plan, the utility must provide a work plan for informal commission review. The work plan must outline the content of the integrated resource plan to be developed by the utility and the method for assessing potential resources.	2021 Integrated Resource Plan Work Plan filed with the WUTC April, 2020, and Updated Work Plan filed May 15, 2020, July 8, 2020, September 17, 2020, October 26, 2020 and November 19, 2020.
WAC 480-90-238 (5) Public participation. Consultations with commission staff and public participation are essential to the development of an effective plan. The work plan must outline the timing and extent of public participation. In addition, the commission will hear comment on the plan at a public hearing scheduled after the utility submits its plan for commission review.	Appendix A, Public Participation

Figure B-4: Additional Condition Pursuant to WUTC Order 01 in Dockets UE-160918 and UG-160919

Statutory or Regulatory Requirement	Chapter and/or Appendix
Order 5-7 (5) For the 2019 IRP, PSE will hire a firm to do a survey of resource costs and recommend assumptions for use in the IRP. If reasonable, PSE will have the same consultants provide information for both fossil fuel plants and renewables. That study will include a detailed discussion of potential wind resources off the Washington coast, including areas that may be geographically limited for different reasons.	Appendix D, Electric Resources and Alternatives

Figure B-5: Natural Gas Utility Integrated Resource Plan HB 1257 Regulatory Requirements

Statutory or Regulatory Requirement	Chapter and/or Appendix
RCW 80.28.380 *Each gas company must identify and acquire all conservation measures that are available and cost-effective. Each company must establish an acquisition target every two years and must demonstrate that the target will result in the acquisition of all resources identified as available and cost-effective. The cost-effectiveness analysis required by this section must include the costs of greenhouse gas emissions established in RCW 80.28.395. The targets must be based on a conservation potential assessment prepared by an independent third party and approved by the commission. Conservation targets must be approved by order by the commission. The initial conservation target must take effect by 2022.*	Chapter 9, Natural Gas Analysis

Statutory or Regulatory Requirement	Chapter and/or Appendix
RCW 80.28.405 For the purposes of section 11 of this act, the cost of greenhouse gas emissions resulting from the use of natural gas, including the effect of emissions occurring in the gathering, transmission, and distribution of natural gas to the end user is equal to the cost per metric ton of carbon dioxide emissions, using the two and one-half percent discount rate, listed in table 2, Technical Support Document: Technical update of the social cost of carbon for regulatory impact analysis under Executive Order 12866, published by the interagency working group on social cost of greenhouse gases of the United States government, August 2016. The commission must adjust the costs established in this section to reflect the effect of inflation.	Chapter 5, Key Assumptions Chapter 9, Natural Gas Analysis

3. REPORT ON PREVIOUS ACTION PLANS

2017 Electric Action Plan

Per WAC 480-100-238 (3) (h), each item from the 2017 IRP electric resources action plan is listed below, along with the progress that has been made in implementing those recommendations.

Acquire Energy Efficiency

Develop two-year targets and implement programs that will put us on a path to achieve an additional 374 MW of energy efficiency by 2023 through program savings combined with savings from codes and standards.

PROGRESS: PSE collaborated with the Conservation Resource Advisory Group (CRAG) to develop the 2018-2019 total electric conservation program savings target of 59.41aMW and the 2020-21 program cycle savings target of 60.05 aMW.

Demand Response

Clarify the acquisition, prudence criteria and cost recovery process for demand response programs. Issue a demand response RFP based on those findings. Re-examine the peak capacity value of demand response programs in the 2019 IRP to include day-ahead demand response programs, and use the sub-hourly flexibility modeling capability developed in this IRP to value sub-hourly demand response programs.

PROGRESS: PSE is continuing to evaluate the best use cases for demand response (DR), including its potential as a non-wires alternative for transmission and distribution investments.

PSE filed a Demand Response RFP on May 4, 2020. The RFP called for demand response program offers to help meet capacity needs of 250 MW by 2026. The DR RFP solicited bids for both a system-wide electric demand response program, as well as smaller (3 to 5 MW, 3 to 5k MBH), geographically targeted electric and natural gas DR programs. Shortly before the WUTC was to rule on PSE's Draft All-Source and DR RFPs in mid-July 2020, PSE's updated load forecast indicated a significant reduction by 2026. Absent the originally forecasted capacity need in 2026, PSE petitioned for and was granted permission to withdraw both draft RFPs. The UTC granted the request on October 15, 2020, with the understanding that PSE will re-submit updated All-Source and

DR RFPs by April 1, 2021. More information about the RFPs, including the latest schedule updates, can be found online at www.pse.com/rfp.

Energy Storage

Install a small-scale flow battery to gain experience with the operation of this energy storage system in anticipation of greater reliance on flow batteries in the future.

PROGRESS: PSE installed a Primus EnergyPod flow battery at the Wild Horse Wind Facility's operations and maintenance building in April 2018. Technology and performance issues resulted in less than satisfactory operation, however, this test provided PSE with opportunities to learn about the challenges associated with flow battery technology. Ultimately, the flow battery was removed from the site after a year of trial and errors due to poor performance and leak issues. Once the battery was removed from the site, project documents were archived and communications with the vendor ceased.

Supply-side Resources: Issue an All-source RFP

Issue an all-source RFP in the first quarter of 2018 that includes updated resource needs and avoided cost information.

PROGRESS: PSE filed an All-resource RFP on June 8, 2018, which was subsequently approved by the WUTC on June 28, 2018. The RFP called for resources sufficient to meet PSE's need for additional capacity and renewable resources beginning in 2022 and 2023, respectively. To date, PSE has announced three resource acquisitions from the 2018 RFP: (1) a long-term power purchase agreement that will be supplied by Golden Hills, a 200 MW wind farm to be built by Avangrid Renewables in Sherman County, Ore.; (2) a five-year agreement with the Bonneville Power Administration for up to 100 MW of surplus power generated from the Federal Columbia River Power System; and (3) a long-term agreement to purchase the excess energy generated after wood waste is burned at Sierra Pacific Industries' cogeneration plant located at its Burlington lumber mill in Skagit County, Wash. More information about these resources can be found online at www.pse.com/rfp in the 2018 Demand Response and All-Source RFP Update section.

The RFP process is ongoing. PSE will update the website if and when new resources are contracted.

Develop Options to Mitigate Risk of Market Reliance

Develop strategies to mitigate the risk of redirecting transmission and increasing market reliance.

PROGRESS: In the 2017 IRP, PSE included a plan to redirect transmission from the Lower Snake River and Hopkins Ridge wind farms to Mid-C in the winter peak months. This would have provided for a low-cost alternative to increasing the amount of peak capacity associated with transmission at Mid-C. In the 2017-2018 winter months, PSE was unsuccessful in redirecting the amount of planned transmission from the wind farms to Mid-C due to constraints on BPA's affected flowgates. For this reason, this strategy was abandoned.

The idea of maintaining quick-build options has been abandoned. The "shelf life" of project permits is too short to justify the expense of obtaining them for a project that is merely an option. A more viable resource strategy is to rely upon shorter, three to five-year term deals from identified resources while longer term resources are selected and developed.

PSE continues to participate in wholesale energy markets in the western U.S., including the western states power pool, in order to make bilateral transactions to cover its energy and capacity needs. PSE has also joined markets for energy imbalance services and is involved in the extended day-ahead market initiative with others in the region.

Energy Imbalance Market (EIM)

Continue to participate in the California Energy Imbalance Market for the benefit of our customers.

PROGRESS: Participation has resulted in enhanced system reliability, more cost effective integration of variable energy resources, geographic diversity of electricity demand and generation resources, and cost savings for PSE customers. Benefits can take the form of cost savings or revenues or a combination of both. Benefits include transfer revenues, which are the net of payments received or paid by PSE for the transfer of energy between EIM participants; dispatch benefits, which are the difference between PSE's cost to dispatch resources to meet load on its own and PSE's cost to dispatch resources according to EIM instructions; greenhouse gas (GHG) revenues, which are payments from CAISO to offset California GHG cost obligations; and flexible ramping revenues, which are payments for transfer of flexible ramping capacity between EIM participants.

Regional Transmission

Examine regional transmission needs in the 2019 IRP in light of efforts to reduce the region's carbon footprint.

PROGRESS: Since 2019, PSE has taken steps to evaluate several regional transmission strategies that would help to address the future needs of CETA. These steps include:

- Analysis of PSE's existing portfolio of Bonneville Power Administration (BPA) transmission for opportunities to repurpose, redirect and/or share transmission with co-located resources.
- Expanded resource modeling in the 2021 IRP to consider regional transmission constraints.
- Participating in strategic discussions with BPA and other utilities in the Seattle area about expanding transmission across the Cascades.
- Evaluating investments in new regional transmission projects.
- Collaborating with NorthernGrid on the 2020-2021 regional study proposal.

Transmission updates are further discussed in Appendix J.

2017 Natural Gas Sales Action Plan

Acquire Energy Efficiency

Develop two-year targets and implement programs to acquire conservation, using the IRP as a starting point for goal-setting. This includes 14 MDth per day of capacity by 2022 through program savings and savings from codes and standards.

PROGRESS: PSE collaborated with the Conservation Resource Advisory Group (CRAG) to develop the 2018-2019 total gas conservation program savings target of 650 MDth and 2020-21 program cycle savings target of 795 MDth.

LNG Peaking Plant

Complete the PSE LNG peaking project located near Tacoma.

PROGRESS: Construction of the facility is nearing completion. PSE will begin plant commissioning and testing of the Tacoma LNG plant in January 2021, and normal operations will likely begin by March 2021.

Option to Upgrade Swarr

Maintain the ability upgrade the Swarr propane-air injection system in Renton, which the [2017 IRP] plan forecasts will be needed by the 2024/25 heating season.

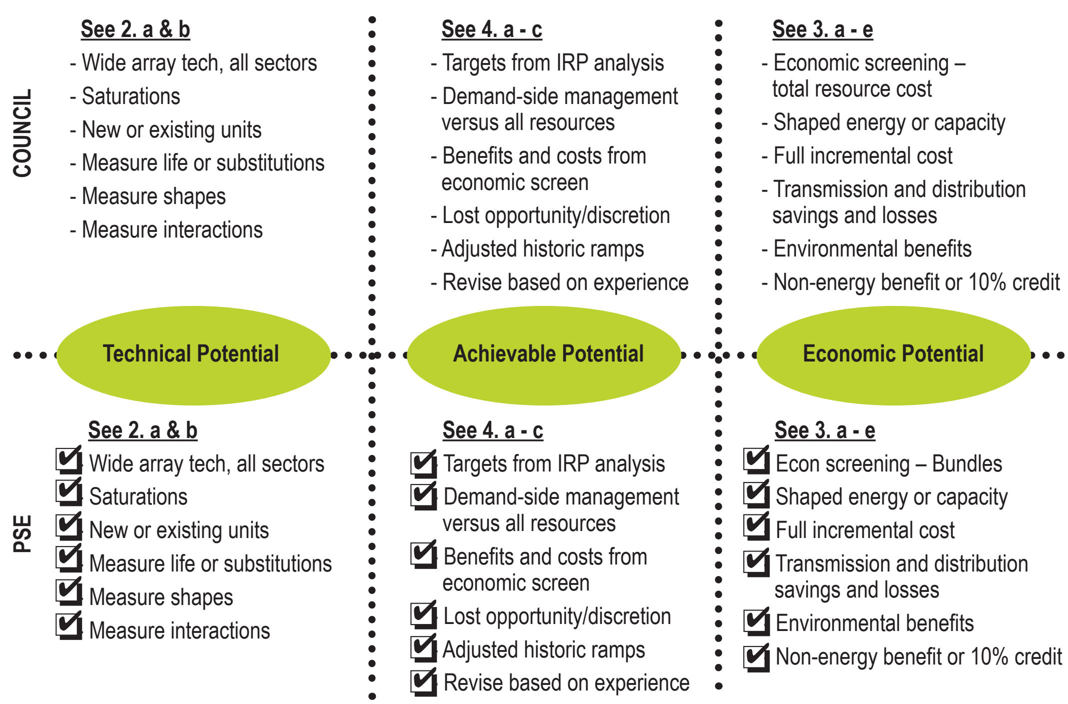
PROGRESS: The Swarr LP-Air facility is available for upgrade and the project can be upgraded on 2 years notice. Under the 2021 IRP Base Demand Forecast, the need for the upgrade is not currently forecasted to occur during the 2021 IRP study period.

4. OTHER REPORTS

Electric Demand-side Resource Assessment: Consistency with Northwest Power and Conservation Council Methodology

There are no legal requirements for the IRP to address the Northwest Power and Conservation Council (Council) methodology for assessing electric demand-side resources. Such comparison, however, may be useful for PSE and stakeholders in implementing sections of WAC 480-109. PSE has worked closely with Council staff on several aspects of our analytical process, including approaches to modeling demand-side resources. We are most grateful for the dialogue, and very much appreciate the opportunity to work with Council staff. WAC 480-109 does not define "methodology." PSE developed the detailed checklist below to demonstrate that our IRP process is consistent with the Council's methodology.[3]

Figure B-6: Comparison of Demand-side Resource Assessment Methodologies, PSE and the Northwest Power and Conservation Council



3 / *References in Figure B-4 refer to the Council's assessment of its methodology, found at:* *https://www.nwcouncil.org/media/112474/Methodology.pdf*

Department of Commerce
Integrated Resource Plan Cover Sheet

The WUTC is required to provide summary information about the IRPs of investor-owned utilities to the Department of Commerce. Information for the cover sheet is included in Figure B-7, below.

Figure B-7: Load-resource Balance Summary

Resource Plan Year:	2020
Base Year Start:	01/01/2020
Base Year End:	12/31/2020
Five-year Report Year:	2025
Ten-year Report Year:	2030

To be provided in the final 2021 IRP.

C Environmental Regulations

This appendix summarizes the environmental rules and regulations that apply to PSE energy production activities.

Contents

1. ENVIRONMENTAL PROTECTION AGENCY REGULATIONS

Air and Climate Change Protection

PSE owns several thermal generation facilities, including a number of natural gas plants and a percentage of the coal-fired Colstrip generating plant in Montana. All of these facilities are governed by the Clean Air Act (CAA), and all have CAA Title V operating permits, which must be renewed every five years. This renewal process could result in additional costs to the plants. PSE continues to monitor the permit renewal process to determine the corresponding potential impact to the plants.

These facilities also emit greenhouse gases (GHG), and thus are also subject to any current or future GHG or climate change legislation or regulation. The GHG regulations that apply to these facilities are described in detail in the section of this appendix titled "Greenhouse Gas Emissions."

Coal Combustion Residuals

On April 17, 2015, the United States Environmental Protection Agency (EPA) published a final rule, effective October 19, 2015, that regulates coal combustion residuals (CCRs) under the Resource Conservation and Recovery Act, Subtitle D. The CCR Rule supplies standards and criteria for the handling, storage and disposal of CCR. This includes regulations related to beneficial use, design, operation, closure, post-closure, groundwater monitoring and corrective action. The rule also sets out recordkeeping and reporting requirements, including posting specific information related to CCR surface impoundments and landfills to a publicly accessible website.

The CCR rule requires significant changes to PSE's Colstrip operations. Those changes were reviewed by PSE and the plant operator in the second quarter of 2015. PSE had previously recognized a legal obligation under the EPA rules to dispose of coal ash material at Colstrip in 2003. Due to the CCR rule, additional disposal costs were added to the Asset Retirement and Environmental Obligations (ARO), which is a closure and clean-up fund. In 2018, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) overturned certain provisions of the CCR rule in 2018 and remanded some of its provisions back to the EPA. As a result of that decision and certain other developments, on August 28, 2020, EPA published its final rule in the Federal Register (85 Fed. Reg. 53,516), entitled "Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities; A Holistic Approach to

Closure Part A: Deadline to Initiate Closure" (Part A Rule). The Part A Rule amends several regulatory provisions that govern coal combustion residuals and includes amendments that require certain CCR units (unlined or clay-lined surface impoundments and units failing the aquifer separation location restriction) to cease waste receipt and initiate closure "as soon as technically feasible" but no later than April 11, 2021. The final Part A Rule becomes effective on September 28, 2020.

Mercury and Air Toxics Standard (MATS)

The MATS rule established emissions limitations for hazardous air pollutants (HAPs) at coal-fired power plants, including limits for mercury of 1.2 lbs per trillion British thermal units (TBtu), and for acid gases and certain toxic heavy metals using a particulate matter surrogate of 0.03 lb per million British thermal units (MMBtu).

On February 7, 2019, the EPA published a proposal to reconsider the "appropriate and necessary" finding that underpins MATS, but to leave the MATS regulation in place (i.e., to keep regulating HAP emissions from power plants).[1] The proposal would not weaken any pollution standards immediately; however, it would create a higher threshold for future regulations by narrowing the range of benefits the agency can consider when determining whether it is "appropriate and necessary" to devise new rules under Section 112 of the Clean Air Act.

Mercury control equipment has been installed at Colstrip and has operated at a level that meets the current Montana requirement. Compliance, based on a rolling twelve-month average, was first confirmed in January 2011, and PSE continues to meet the requirement. Further, Colstrip met the Mercury and Air Toxics Standard (MATS) limits for mercury and acid gases as of April 2017.

1 / *84 FR 2670 (Feb. 7, 2019).*

Water Protection

PSE facilities that discharge wastewater or storm water or store bulk petroleum products are governed by the Clean Water Act (federal and state) which includes the Oil Pollution Act amendments. This includes most generation facilities (and all of those with water discharges and some with bulk fuel storage), and many other facilities and construction projects depending on drainage, facility or construction activities, and chemical, petroleum and material storage.

Regional Haze Rule (Montana)

Adopted in 1998, the Regional Haze program is a 64-year program administered by the EPA under federal law to improve visibility. Specifically, the rule is aimed at improving visibility in mandatory Class I areas (National Parks, National Forests and Wilderness Areas); it is not a health-based rule. The program requires periodic reviews of progress in improving visibility.

In January 2017, the EPA provided revisions to the Regional Haze Rule which were published in the Federal Register. Among other things, these revisions delayed new Regional Haze reviews from 2018 to 2021; however, the end date for these reviews will remain 2028. In January 2018, the EPA announced that it would revisit certain aspects of these revisions, and PSE is unable to predict the outcome. Challenges to the 2017 Regional Haze Revision Rule are pending in abeyance in the D.C. Circuit, pending resolution of EPA's reconsideration of the rule.

Greenhouse Gas Emissions

Section 111(b) of the Clean Air Act

On October 25, 2015, EPA published a final rule combining its proposals for new, modified and reconstructed power plants into one rulemaking – collectively, the greenhouse gas New Source Performance Standards (NSPS) – which made several changes to the original proposal. The final rule separated standards for new power plants fueled by natural gas and coal from existing plants. New and reconstructed natural gas power plants can emit no more than 1,000 lbs of CO_2 per MWh, which is based on the latest CCCT technology. EPA did not finalize a standard for modified gas plants. New coal power plants can emit no more than 1,400 lbs CO_2 per MWh, whereas reconstructed and modified coal plants have higher emission limits based on their heat input. Coal plants would not specifically be required to employ carbon capture and sequestration (CCS), but CCS was reaffirmed by EPA as the Best System of Emissions Reduction (BSER) (i.e., the basis for establishing the emission limit for these units). The 111(b) NSPS standards are implemented by the states.

On December 20, 2018, EPA published a proposed rule that would revise the GHG NSPS for coal-fired units based on the agency's revised determination that CCS is not the BSER for newly constructed coal-fired units. Instead, EPA proposed that the BSER for these units is either supercritical or subcritical steam conditions (depending on the unit's heat input) combined with best operating practices. EPA did not propose any changes to the NSPS for gas-fired power plants. EPA accepted public comments on the proposed GHG NSPS revisions through March 18, 2019. As of today, there have been no further actions on this rulemaking (see EPA Docket EPA-HQ-OAR-2013-0495).

EPA Clean Power Plan (CPP)

On October 23, 2015, EPA published the Clean Power Plan (CPP), which was the final rule under section 111(d) of the Clean Air Act to regulate GHG emissions from existing power plants. The final rule included several changes from the proposed rule. Specifically, the EPA excluded energy efficiency from the "building blocks" states could use to meet the standard, leaving just three building blocks:

- increased efficiency for coal plants,
- greater utilization of natural gas plants, and
- increased renewable sources.

Soon after the EPA published the CPP, 27 states, along with several utilities, electric cooperatives and industry groups, challenged the rule's legality in the D.C. Circuit. On February 8, 2016, the U.S. Supreme Court stayed the effectiveness of the CPP pending the disposition of the challenges in the D.C. Circuit. On April 28, 2017, the D.C. Circuit granted EPA's request to put the lawsuits challenging the CPP on hold indefinitely without deciding the case (i.e., place the litigation in abeyance). That decision followed a request to halt the case from EPA, which was in the process of proposing to repeal and replace the CPP.

On October 16, 2017, EPA published a proposal to repeal the CPP based on a revised interpretation of section 111(d) of the Clean Air Act that requires emission standards to be based on pollution-control measures that can be applied to or at an existing source. This proposed interpretation of section 111(d) would mean that the CPP exceeds EPA's authority under the Clean Air Act by including the second and third building blocks: switching from coal to gas-powered generation and increasing generation from renewable sources. Because the CPP stated that the first building block (efficiency measures at coal plants) could not legally stand on its own if the other two blocks were repealed, EPA proposed that the entire CPP had to be repealed.

On August 31, 2018 the EPA published a replacement for the CPP, called the Affordable Clean Energy (ACE) Rule. The ACE Rule proposed to require modest efficiency improvements at some coal plants and give states more latitude to set their own carbon emission reduction standards, in contrast to the CPP, which pushed plant owners to invest in less-polluting sources. The ACE Rule also proposed changes to the test for whether physical or operational changes would trigger permitting requirements for a source under the New Source Review Program (NSR). The NSR revisions were proposed in light of the fact that some of the efficiency improvements required to comply with the GHG emission standard might trigger these permitting requirements under current law.

On July 8, 2019, EPA published the final ACE Rule, which repealed the CPP and replaced it with the more modest program that EPA had proposed; however, the final ACE Rule did not include the proposed changes to the NSR program. EPA plans to finalize those changes in a separate rulemaking at a later date. The CPP-replacement portion of the ACE Rule is structured similarly to EPA's proposal, except that it contains slightly less flexibility for states to decide how to regulate their sources than what was proposed. These limitations include a prohibition on using emissions averaging or trading as a mechanism for complying with standards of performance. Compliance is generally required by July 2024. PSE is evaluating the final ACE rule to determine its impact on operations.

2. STATE AND REGIONAL REGULATIONS

California Cap-and-trade Program

On December 16, 2010, the California Air Resources Board (CARB) adopted final rules to enact cap-and-trade provisions in accordance with California's Global Warming Solutions Act of 2006 (AB 32). The final rule defines the ground rules for participating in the cap-and-trade program, including enforcement and linkage to outside programs. The compliance obligations became binding on January 1, 2013.

AB 32 requires California to reduce greenhouse gas (GHG) emissions to 1990 levels by 2020. It directs power providers to account for emissions from in-state generation and imported electricity. The regulatory approach assigns the electricity importer as the "first deliverer" of imported electricity and thus the point of regulation. Cap-and-trade regulations distinguish between "specified" and "unspecified" sources of electricity. An unspecified source means electricity generation that cannot be matched to a particular generating facility; these sources are subject to the default emission factor of 0.428 metric tons (MT) of carbon dioxide equivalents (CO_2e) per MWh. A specified source is a particular generating unit or facility for which electrical generation can be confidently tracked due to full or partial ownership or due to its identification in a power contract, including any California-eligible renewable resource or an asset-owning or asset-controlling supplier. Imports from specified sources are eligible for a source-specific emission factor. To be eligible for a source-specific emission factor, imported electricity must not only come from a specified source, but any renewable energy credits associated with the electricity must be retired and verified. Imported electricity can be assigned an emission factor lower than the default emission factor only if the electricity is directly delivered, meaning the facility has a first point of interconnection with a California balancing authority or the electricity is scheduled for delivery from the specified source into a California balancing authority via a continuous transmission path.

On July 25, 2017, the California Governor signed into law AB 398, extending through 2030 the cap-and-trade program authorized by AB 32. The new law requires CARB to develop a Scoping Plan which includes price ceilings and price containment points to further reduce California's emissions to 40 percent below 1990 levels by 2030. The law does not prescribe specific measures, except for approving the use of revenues from allowance auctions for investment in clean technologies.

CARB's Scoping Plan was released in December 2017 and called for cap-and-trade to be the backstop policy that drives complementary programs; these include zero emission vehicle regulations, the low carbon fuel standard and the state's mandate for 50 percent renewable electricity by 2030.[2]

Washington State

Washington Clean Energy Transformation Act

In May 2019, Washington State passed the 100 Percent Clean Electric Bill that supports Washington's clean energy economy and transition to a clean, affordable and reliable energy future. The Clean Energy Transformation Act requires all electric utilities to eliminate coal-fired generation from their allocation of electricity by December 31, 2025 and to be carbon neutral by January 1, 2030 through a combination of non-emitting electric generation, renewable generation, and/or alternative compliance options. It also makes it state policy that, by 2045, 100 percent of electric generation and retail electricity sales will come from renewable or non-emitting resources. Clean Energy Implementation plans are required every four years from each investor-owned utility (IOU). These implementation plans must propose interim targets for meeting the 2045 standard between 2030 and 2045 and lay out an actionable plan that the IOU intends to pursue to meet the standard. The Washington Utilities and Transportation Commission (WUTC) may approve, reject or recommend alterations to an IOU's plan.

In order to meet these requirements, the Act clarifies the WUTC's authority to consider and implement performance- and incentive-based regulation, multi-year rate plans and other flexible regulatory mechanisms where appropriate. The Act mandates that the WUTC accelerate depreciation schedules for coal-fired resources, including transmission lines, to December 31, 2025, or to allow IOUs to recover costs in rates for earlier closure of those facilities. IOUs will be allowed to earn a rate of return on certain Power Purchase Agreements (PPAs) and 36 months deferred accounting treatment for clean energy projects (including PPAs) identified in the utility's clean energy implementation plan.

IOUs are considered to be in compliance when the cost of meeting the standard or an interim target within the four-year period between plans equals a 2 percent increase in the weather-adjusted sales revenue to customers from the previous year. If relying on the cost cap exemption, IOUs must demonstrate that they have maximized investments in renewable resources and non-emitting generation prior to using alternative compliance measures.

2 / Note that since CARB released its scoping plan, the mandate has since been increased to 60 percent renewables by 2030 and 100 percent renewables by 2045. See California Renewable Portfolio Standard, infra, describing California's SB 100.

The law requires additional rulemaking by several Washington agencies for its measures to be enacted, and PSE is unable to predict the outcomes of the rulemakings at this time. PSE intends to seek recovery of any costs associated with the clean energy legislation through the regulatory process.

Greenhouse Gas Emissions Performance Standard

Washington state law RCW 80.80.060(4), the GHG Emissions Performance Standard (EPS), establishes a limit for CO_2 emissions per MWh from new baseload generating resources, and it prohibits utilities from entering into long-term contracts of five years or more to acquire power from existing generating resources that exceed this standard. Contracts of less than five years are allowed.

This means that PSE is prohibited from building or purchasing baseload generation resources that exceed the emission performance standard. Investor-owned utilities like PSE may apply to the WUTC for exemptions based on certain reliability and cost criteria.

The law was amended in 2011. This amendment incorporated changes related to the negotiated shutdown of the TransAlta coal-fired power plant located near Centralia, Wash. The change allows TransAlta to enter into “coal transition power” contracts with Washington utilities. It exempts TransAlta and the coal transition power contracts from complying with the EPS until the dates the coal units are required to meet the EPS in 2020 (for Unit 1) and 2025 (for Unit 2).

The current EPS, set in 2018, is 925 lbs of CO_2 emissions per MWh, and the EPS is reviewed every five years.

Carbon Dioxide Mitigation Program

In 2004, the Washington State legislature passed Substitute House Bill 3141, later codified in RCW 80.70. The law requires new or modified fossil-fueled thermal power plants above 25 megawatts (net output of the electric generator) to provide mitigation for 20 percent of the CO_2 emissions it produces over a 30-year period. The mitigation requirement applies to all new power plants filing for a Site Certification Agreement or Notice of Construction after July 1, 2004. The mitigation requirement also applies to modifications of existing plants permitted by Washington’s Department of Ecology or a local air quality agency that will increase power production capacity by 25 MW or more, or increase CO_2 emissions by 15 percent or more. If mitigation is triggered, compliance must be attained through any one or a combination of these methods:

1. paying an “Independent Qualified Organization” to verify compliance,
2. purchasing permanent, verifiable carbon credits, or
3. using a self-directed mitigation program.

If the third option is chosen, the mitigation program must be identified within a plan submitted as part of the permit application. Payment to a qualified organization and the cost for a self-directed mitigation program are initially limited to an amount derived by multiplying the tons of CO_2 emissions to be mitigated by $1.60.

Washington Clean Air Rule (CAR)

Washington State adopted the CAR in September 2016, which attempts to reduce greenhouse gas emissions from “covered entities” located within Washington state. Included under the new rule are large manufacturers, petroleum producers and natural gas utilities, including PSE. The CAR sets a cap on emissions associated with covered entities which decreases over time, approximately 5.0 percent every three years. Entities must reduce their carbon emissions or purchase emission reduction units (ERUs), as defined under the rule, from others.

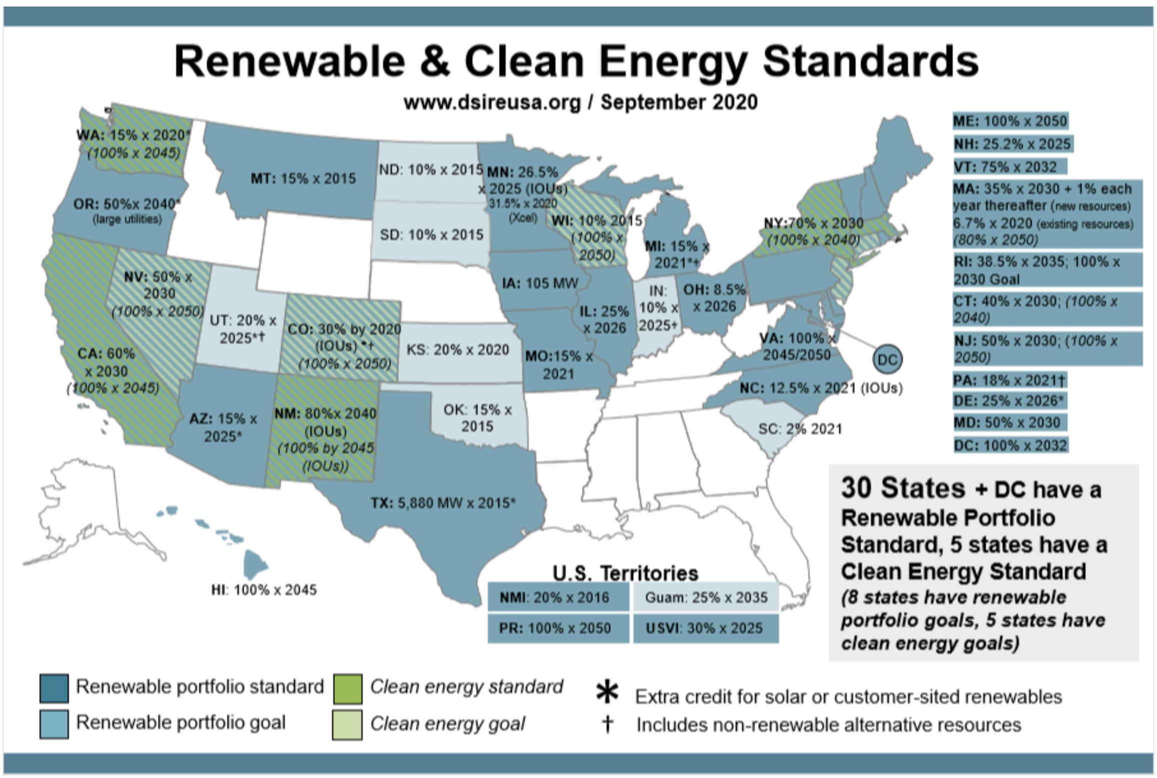
In September 2016, PSE, along with Avista Corporation, Cascade Natural Gas Corporation and NW Natural, filed a lawsuit in the U.S. District Court for the Eastern District of Washington challenging the CAR. In September 2016, the four companies filed a similar challenge to the CAR in Thurston County Superior Court. In March 2018, the Thurston County Superior Court invalidated the CAR. The Department of Ecology appealed the Superior Court decision in May 2018. As a result of the appeal, direct review to the Washington State Supreme Court was granted and oral argument was held on March 16, 2019. In January 2020, the Washington Supreme Court affirmed that CAR is not valid for “indirect emitters” meaning it does not apply to the sale of natural gas for use by customers. The court ruled, however, that the rule can be severed and is valid for direct emitters including electric utilities with permitted air emission sources, but remanded the case back to the Thurston County to determine which parts of the rule survive. Meanwhile, the federal court litigation has been held in abeyance pending resolution of the state case.

Renewable Portfolio Standards (RPS)

Renewable portfolio standards require utilities to obtain a specific portion of their electricity from renewable energy resources. Of the 11 interconnected Western states, eight have binding renewable energy targets, one has a voluntary goal, and two have no RPS in place. PSE has met Washington’s RPS requirement to meet 3 percent of load with renewable resources for target years 2012-2015, 9 percent for 2016-2019 and 15 percent starting in 2020. RPS provisions vary widely among the different jurisdictions in the absence of a federal mandate. Differences include the specific portion of renewable resources required, the timeline to meet the requirements, the types of resources that qualify as renewable, the geographic location from which renewable resources can be sourced, eligible commercial on-line dates and any applicable technology carve-outs (such as solar). The result is a patchwork of regulatory mandates, evolving regulations and segregated environmental markets. Managing these moving parts is complex from both a resource acquisition perspective and an environmental markets perspective.

PSE must actively monitor RPS requirements throughout the Western region, because the interconnectedness of the grid and regional energy markets means that changes in one state can have a pronounced impact on the entire system. In particular, PSE pays close attention to requirements in Oregon, California and Idaho (which currently has no RPS). Figure C-1, below, illustrates the wide variety of RPS requirements that exist. The table in Figure C-2 lists the current RPS requirements for each state within the Western Interconnect.[3]

Figure C-1: RPS Requirements by State



3 / Per Figure C-2, State RPS and Eligible Technologies are drawn from the Western Interstate Energy Board's publication Exploring and Evaluating Modular Approaches to Multi-State Compliance with EPA's Clean Power Plan in the West, April 29, 2015, with updated RPS requirements from DSIRE.

Figure C-2: RPS Requirements for States in the Western Interconnect

STATE	RPS	ELIGIBLE RENEWABLE ENERGY
Arizona	15% by 2025	Solar water heat, solar space heat, solar thermal electric, solar thermal process heat, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, geothermal heat pumps, combined heat and power (CHP)/cogeneration (CHP only counts when the source fuel is an eligible RE resource), solar pool heating (commercial only), daylighting (non-residential only), solar space cooling, solar HVAC, anaerobic digester, small hydroelectric, fuel cells using renewable fuels, geothermal direct-use, additional technologies upon approval
California	60% by 2030 100% by 2045	Solar thermal electric, photovoltaics, landfill gas, wind, biomass, geothermal electric, municipal solid waste, energy storage, anaerobic digestion, small hydroelectric, tidal energy, wave energy, ocean thermal, biodiesel, and fuel cells using renewable fuels
Colorado	30% by 2020 (IOUs); Co-ops serving >100,000 meters: 20% by 2020; Co-ops serving <100,000 meters: 10% by 2020; Municipal utilities serving >40,000 customers: 10% by 2020 100% by 2050	Solar thermal electric, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, recycled energy, coal mine methane (if the Colorado Public Utilities Commission determines it is a GHG-neutral technology), pyrolysis of municipal solid waste (if the Commission determines it is a GHG-neutral technology), anaerobic digester, and fuel cells using renewable fuels
Idaho	None	N/A
Montana	15% by 2015	Solar thermal electric, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, compressed air energy storage, battery storage, flywheel storage, pumped hydro (from eligible renewables), anaerobic digester, and fuel cells using renewable fuels
New Mexico	80% by 2040 (IOUs) 100% by 2045 (IOUs)	Solar thermal electric, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, zero emission technology with substantial long-term production potential, anaerobic digester, and fuel cells using renewable fuels
Nevada	50% by 2030 and thereafter Goal: 100% by 2050	Solar water heat, solar space heat, solar thermal electric, solar thermal process heat, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, municipal solid waste, waste tires (using microwave reduction), energy recovery processes, solar pool heating, anaerobic digestion, biodiesel, and geothermal direct use
Oregon	50% by 2040 (large IOUs); 5-25% by 2025 (other utilities)	Solar thermal electric, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, municipal solid waste, hydrogen, anaerobic digestion, tidal energy, wave energy, and ocean thermal
Utah	No requirement Goal of 20% by 2025	Solar water heat, solar space heat, geothermal electric, solar thermal electric, solar photovoltaics, wind (all), biomass, hydroelectric, hydrogen, municipal solid waste, combined heat & power, landfill gas, tidal, wave, ocean thermal, wind (small), hydroelectric (small), anaerobic digestion
Washington	RPS: 15% by 2020 and all cost-effective conservation CETA: 80% by 2030 and 100% by 2045	Solar thermal electric, photovoltaics, landfill gas, wind, bio-mass, incremental and low-head hydroelectric, geothermal electric, anaerobic digestion, tidal energy, wave energy, ocean thermal, and biodiesel
Wyoming	None	N/A

NOTE: Approved technologies are generated in the state (excluding hydro generation). In many cases, generation in one state is used for RPS compliance in a different state.

California Renewable Portfolio Standard

California has one of the most aggressive RPS mandates in the region. The size and aggressiveness of its mandate make it the region's primary driver of renewable resource availability and cost, REC product availability and cost, and transmission and integration.

The state's program was originally established in 2002, and its goals have been extended and accelerated several times since then.

- When Senate Bill SB X 1-2 was signed into law in April 2011, the renewable energy goal was increased from 20 percent to 33 percent of retail sales by 2020. This applies to all California investor-owned utilities, electric service providers (ESPs), community choice aggregators (CCAs) and publicly owned utilities.

- When Senate Bill 350 was signed into law in 2015, the renewable requirement for retail sellers and publicly owned utilities was increased to 50 percent by 2030.

- When Senate Bill 100 was signed into law in 2018, California committed to phasing out all fossil fuels from the state's electricity sector by 2045. This goal requires renewable energy and zero-carbon resources to supply 100 percent of electric sales to end-use customers by 2045.

Under Senate Bill SB X 1-2, the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) were tasked with implementing the expanded RPS. In December 2011, the CPUC issued a decision that addressed the criteria for inclusion in each of the new RPS portfolio content categories and the percentage of the annual procurement target that could be sourced from unbundled RECs. The use of unbundled renewable energy credits was capped at 25 percent of a utility's RPS requirement through December 31, 2013; this steps down to 15 percent in 2014 and 10 percent in 2017. The decision applies to contracts and ownership agreements entered into after June 1, 2010.

D Electrical Resources and Alternatives

This appendix describes PSE's existing electric resources; current electric resource alternatives and the viability and availability of each; and estimated ranges for capital and operating costs. [1]

1 / *Operating costs are defined as operation and maintenance costs, insurance and property taxes. Capital costs are defined as depreciation and carrying costs on capital expenditures.*

Contents

1. RESOURCE TYPES

The following overview summarizes some of the distinctions used to classify electric resources.

Supply-side and Demand-side

Both of these types of resources are capable of enabling PSE to meet customer loads. Supply-side resources provide electricity to meet load, and these resources originate on the utility side of the meter. Demand-side resources contribute to meeting need by reducing demand. An "integrated" resource plan includes both supply- and demand-side resources.

SUPPLY-SIDE RESOURCES for PSE include:

- Generating plants, including combustion turbines (baseload and peakers), coal, hydro and wind plants
- Long-term contracts with independent producers to supply electricity to PSE (these have a variety of fuel sources)
- Transmission contracts with Bonneville Power Administration (BPA) to carry electricity from short-term wholesale market purchases to PSE's service territory

DEMAND-SIDE RESOURCES for PSE include:

- Energy efficiency
- Distribution efficiency
- Generation efficiency
- Distributed generation
- Demand response

The contribution that demand-side programs make to meeting resource need is accounted for as a reduction in demand for the IRP analysis.

Thermal and Renewable

These supply-side resources are distinguished by the type of fuel they use.

THERMAL RESOURCES use fossil fuel (natural gas, oil, coal) or other fuels (biodiesel, hydrogen, renewable natural gas) to generate electricity. PSE's combustion turbines and coal-fired generating facilities are thermal resources.

RENEWABLE RESOURCES use renewable fuels such as water, wind, sunlight and biomass to generate electricity. Hydroelectricity and wind generation are PSE's primary renewable resources.

Baseload, Peaking, Intermittent and Storage

These distinctions refer to how the resource functions within the system.

BASELOAD RESOURCES produce energy at a constant rate over long periods at a lower cost relative to other production facilities available to the system. They are typically used to meet some or all of a region's continuous energy demand. Baseload resources usually have a high fixed cost but low marginal cost and thus could be characterized as the most efficient units of the fleet.

For PSE, baseload resources can be divided into two categories: thermal and hydro. These have different dispatching capabilities. Thermal baseload plants can take up to several hours to start and have limited ability to ramp up and down quickly, so they are not very flexible. Hydro plants, on the other hand, are very flexible and are typically the preferred resource to balance the system.

PSE's three sources of baseload energy are combined-cycle combustion turbines (CCCTs), hydroelectric generation and coal-fired generation.

PEAKING RESOURCES are quick-starting units that can ramp up and down quickly in order to meet short-term spikes in need. They also provide flexibility needed for load following, wind integration and spinning reserves. Peaking resources generally have a lower fixed cost but are less efficient than baseload plants. Historically, peaking units have low capacity factors because they are often not economical to operate compared to market purchases.

The flexibility of peaking resources will become more important in the future as new renewable resources are added to the system and as PSE continues to participate in the Energy Imbalance Market.

PSE's peaking resources include simple-cycle combustion turbines (SCCTs) and hydroelectric plants that can perform peaking functions in addition to baseload functions.

INTERMITTENT RESOURCES, also commonly referred to as Variable Energy Resources (VERs), provide power that offers limited discretion in the timing of delivery. Renewable resources like wind and solar are intermittent resources because their generating patterns vary as a result of uncontrollable environmental factors, so the timing of delivery from these resources doesn't necessarily align with customer demand. As a result, additional resources are required to back up intermittent resources in case the wind dies down or clouds cover the sun.

PSE's largest intermittent resources are utility-scale wind generation and solar generation. Other intermittent resources include small-scale power production from customer generation (including rooftop solar), and the 10 aMW of energy PSE is required to take from co-generation.

For planning purposes, PSE includes the randomness, forced outage rates and curtailments of each particular type of technology in its analysis.

ENERGY STORAGE has the potential to provide multiple services to the system, including efficiency, reliability, capacity arbitrage, ancillary services and backup power for intermittent renewable generation. It is capable of benefiting all parts of the system – generation, transmission, distribution and end-use customers; however, these benefits vary by location and the specific application of the technology or resource. For instance, storage in one location could be installed to relieve transmission congestion and thereby defer the cost of transmission upgrades, while storage at another location might be used to back up intermittent wind generation and reduce integration costs.

PSE's energy storage resources include hydro reservoirs behind dams, oil backup for the peaking plants and batteries. Battery and pumped hydro energy storage operate with a limited duration and require generation from other sources. Detailed modeling is required to fully evaluate the value of energy storage at the sub-hourly level.

Capacity Values

The tables on the following pages describe PSE's existing electric resources using the net maximum capacity of each plant in megawatts (MW). Net maximum capacity is the capacity a unit can sustain over a specified period of time – in this case 60 minutes – when not restricted by ambient conditions or de-ratings, less the losses associated with auxiliary loads and before the losses incurred in transmitting energy over transmission and distribution lines. This is consistent with the way plant capacities are described in the annual 10K report[2] that PSE files with the U.S. Securities and Exchange Commission and the Form 1 report filed with the Federal Energy Regulatory Commission (FERC).

Different plant capacity values are referenced in other PSE publications because plant output varies depending upon a variety of factors, among them ambient temperature, fuel supply, whether a natural gas plant is using duct firing, whether a combined-cycle facility is delivering steam to a steam host, outages, upgrades and expansions. To describe the relative size of resources, it is necessary to select a single reference point based on a consistent set of assumptions. Depending on the nature and timing of the discussion, these assumptions – and therefore the expected capacity value – may vary.

2 / PSE's most recent 10K report was filed with the U.S. Securities and Exchange Commission in February 2020 for the year ending December 31, 2019. See http://www.pugetenergy.com/pages/filings.html.

2. EXISTING RESOURCES INVENTORY

Supply-side Thermal Resources

Baseload Combustion Turbines (CCCTs)

PSE’s six baseload combined-cycle combustion turbine plants have a combined net maximum capacity of 1,293 MW and supply 15 to 16 percent of PSE’s baseload energy needs, depending on market heat rates and plant availabilities. In a CCCT, the heat that a simple-cycle combustion turbine produces when it generates power is captured and used to create additional energy. This makes it a more efficient means of generating power than the peakers (simple-cycle turbines) described below. PSE's fleet of baseload CCCTs includes the following.

MINT FARM is located in Cowlitz County, Wash.

FREDERICKSON 1 is located in Pierce County, Wash. (PSE owns 49.85 percent of this plant; the remainder of the plant is owned by Atlantic Power Corporation.)

GOLDENDALE is located in Klickitat County, Wash.

ENCOGEN, FERNDALE and **SUMAS** are located in Whatcom County, Wash.

Coal

The Colstrip generating plant currently supplies 16 to 17 percent of PSE’s baseload energy needs.

THE COLSTRIP GENERATING PLANT. Located in eastern Montana about 120 miles southeast of Billings, the plant consists of four coal-fired steam electric plant units. PSE owns 25 percent each of Units 3 & 4. PSE’s total ownership in Colstrip contributes 370 MW net maximum capacity to the existing portfolio.

The Colstrip Generating Plant Retirement/Shutdown Plan. After a request in June 2019 by PSE’s Unit 1 & 2 co-owner and plant operator, Talen Montana LLC, PSE agreed to retire the units. The decision was based on economic considerations. In early January 2020, the facility ceased to generate electricity and work commenced to place it in a secure and safe condition. Environmental remediation of impacted water is currently under way and will continue, in compliance with all local, state and federal regulations, as the retirement of the physical structures occurs. In the future, when Units 3 & 4 have also been retired, the main structures of Units 1 & 2 will be further addressed.

Units 3 & 4 are owned by six separate entities with different interests. PSE is limited in its ability to act unilaterally since operational decisions are dictated by the rules governing the ownership agreement. The Clean Energy Transformation Act (CETA) restricts PSE from serving load from Colstrip without penalty after 2025. The status of PSE's interest in Colstrip after 2025 is unknown.

Figure D-1: PSE's Owned Baseload Thermal Resources

POWER TYPE	UNITS	PSE OWNERSHIP	NET MAXIMUM CAPACITY (MW)[1]
Coal	Colstrip 3 & 4[1]	25%	370
Total Coal			**370**
CCCT	Encogen	100%	165
CCCT	Ferndale[2]	100%	253
CCCT	Frederickson 1[2,3]	49.85%	136
CCCT	Goldendale[2]	100%	315
CCCT	Mint Farm[2]	100%	297
CCCT	Sumas	100%	127
Total CCCT			**1,293**

NOTES
1. Net maximum capacity reflects PSE's share only.
2. Maximum capacity of Ferndale, Frederickson 1, Goldendale and Mint Farm includes duct firing capacity.
3. Frederickson 1 CCCT unit is co-owned with Atlantic Power Corporation - USA.

Peakers (SCCTs)

These simple-cycle combustion turbines provide important peaking capability and help PSE meet operating reserve requirements. The company displaces these resources when their energy is not needed to serve load or when lower-cost energy is available for purchase. PSE's three peaker plants (eight units total) contribute a net maximum capacity of 612 MW. When pipeline capacity is not available to supply them with natural gas fuel, these units are capable of operating on distillate fuel oil.

FREDONIA Units 1, 2, 3 and 4 are located near Mount Vernon, Wash., in Skagit County.

WHITEHORN Units 2 and 3 are located in northwestern Whatcom County, Wash.

FREDERICKSON Units 1 and 2 are located south of Seattle in east Pierce County, Wash.

Ownership and net maximum capacity are shown in Figure D-2 below.

Figure D-2: PSE's Owned Peaking Resources (Simple-cycle Combustion Turbines)

NAME	PSE OWNERSHIP	NET MAXIMUM CAPACITY (MW)
Fredonia 1 & 2	100%	207
Fredonia 3 & 4	100%	107
Whitehorn 2 & 3	100%	149
Frederickson 1 & 2	100%	149
Total SCCT		**612**

Supply-side Renewable Resources

Hydroelectricity

Hydroelectricity supplies approximately 14 percent of PSE's baseload energy needs. Even though restrictions to protect endangered species limit the operational flexibility of hydroelectric resources, these generating assets are valuable because of their ability to instantly follow customer load and because of their low cost relative to other power resources. High precipitation and snowpack levels generally allow more power to be generated, while low-water years produce less power. During low-water years, the utility must rely on other, more expensive, self-generated power or market resources to meet load. The analysis conducted for this IRP accounts for both seasonality and year-to-year variations in hydroelectric generation. PSE owns hydroelectric projects in western Washington and has long-term power purchase contracts with three public utility districts (PUDs) that own and operate large dams on the Columbia River in central Washington. In addition, we contract with smaller hydroelectric generators located within PSE's service territory.

BAKER RIVER HYDROELECTRIC PROJECT. This facility is located in Washington's north Cascade Mountains. It consists of two dams and is the largest of PSE's hydroelectric power facilities. The project contains modern fish-enhancement systems including a "floating surface collector" (FSC) to safely capture juvenile salmon in Baker Lake for downstream transport around both dams, and a second, newer FSC on Lake Shannon for moving young salmon around Lower Baker Dam. In addition to generating electricity, the project provides public access for recreation and significant flood-control storage for people and property in the Skagit Valley. Hydroelectric projects require a license from FERC for construction and operation. These licenses normally are for periods of 30 to 50 years; then they must be renewed to continue operations. In October 2008, after a lengthy renewal process, FERC issued a 50-year license allowing PSE to generate approximately 710,000 MWh per year (average annual output) from the Baker River project. PSE also completed construction of a new powerhouse and 30 MW generating unit at Lower Baker dam in July 2013. The replacement unit improves river flows for fish downstream of the dam while producing more than 100,000 additional MWh of energy from the facility each year. This incremental energy qualifies as a renewable resource under the State of Washington Energy Independence Act, RCW 19.285.

SNOQUALMIE FALLS HYDROELECTRIC PROJECT. Located east of Seattle on the Cascade Mountains' western slope, the Snoqualmie Falls Hydroelectric Project consists of a small diversion dam just upstream from Snoqualmie Falls and two powerhouses. The first powerhouse, which is encased in bedrock 270 feet beneath the surface, was the world's first completely underground power plant. Built in 1898-99, it was also the Northwest's first large hydroelectric power plant. FERC issued PSE a 40-year license for the Snoqualmie Falls Hydroelectric Project in 2004. The terms and conditions of the license allow PSE to generate an estimated 275,000 MWh per year (average annual output). The facility underwent a major redevelopment project between 2010 and 2015, which included substantial upgrades and enhancements to the power-generating infrastructure and public recreational facilities. Efficiency improvements completed as part of the redevelopment increase annual output by over 22,000 MWh. This incremental energy qualifies as a renewable resource under the State of Washington Energy Independence Act, RCW 19.285.

MID-COLUMBIA LONG-TERM PURCHASED POWER CONTRACTS. Under long-term power purchase agreements with three PUDs, PSE purchases a percentage of the output of five hydroelectric projects located on the Columbia River in central Washington. PSE pays the PUDs a proportionate share of the cost of operating these hydroelectric projects. In March 2017, PSE entered into a new power sales agreement with Douglas County PUD that began on August 31, 2018 and continues through September 30, 2028. Under this new agreement PSE will continue to take a percentage of the output from the Wells project. The actual percentage available to PSE will be calculated annually and based primarily on Douglas PUD's retail load requirements – as Douglas PUD's retail load grows (or declines), they will reserve a greater (or lesser) share of Wells project output for their customers and the percentage PSE purchases will decline (or increase) as a result. PSE has a 20-year agreement with Chelan County PUD for the purchase of 25 percent of the output of the Rocky Reach and Rock Island projects that extends through October 2031. PSE has an agreement with Grant County PUD for a 0.64 percent share of the combined output of the Wanapum and Priest Rapids developments. The agreement with Grant County PUD will continue through the term of the project's FERC license, which ends March 31, 2052.

Figure D-3: PSE Owned and Contracted Hydroelectric Resources

PLANT	OWNER	PSE SHARE %	NET MAXIMUM CAPACITY (MW)[1]	CONTRACT EXPIRATION DATE
Upper Baker River	PSE	100	91	None
Lower Baker River	PSE	100	105	None
Snoqualmie Falls	PSE	100	48[2]	None
Total PSE-owned			**244**	
Wells	Douglas Co. PUD	30.2	228[3]	9/30/28[3]
Rocky Reach	Chelan Co. PUD	25.0	325	10/31/31
Rock Island I & II	Chelan Co. PUD	25.0	156	10/31/31
Wanapum	Grant Co. PUD	0.6	7	03/31/52
Priest Rapids	Grant Co. PUD	0.6	6	03/31/52
Contracted Total			**706**	
Total Hydro			**950**	

NOTES
1. Net maximum capacity reflects PSE's share only.
2. The FERC license authorizes the full 54.4 MW; however, the project's water right, issued by the state Department of Ecology, limits flow to 2,500 cfs, and therefore output, to 47.7 MW.
3. In March 2017, PSE entered a new PPA with Douglas County PUD for Wells Project output that began on August 31, 2018 and continues through September 30, 2028. PSE also entered into an agreement in June 2018 to purchase an additional 5.5 percent of the Wells project through September 2021.

Wind Energy

PSE is the largest utility owner and operator of wind-power facilities in the Pacific Northwest. Combined, the maximum capacity of the company's three wind farms is 773 MW. They are forecast to produce more than 2 million MWhs of power per year on average, which is about 8 percent of PSE's energy needs. These resources are integral to meeting renewable resource commitments.

HOPKINS RIDGE. Located in Columbia County, Wash., Hopkins Ridge has an approximate maximum capacity of 157 MW. It began commercial operation in November 2005.

WILD HORSE. Located in Kittitas County near Ellensburg, Wash., Wild Horse has an approximate maximum capacity of 273 MW. It came online in December 2006 at 229 MW and was expanded by 44 MW in 2010.

LOWER SNAKE RIVER. PSE brought online its third and largest wind farm in February 2012. The 343 MW facility is located in Garfield County, Wash.

Solar Energy

The Wild Horse facility contains 2,723 photovoltaic solar panels, including the first made-in-Washington solar panels.[3] The array can produce up to 0.5 MW of electricity with full sun. Panels can also produce power under cloudy skies – 50 to 70 percent of peak output with bright overcast and 5 to 10 percent with dark overcast. The site receives approximately 300 days of sunshine per year, roughly the same as Houston, Tex. On average this site generates 780 MWhs of power per year.

Battery Energy Storage System (BESS)

The Glacier Battery Demonstration Project was installed in early 2017. The 2 MW / 4.4 MWh lithium-ion battery storage system is located adjacent to the existing substation in Glacier, Wash., in Whatcom County. The Glacier battery serves as a short-term backup power source (up to 2.2 hours at capacity with a full charge) to a core "island" of businesses and residences during outages, reduces system load during periods of high demand, and helps balance energy supply and demand. The project was funded in part by a $3.8 million Smart Grid Grant from the State of Washington Department of Commerce. Between January and June, 2018, Pacific Northwest National Laboratory (PNNL) performed two use test cases. Since then, PSE has continued to test the battery's capabilities under planned outage scenarios – working toward the goal of successfully responding to unplanned outages.

Figure D-4 presents details about the company's wind, solar and battery storage resources.

3 / Outback Power Systems (now Silicon Energy) in Arlington produced the first solar panels in Washington. The Wild Horse Facility was Outback Power Systems' launch facility, utilizing 315 of their panels. The remaining panels were produced by Sharp Electronics in Tennessee.

Figure D-4: PSE's Owned Wind, Solar and Battery Storage Resources

POWER TYPE	UNITS	PSE OWNERSHIP	NET MAXIMUM CAPACITY (MW)
Wind	Hopkins Ridge	100%	157
Wind	Lower Snake River, Phase 1	100%	343
Wind	Wild Horse	100%	273
Total Wind			**773**
Solar	Wild Horse Solar Demonstration Project	100%	0.5
Energy Storage	Glacier Battery Demonstration Project	100%	2.0
Total Solar and Storage			**2.5**
Total Wind, Solar and Battery Storage			**775.5**

Supply-side Contract Resources

Long-term contracts consist of agreements with independent producers and other utilities to supply electricity to PSE. Fuel sources include hydropower, wind, solar, natural gas, coal, waste products and system deliveries without a designated supply resource. These contracts are summarized in Figure D-5. Short-term wholesale market purchases negotiated by PSE's energy trading group are not included in this listing.

POINT ROBERTS PPA. This contract provides for power deliveries to PSE's retail customers in Point Roberts, Wash. The Point Roberts load, which is physically isolated from PSE's transmission system, connects to British Columbia Hydro's electric distribution facilities. PSE pays a fixed price for the energy during the term of the contract.

BAKER REPLACEMENT. Under a 20-year agreement signed with the U.S. Army Corps of Engineers (COE) PSE provides flood control for the Skagit River Valley. Early in the flood control period, we draft water from the Upper Baker reservoir at the request of the COE. Then, during periods of high precipitation and runoff between October 15 and March 1, we store water in the Upper Baker reservoir and release it in a controlled manner to reduce downstream flooding. In return, PSE receives a total of 7,000 MWhs of power and 7 MW of net maximum capacity from BPA in equal increments per month for the months of November through February to compensate for the lower generating capability caused by reduced head due to the early drafting at the plant during the flood control months.

PACIFIC GAS & ELECTRIC COMPANY (PG&E) SEASONAL EXCHANGE. Under this system-delivery power exchange contract, each calendar year PSE exchanges with PG&E 300 MW of seasonal capacity, together with 413,000 MWh of energy, on a one-for-one basis. PSE is a winter-peaking utility and PG&E is a summer-peaking utility, so PG&E has the right to call for the power in the months of June through September, and PSE has the right to call for the power in the months of November through February.

CANADIAN ENTITLEMENT RETURN. Under a treaty between the United States and Canada, one-half of the firm power benefits produced by additional storage capability on the Columbia River in Canada accrue to Canada. PSE's benefits and obligations from this storage are based on the percentage of our participation in the Columbia River projects. Agreements with the Mid-Columbia PUDs specify PSE's share of the obligation is to return one-half of the firm power benefits to Canada during peak hours until the expiration of the PUD contracts or expiration of the Columbia River Treaty, whichever occurs first. This is energy that PSE provides rather than receives, so it is a negative number. The energy returned during 2018 was approximately 18 aMW with a peak capacity return of 32.5 MW. The Columbia River Treaty has no end date but can be terminated after 2024 with 10 years' notice. The United States and Canada recently concluded the ninth round of negotiations to modernize the treaty to ensure the effective management of flood risk, provide a reliable and economical power supply, and improve the ecosystem.

COAL TRANSITION PPA. Under the terms of this agreement, PSE began to purchase 180 MW of firm, baseload coal transition power from TransAlta's Centralia coal plant in December 2014. On December 1, 2015, the contract increased to 280 MW. From December 2016 to December 2024 the contract is for 380 MW, and in the last year of the contract, 2025, volume drops to 300 MW. This contract conforms to a separate TransAlta agreement with state government and the environmental community to phase out coal-fired power generation in Washington by 2025. In 2011, the state Legislature passed a bill codifying a collaborative agreement between TransAlta, lawmakers, environmental advocacy groups and labor representatives. The timelines agreed to by the parties enable the state to make the transition to cleaner fuels, while preserving the family-wage jobs and economic benefits associated with the low-cost, reliable power provided by the Centralia plant. The legislation allows long-term contracts, through 2025, for sales of coal transition power associated with the 1,340 MW Centralia facility, Washington's only coal-fired plant.

KLONDIKE III PPA. PSE's wind portfolio includes a power purchase agreement with Avangrid Renewables[4] for a 50 MW share of electricity generated at the Klondike III wind farm in Sherman County, Ore. The wind farm has 125 turbines with a project capacity of nearly 224 MW. This agreement remains in effect until November 2027.

4 / Formerly Iberdrola

LUND HILL SOLAR PPA. PSE has executed a 20-year power purchase agreement with Avangrid Renewables (through the project company Lund Hill Solar, LLC) to purchase the output from the Lund Hill Solar Project, to be located in Klickitat County, Wash. The project has an expected online date in March 2021. The output from the facility will be used to serve subscribers to PSE's new Green Direct program (Schedule 139), which is described in the Demand-side Resources section of this appendix.

SKOOKUMCHUCK WIND PPA. PSE has executed a 20-year power purchase agreement with Renewable Energy Systems (RES) to purchase the output from the Skookumchuck Wind Project.[5] The wind project is currently in development in Thurston and Lewis counties and is scheduled to be operational by the end of 2020.[6] Along with the output from Lund Hill Solar facility, the Skookumchuck facility output will be used to serve subscribers to PSE's Green Direct program (Schedule 139), which is described in the Demand-side Resources section of this appendix.

ENERGY KEEPERS PPA. PSE has entered into an agreement with Energy Keepers, Inc., the tribally owned corporation of the Confederated Salish and Kootenai Tribes, to purchase 40 MW of zero carbon energy produced by the Selis Ksanka Qlispe hydroelectric project through July of 2035.

SPI BIOMASS PPA. PSE has entered into a 17-year contract with Sierra Pacific Industries (SPI) to purchase 17 MW of renewable energy from SPI's Mt. Vernon Mill starting in 2021. SPI's cogeneration facility is an operational plant that uses wood byproducts from its lumber manufacturing process to generate steam used to make electricity and heat kilns to dry lumber. An air pollution control device filters out fine particles and other emissions from the burning wood so that what is released into the atmosphere comes out clean.

BPA CAPACITY PRODUCT. Under a five-year agreement beginning in January 2022, the Bonneville Power Administration will offer to sell PSE up to 100 MW of surplus power generated from the Federal Columbia River Power System. Hydroelectricity can quickly increase and decrease to meet power demand, and help the region achieve its renewable goals by dovetailing with more variable output resources such as wind and solar.

5 / PSE was notified on 10/24/2019 that Southern Power Company had purchased the project.
6 / The estimated in service COD is November 2, 2020.

MSCG SYSTEM PPA. PSE has entered into a Western System Power Pool (WSPP) agreement with the Morgan Stanley Commodities Group (MSCG) for a 4-year, 363-day, system PPA to deliver 100 MW of firm heavy load hour (HLH) energy in Q1 and Q4 only, beginning in January 2022.

GOLDEN HILLS WIND PPA. PSE has executed a 20-year power purchase agreement with Avangrid Renewables for the output of a 200 MW wind farm to be built in Sherman County, Ore. Avangrid expects to complete the project by late 2021. The project will help PSE meet its goals to reduce carbon dioxide emissions while providing additional capacity to serve customers, particularly during winter periods of high electricity demand.

RFP RESOURCE PPA. PSE expects to complete execution of a 20-year power purchase agreement in early 2021. For the purposes of the draft IRP, which files in January, it is labeled as a generic RFP resource.

HYDROELECTRIC PPAs. Among PSE's power purchase agreements are several long-term contracts for the output of production from hydroelectric projects within its balancing area. These contracts are shown in Figure D-5 below and have the designator "Hydro – QF" for qualifying facility. The projects are run-of-river and do not provide any flexible capacity.

SCHEDULE 91 CONTRACTS. PSE's portfolio includes a number of electric power contracts with small power producers in PSE's electric service area (see Figure D-5). These qualifying facilities offer output pursuant to WAC chapter 480-106. WAC 480-106-020 states: "A utility must purchase, in accordance with WAC 480-106-050 Rates for purchases from qualifying facilities, any energy and capacity that is made available from a qualifying facility: (a) Directly to the utility; or (b) Indirectly to the utility in accordance with subsection (4) of this section." A qualifying facility is defined in WAC 480-106-007 as a "cogeneration facility or small power production facility that is a qualifying facility under 18 C.F.R. Part 292 Subpart B."

Figure D-5: Long-term Contracts for Electric Power Generation (continued next page)

NAME	POWER TYPE	CONTRACT EXPIRATION	CONTRACT CAPACITY (MW)
Pt. Roberts[1]	System	9/30/2022	8
Baker Replacement	Hydro	9/30/2029	7
PG&E Seasonal Exchange-PSE	System	Ongoing	300
Canadian Entitlement Return	Hydro	09/15/2024	(32.5)
Coal Transition PPA	Transition Coal	12/31/2025	380[2]
Klondike III PPA	Wind	11/30/2027	50
Energy Keepers PPA	Hydro	7/31/2035	40
SPI Biomass PPA	Biomass	12/31/2037	17
BPA Capacity Product PPA	Hydro	12/31/2026	100
MSCG System PPA	System	12/31/2026	100
Golden Hills Wind PPA	Wind	6/30/2042[3]	200
RFP Resource	Wind	TBD	350
Lund Hill Solar	Schedule 139 – Solar	7/01/2041[4]	150
Skookumchuck Wind	Schedule 139 - Wind	12/31/2039[5]	136.8
Twin Falls PPA	Hydro-QF	3/018/2025	20
Koma Kulshan PPA	Hydro-QF	3/31/2037	13.3
Weeks Falls PPA	Hydro-QF	12/01/2022	4.6
Farm Power Rexville	Schedule 91 - Biogas	12/31/2023	0.75
Farm Power Lynden	Schedule 91 - Biogas	12/31/2023	0.75
Rainier Biogas	Schedule 91 – Biogas	12/31/2023	1.0
Vanderhaak Dairy	Schedule 91 – Biogas	12/31/2023	0.60[6]
Edaleen Dairy	Schedule 91 – Biogas	12/31/2023	0.75
Van Dyk - Holsteins Dairy	Schedule 91 – Biogas	12/31/2023	0.47
Blocks Evergreen Dairy	Schedule 91 – Biogas	12/31/2031	0.19
Emerald City Renewables[7]	Schedule 91 – Biogas	12/31/2029	4.50
Emerald City Renewables 2	Schedule 91 – Biogas	12/31/2031	4.50
Skookumchuck Hydro	Schedule 91 – Hydro	1/31/2024	1.0
Black Creek	Schedule 91 – Hydro	3/25/2031	4.2
Nooksack Hydro	Schedule 91 – Hydro	12/31/2023	3.5
Sygitowicz – Kingdom Energy[8]	Schedule 91 – Hydro	12/31/2030	0.448
Island Solar[9]	Schedule 91 – Solar	12/31/2023	0.075
Finn Hill Solar (Lake Wash SD)	Schedule 91 – Solar	12/31/2023	0.355
CC Solar #1, LLC and CC Solar #2, LLC (combined)	Schedule 91 – Solar	1/1/2026	0.026
IKEA	Schedule 91 – Solar	12/31/2031	0.828
TE – Fumeria	Schedule 91 – Solar	12/31/2031	4.99
TE – Penstemon	Schedule 91 – Solar	12/31/2031	4.99

NAME	POWER TYPE	CONTRACT EXPIRATION	CONTRACT CAPACITY (MW)
TE – Typha	Schedule 91 – Solar	12/31/2031	4.99
TE – Urtica	Schedule 91 – Solar	12/31/2031	4.99
TE – Camas	Schedule 91 – Solar	12/31/2031	4.99
Iron Horse Solar	Schedule 91 – Solar	12/31/2030	4.5
Osprey	Schedule 91 – Solar	12/31/2030	0.95
Heelstone Energy – Westside Solar	Schedule 91 – Solar	12/31/2031	4.99
Heelstone Energy – Dry Creek Solar	Schedule 91 – Solar	12/31/2031	4.99
Cypress Renewables – Gholson Solar	Schedule 91 – Solar	12/31/2032	4.99
IKEA	Schedule 91 – Solar	12/31/2031	0.828
GCSD PSE3 LLC	Schedule 91 – Solar	12/31/2031	4.0
Knudson Wind	Schedule 91 – Wind	12/31/2023	0.108
3 Bar-G Wind	Schedule 91 – Wind	12/31/2023	0.120 [10]
Swauk Wind	Schedule 91 – Wind	12/31/2023	4.25
Total			**1,923**

NOTES

1. The contract to provide power to PSE's Point Roberts customers expired on 9/30/2019 and the new contract with a three-year term was negotiated between PSE and PowerEx, commencing October 1, 2019. Point Roberts is not physically interconnected to PSE's system, and relies on power from a single intertie point on BC Hydro's distribution grid.

2. The capacity of the TransAlta Centralia PPA is designed to ramp up over time to help meet PSE's resource needs. According to the contract, PSE will receive 280 MW from 12/1/2015 to 11/30/2016, 380 MW from 12/1/2016 to 12/31/2024 and 300 MW from 1/1/2025 to 12/31/2025.

3. A 1-year system PPA for interim capacity has also been signed in the event that COD is pushed past December 2021, but no later than June 20, 2022.

4. 20-year term subject to final COD date, now anticipated in Q1, 2021.

5. 20-year term subject to final COD date.

6. VanderHaak has two generators with a combined capacity of .60 MW. However, VanderHaak primarily runs only the larger generator, which has a capacity of .45 MW.

7. Emerald City Renewables was formerly known as BioFuels Washington.

8. The site was purchased on May 1, 2020 by Hillside Clean Energy with PSE's consent.

9. Ownership was transferred to the Port of Coupeville on July 1, 2020 with PSE's consent.

10. Agreement originally for 1.395 MW but only 0.120 MW was constructed and the contract was amended to reflect this change.

Supply-side Transmission Resources

Mid-C Transmission Resources

Transmission capacity to the Mid-Columbia (Mid-C) market hub gives PSE access to the principal electricity market hub in the Northwest, which is one of the major trading hubs in the Western Electricity Coordinating Council (WECC). It is the central market for northwest hydroelectric generation. PSE has 2,481 MW of transmission capacity to the Mid-C market; of that, 2,031 MW is contracted from BPA on a long-term basis and 450 MW is owned by PSE.[7] The BPA transmission rights are owned by PSE Merchant. The 450 MW of transmission is sold by PSE Transmission as the Transmission Provider. Currently, PSE's 449 customers hold the rights to the 450 MW of transmission; however, when these rights are not fully utilized by the 449 customers, these transmission rights are allocated to PSE Merchant or sold on OASIS. PSE's Mid-C transmission capacity is detailed in Figure D-6 below; approximately 1,500 MW of this capacity to the Mid-C wholesale market comprises a significant portion of the capacity required to meet PSE's peak need.[8]

7 / PSE also owns transmission and transmission contracts to other markets in addition to the Mid-C market transmission detailed here.
8 / See Chapter 8, Electric Analysis, for a more detailed discussion of PSE reliance on wholesale market capacity to meet peak need.

Figure D-6: Mid-C Hub Transmission Resources

NAME	EFFECTIVE DATE	TERMINATION DATE	TRANSMISSION DEMAND (MW)
BPA Mid-C Transmission			
Midway	11/1/2017	11/1/2022	100
Midway	4/1/2008	11/1/2035	5
Rock Island	7/1/2007	7/1/2037	400
Rocky Reach [9]	11/1/2017	11/1/2022	100
Rocky Reach	11/1/2017	11/1/2022	100
Rocky Reach	11/1/2019	11/1/2024	40
Rocky Reach	11/1/2019	11/1/2024	40
Rocky Reach	11/1/2019	11/1/2024	40
Rocky Reach	11/1/2019	11/1/2024	5
Rocky Reach	11/1/2019	11/1/2024	55
Rocky Reach	9/1/2014	11/1/2031	160
Vantage	11/1/2017	11/1/2022	100
Vantage	12/1/2019	12/1/2024	169
Vantage	10/1/2013	3/1/2025	3
Vantage	11/1/2019	11/1/2024	27
Vantage	11/1/2019	11/1/2024	27
Vantage	11/1/2019	11/1/2024	27
Vantage	11/1/2019	11/1/2024	3
Vantage	11/1/2019	11/1/2024	36
Vantage	11/1/2019	11/1/2024	5
Wells	9/1/2018	9/1/2023	266
Vantage	3/1/2016	2/28/2021	23
Midway	10/1/2018	10/1/2023	115
Midway	3/1/2019	3/1/2024	35
Wells/Sickler	11/1/2018	11/1/2023	50
Vantage	11/1/2018	11/1/2023	50
Vantage	12/1/2019	11/1/2022	50
Total BPA Mid-C Transmission			**2,031**
PSE Owned Mid-C Transmission			
McKenzie to Beverly	-	-	50
Rocky Reach to White River	-	-	400
Total PSE Mid-C Transmission			**450**
Total Mid-C Transmission			**2,335**

9 / *Contract split between Mid-C and EIM Imports below*

EIM Transmission Resources

When PSE joined the Energy Imbalance Market (EIM) in October 2016, it redirected 300 MW of Mid-C transmission capacity contracted from BPA on an annual basis for EIM trades. Starting in June 2020, Mid-C transmission redirected for use in the EIM was reduced to 150 MW in order to align with PSE's market-based rate authority. This is a required amount to maintain market-based authority and still gives PSE the capability to redirect beyond this amount for use in the EIM. Although these redirects reduce transmission capacity available to support PSE's peak need, PSE still maintains sufficient capacity to meet the winter peak. The amount of redirected Mid-C transmission will need to be renewed on an ongoing basis, and this will allow PSE to reevaluate its EIM transfer capacity needs in light of future winter peak needs. Figure D-7 details the transmission capacity currently redirected for EIM.

An additional 300 MW reserved under the PG&E Seasonal Exchange contract is redirected for EIM during certain months of the year on an as-feasible basis. When PSE's obligations to PG&E during summer months prevent this redirect, PSE instead redirects its existing Mid-C transmission, bringing total redirected Mid-C transmission for EIM during summer months up to 450 MW.

Figure D-7: Mid-C Hub Transmission Resources Redirected for EIM as of 1/1/2021

NAME	EFFECTIVE DATE	TERMINATION DATE	TRANSMISSION DEMAND (MW)
BPA Mid-C Transmission Redirected for EIM			
Rocky Reach	11/1/2017	11/1/2022	150
Total BPA Mid-C Transmission Redirected for EIM			**150**

Demand-side Resources

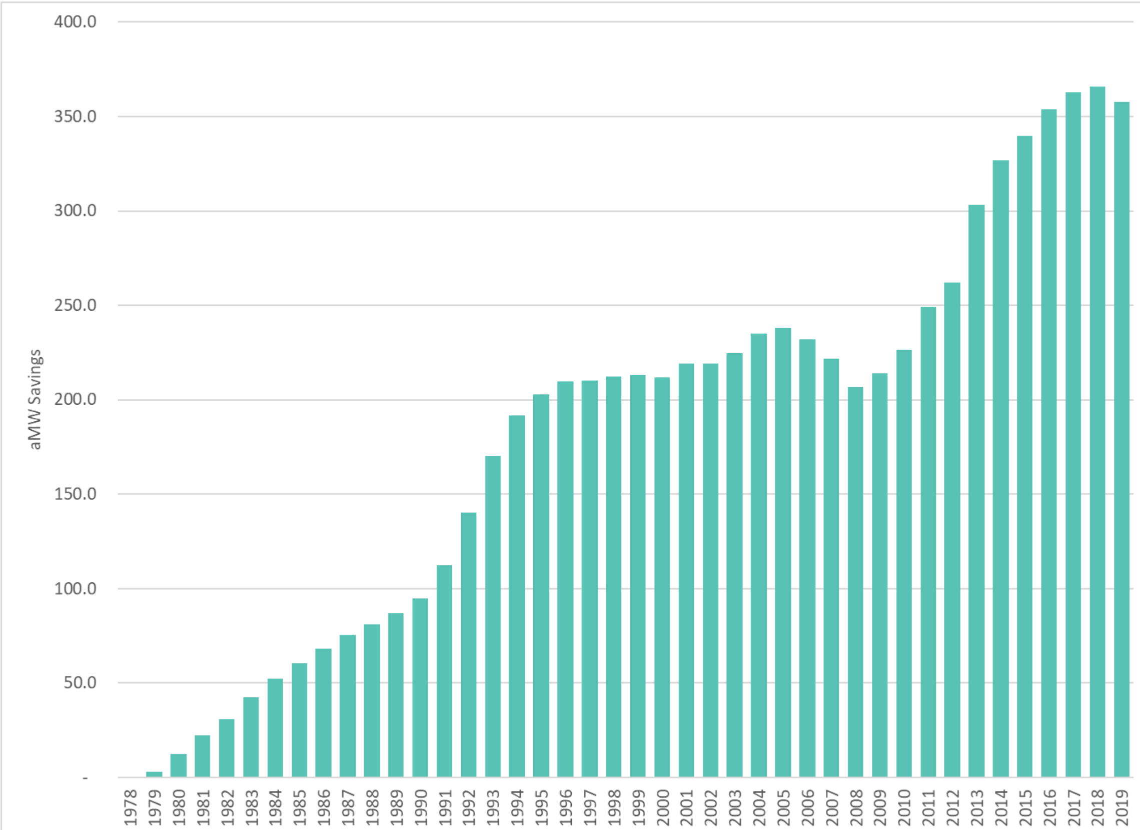
Energy reduction and energy production programs that contribute to meeting need by reducing demand are called demand-side resources (DSR). These are often implemented on the customer side of the meter. DSR programs currently offered through PSE include:

- **ENERGY EFFICIENCY**, implemented by PSE's Customer Energy Management group
- **DISTRIBUTION EFFICIENCY**, managed by PSE's System Planning department
- **GENERATION EFFICIENCY**, evaluated by PSE's Customer Energy Management group (This represents energy efficiency opportunities at PSE generating facilities.)
- **DISTRIBUTED GENERATION**, overseen by PSE's Customer Energy Management group (with the exception of distributed solar photovoltaics, which is overseen by the Customer Renewable Energy Programs group)
- **DEMAND RESPONSE** pilots, currently overseen by PSE's Customer Energy Management group

PSE has been a leader in the Pacific Northwest when it comes to implementation of demand-side energy efficiency resource programs. Since 1978, annual first-year savings (as reported at the customer meter) have grown by more than 300 percent, from 9 aMW in 1978 to 27.6 aMW in 2019. On a cumulative basis, these savings reached a total of 358 aMW by 2019. (Savings are adjusted for measure life and then retired so they no longer count towards the cumulative savings.[10]) To achieve these savings over the 1978 to 2019 period, the company spent a total of approximately $1.57 billion in incentives to customers and for program administration.

10 / For the purposes of the IRP analysis, measure life is assumed to be 10 years.

Figure D-8: Cumulative Electric Energy Efficiency Savings from DSR, 1978 through 2019



Energy Efficiency

Energy efficiency is by far PSE's largest electric demand-side resource. It consists of measures and programs that replace existing building components and systems such as lighting, heating, water heating, insulation, appliances, etc. with more energy efficient ones. There are two types of measures: "retrofit measures" (when replacement is cost effective before the equipment reaches its end of life); and lost opportunity measures (when replacement is not cost effective until existing equipment burnout).

PSE energy efficiency programs serve all types of customers – residential (including low income), commercial and industrial. Program savings targets are established every two years in collaboration with key external stakeholders represented by the Conservation Resource Advisory Group (CRAG) and the IRP public participation process. The majority of electric energy efficiency programs are funded using electric "conservation rider" funds collected from all customer classes.[11]

11 / See Electric Schedule 120, Electricity Conservation Service Rider, for more information.

In the most recently completed program cycle, the 2018-19 tariff period, energy efficiency achieved a total savings of 61.4 aMW; the target for the current 2020-21 program cycle is 60.0 aMW. Some of the changes in the 2020-21 program cycle are noted below.[12]

- HB1444 made high efficiency LED lighting the baseline technology, so the general service LED lighting savings, which a huge part of the residential program savings will no longer be offered and will be replaced with other program offerings. The home energy assessment program which relied on LED savings will be repurposed to focus on hard to reach customers only.
- Expanded distribution channels for high efficiency space heating and water heating heat pump products for residential customers.
- Expanded home energy reports program to enroll more customers.
- Target moderate income residences that are not qualified under the low income category for space, water and weatherization measures.
- Increased incentives for lighting and non-lighting measures in the commercial and industrial sectors
- Expanded distribution channels for delivery of heat pumps in commercial and industrial sectors.

12 /*See 2020-21 Biennium Conservation Plan Overview for more details on efficiency programs, especially low-income weatherization programs.*

The 2020-2021 electric energy efficiency programs are targeted to save 60.05 aMW of electricity at a cost of just under $194 million.

Distribution Efficiency

The Production and Distribution Efficiency program includes implementing energy conservation measures within PSE's own distribution facilities that prove cost-effective, reliable and feasible.

For transmission and distribution (T&D) efficiency, improvements are implemented at PSE's electric substations. These improvements focus on measures like phase balancing and conservation voltage reduction (CVR). The methodology used to determine CVR savings is the Simplified Voltage Optimization Measurement and Verification Protocol provided by the Northwest Power and Conservation Council Regional Technical Forum.[13]

Figure D-9 below lists the CVR-related projects completed to date and planned for the 2020-21 period. In future years, a significant expansion in CVR project implementation is planned, tied to the implementation of the Advanced Metering Infrastructure (AMI) project and substation automation project. These two projects will enable Volt-Var optimization (VVO), an improved CVR method that allows for deeper levels of savings compared to PSE's current CVR implementation method of line drop compensation (LDC).

Savings associated with CVR are affected by several variables, including but not limited to the increasing penetration of distributed energy resources (DERs) that is expected in the future. Therefore, the savings from these projects can vary significantly. PSE is currently investigating the need for a study that provides an updated energy savings methodology for Volt-Var CVR projects. Currently, the first Volt-Var CVR project is expected to launch in 2023.

13 / *rtf.nwcouncil.org*

Figure D-9: Energy Savings from Conservation Voltage Reduction, Cumulative Savings to Date, kWh

Substation	Year of Execution	Date of Completion	Date of QC of Non-payment Request	kWh Savings / YEAR	Savings as % of Baseline kWh
South Mercer	2013	11/1/2013	12/18/2013	607,569	1.3%
Mercerwood	2013	12/8/2013	12/18/2013	357,240	0.9%
Mercer Island	2014	8/8/2014	9/22/2014	859,586	1.3%
Britton	2014	12/5/2014	12/24/2014	636,197	5.6%
Panther Lake	2015/2016	8/27/2015	6/23/2016	804,326	1.3%
Hazelwood	2015/2016	9/18/2015	6/23/2016	1,352,149	1.4%
Pine Lakes	2015/2016	9/17/2015	6/23/2016	1,163,150	1.3%
Fairwood	2017/2018	5/1/2018	11/13/2018	768,367	1.2%
Rhode Lakes	2017/2018	5/23/2018	11/13/2018	1,639,803	1.6%
Rolling Hills	2017/2018	5/24/2018	11/2/2018	1,359,515	1.5%
Phantom Lake	2018/2019	12/19/2018	4/16/2019	343,748	0.8%
Overlake	2018/2019	12/6/2019	12/27/2019	326,644	1.0%
Lake McDonald	2020	5/26/2020		404,699	1.0%
Maplewood	2020	In progress		1,534,573	estimate
Cambridge	2021	In progress		956,084	estimate
Marine View	2021	In progress		1,600,000	estimate
Klahanie	2021	In progress		1,072,000	estimate
Norway Hills	2021	In progress		1,356,225	estimate
Average to Date				**952,326**	**1.6%**
Total to Date		**11/19/2020**		**10,218,294**	

Generation Efficiency

In 2014, PSE worked with the CRAG to refine the boundaries of what to include as savings under generation efficiency. It was determined that only parasitic loads[14] served directly by a generator would be included in the savings calculations as available for generation efficiency upgrades; generators whose parasitic loads are served externally – from the grid – would not be included. Using this definition, PSE completed site assessments in 2015 and the assessments did not yield any cost-effective measures. Most of the opportunities were in lighting, and very low operating hours made these opportunities not cost effective.

14 / Electric generation units need power to operate the unit, including auxiliary pumps, fans, electric motors and pollution control equipment. Some generating plants may receive this power externally, from the grid; however, many use a portion of the gross electric energy generated by the unit for operations – this is referred to as the "parasitic load."

Analyses performed during 2020-2021 planning revealed that there are no cost-effective measures available for PSE generation facilities. Program staff will continue examination of these facilities in 2020 and adjust PSE's 2021 Annual Conservation Plan, should conservation opportunities in generating facilities become cost effective.[15]

Distributed Generation

PSE offers cogeneration/combined heat and power incentives under its commercial and industrial programs. However, to date no project has been implemented.

Renewable distributed generation programs are discussed under "Customer Renewable Energy Programs" in the next section.

Demand Response

PSE filed a draft system-wide Demand Response (DR) RFP with the UTC on May 4 2020, when the capacity shortfall by 2024 was expected to be 250 MW. The RFP asked for all technologies including smart thermostats, water heater communication modules and behavioral modification techniques. No minimum capacity offer was required to qualify to bid. The DR RFP solicited bids for both a system-wide electric demand response program as well as smaller (3 to 5 MW, 3 to 5k MBh[16]), geographically targeted, electric and natural gas DR programs. Bidders for Targeted Demand Response (TDR) would be responsible for providing localized load curtailment beginning in 2021.

Shortly before the UTC was to rule on PSE's Draft All-Source and DR RFPs in mid-July 2020, PSE's F2020 load forecast indicated a significant reduction in need by 2024. Absent the originally forecasted 2024 capacity need, PSE petitioned to withdraw both draft RFPs. The UTC granted the request on October 15, 2020, with the understanding that PSE will re-submit updated All-Source and DR RFPs by April 1, 2021.

In the meantime, PSE's Customer Energy Management department plans to operate geographically targeted pilots in both a natural gas (Duvall) and an electric (Bainbridge Island) program in 2021.

15 / 2021 Annual Conservation Plan
16 / MBh = thousand Btu per hour

Demand-side Customer Programs

Customer Renewable Energy Programs

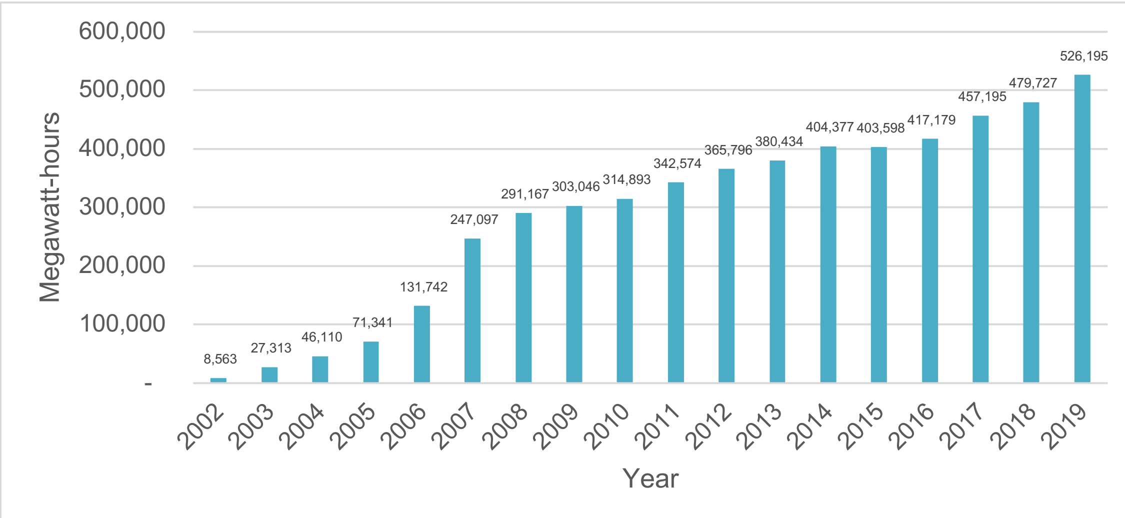
PSE's customer renewable energy programs remain popular options. The Green Power Program serves customers who want to purchase additional renewable energy, and Net Metering and Local Energy Development programs serve customers who generate renewable energy on a small scale. Our customers find value as well as social benefits in these programs, and PSE embraces and encourages their use.

GREEN POWER PROGRAM. Launched in 2001, PSE's Green Power Program allows customers to voluntarily purchase retail electric energy from qualified renewable energy resources. In 2009, we began working to increase participation in the program with 3Degrees, a third-party renewable energy credits (REC) broker that has developed and refined education and outreach techniques while working with other utility partners across the country. Since then, the program has grown to over 60,000 participants by the end of 2019. In addition, the number of megawatt-hours purchased increased by approximately 5 percent from 2017 to 2018 and 9.6 percent from 2018 to 2019, ending the period with sales amounting to 526,195 MWhs in 2019.

Top 10

PSE has been recognized as one of the country's top 10 utilities for Renewable Energy Sales and Total Number of Green Power Participants by the National Renewable Energy Laboratory since 2005.

Figure D-10: Green Power Megawatt-hours Sold, 2002-2019



The Green Power Program has built a portfolio of RECs generated from a wide variety of technologies. In 2017, PSE issued an RFQ that resulted in competitively awarding multi-year REC contracts to Bonneville Environmental Foundation and 3Degrees to help supply the balance of our Green Power program portfolio needs for up to three years, beginning in 2018 and expiring at the end of 2020. These suppliers provide the program with RECs primarily from Pacific Northwest renewable energy facilities. In mid-2020, PSE issued an RFQ seeking RECs to supply the Green Power program for the years 2021-2023. In addition, the Green Power Program directly purchases RECs from small, local and regional producers in order to support the development of small-scale renewable resources. These have included FPE Renewables, Farm Power Rexville, Edaleen Cow Power, Van Dyk-S Holsteins, Rainier Biogas, 3Bar G Community Wind, First Up! Knudson Community Wind, Ellensburg Community Solar, Swauk Wind and LRI Landfill Gas. Some of our small-scale solar contracts such as Skagit Community Solar, APSB Community Solar, Maple Hall Community Solar, Anacortes Library Community Solar and Greenbank Community Solar will expire at the end of 2020. Many of these entities also provide power to PSE under the Schedule 91 contracts discussed above.

The increase in the number of utility-scale solar projects in Idaho and Oregon has allowed PSE to dramatically increase the number of RECs sourced from solar projects. PSE's preference is to source RECs first from projects located in Washington, and then from Oregon and Idaho. However, the supply of Pacific Northwest RECs continues to tighten as voluntary program sales have grown, and more resources are dedicated to serving compliance targets. This has made it more difficult to source all of our supply from this region. In an effort to maintain current program pricing, we have begun sourcing from other locations in the WECC, including Montana, Utah, Colorado, California and British Columbia. We believe this trend will continue as CETA compliance increases demand for renewable energy in the region.

GREEN POWER COMMUNITY GRANTS. Over the past 13 years, the Green Power Program has also committed over $1,850,000 in grant funding to 15 cities, 6 community service organizations and 10 low income multi-family housing agencies for solar demonstration projects. For example, in 2019, PSE awarded solar grants to 10 non-profit organizations specializing in low income or transitional multi-family housing. Anacortes Housing Authority, Community Youth Services, Family Support Center of South Sound, Homes First, King County Housing Authority, Kulshan Community Land Trust, Lummi Nation Housing Authority, Muckleshoot Housing Authority, Lydia Place and Opportunity Council received over $575,000 that resulted in more than 219 new kW of installed solar. In 2020, PSE issued a solicitation to award up to $1,000,000 in grant funding for solar installations to non-profits, public housing authorities or tribal entities serving low income or Black, Indigenous and People of Color (BIPOC) community members in PSE’s electric service area. Projects are expected to be installed in 2021.

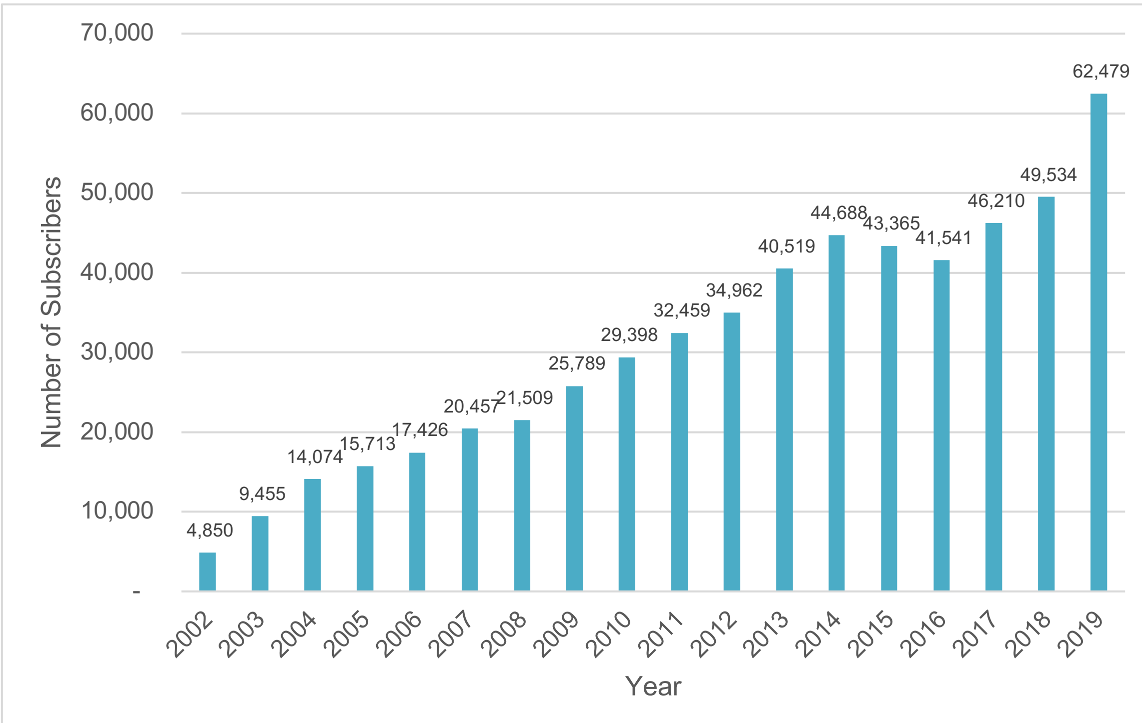
GREEN POWER RATES. In September 2016, PSE received approval from the Washington Utilities and Transportation Commission (WUTC) to reduce Green Power rates. The standard rate for green power dropped from $0.0125 per kWh to $0.01 per kWh. Customers can purchase 200 kWh blocks for $2.00 per block with a two-block minimum or choose to participate in the “100% Green Power Option” introduced in 2007. This option adjusts the amount of the customer’s monthly green power purchase to match their monthly electric usage. The large-volume green power rate dropped from $0.006 per kWh to $0.0035 per kWh for customers who purchase more than 1,000,000 kWh annually. This product has attracted approximately 30 customers since it was introduced in 2005.

In 2019, the average residential customer purchase was 718 kWh per month, and the average commercial customer purchase was 1,957 kWh. The average 2019 large-volume purchase under Schedule 136, by account, was 31,260 kWh per month.

SOLAR CHOICE. In September 2016, the WUTC approved PSE’s Solar Choice program, a renewable energy product offering for residential and small to mid-size commercial customers. Similar to the Green Power program, Solar Choice allows customers to voluntarily purchase retail electric energy from qualified renewable energy resources; but in this case, all of the resources supplied are solar energy facilities located in Washington, Oregon and Idaho. Customers can elect to purchase solar in $5.00 blocks for 150 kilowatt-hours. The purchase is added to their monthly bill. The program was officially launched to customers in April 2017, and current participation stands at 7,654 participants. Collectively, these customers purchased 18,563 megawatt-hours of solar energy in 2019, a 112 percent increase from 2018 to 2019.

Figure D-11 illustrates the number of subscribers in our Green Power and Solar Choice offerings by year. Of our 62,479 Green Power and Solar Choice subscribers at the end of 2019, 61,554 were residential customers, 856 were commercial accounts, and 79 accounts were assigned under the large-volume commercial agreement. Cities with the most residential and commercial participants include Bellingham with 7,350, Olympia with 6,909 and Kirkland with 4,564.

Figure D-11: Green Power and Solar Choice Subscribers, 2002-2019



GREEN DIRECT. The Green Direct program launched on September 30, 2016 after WUTC approval. Like the Green Power program and Solar Choice, Green Direct falls under the rules governing utility green pricing options found in Washington RCW 19.29A, Voluntary Option to Purchase Qualified Alternative Energy Resources. Green Direct is a product that allows the utility to procure and sell fully bundled renewable energy to large commercial (10,000 MWh per year or more of load in PSE's service area) and government customers from specified wind and solar resources.

For Phase I, PSE signed a 20-year power purchase agreement for the output from the 137 MW Skookumchuck Wind project in Lewis County. Customers could elect to enroll for terms of 10, 15 or 20 years. The customer continues to receive and pay for all of the standard utility services for safety and reliability. Customers are charged for the total cost of the energy from the new plant, but receive a credit for the energy-related power costs from the company.

Phase I of Green Direct held its first open enrollment period in November and December 2016, followed by a second open enrollment period that opened on May 1, 2017. As of June 30, 21 customers had fully-subscribed to the wind facility. Enrollees include companies like Starbucks, Target Corporation and REI, and government entities like King County and the City of Olympia.

For Phase II, PSE issued a Request for Proposals to identify a new resource (or resources) in August 2017. In early 2018, PSE selected a 120 MW solar project to be built in south-central Washington that is expected to begin operations in 2021. Following selection, PSE proposed a blended rate of the Phase I wind project and Phase II solar project, which the WUTC approved in July 2018. Phase II enrollment opened on August 31 at 1:00 pm, and was completely subscribed by 16 customers; four were wait listed. PSE subsequently requested an expansion of the project size from 120 MW to 150 MW, which the WUTC approved. The expansion allowed all 20 customers to participate. Phase II customers include T-Mobile, Amazon, Walmart, UW Bothell, Bellevue College, six Washington State agencies, the Issaquah School District, Providence Health & Services, Kaiser Permanente, Port of Bellingham, the cities of Kent and Redmond, and several customers from Phase I requesting additional supply.

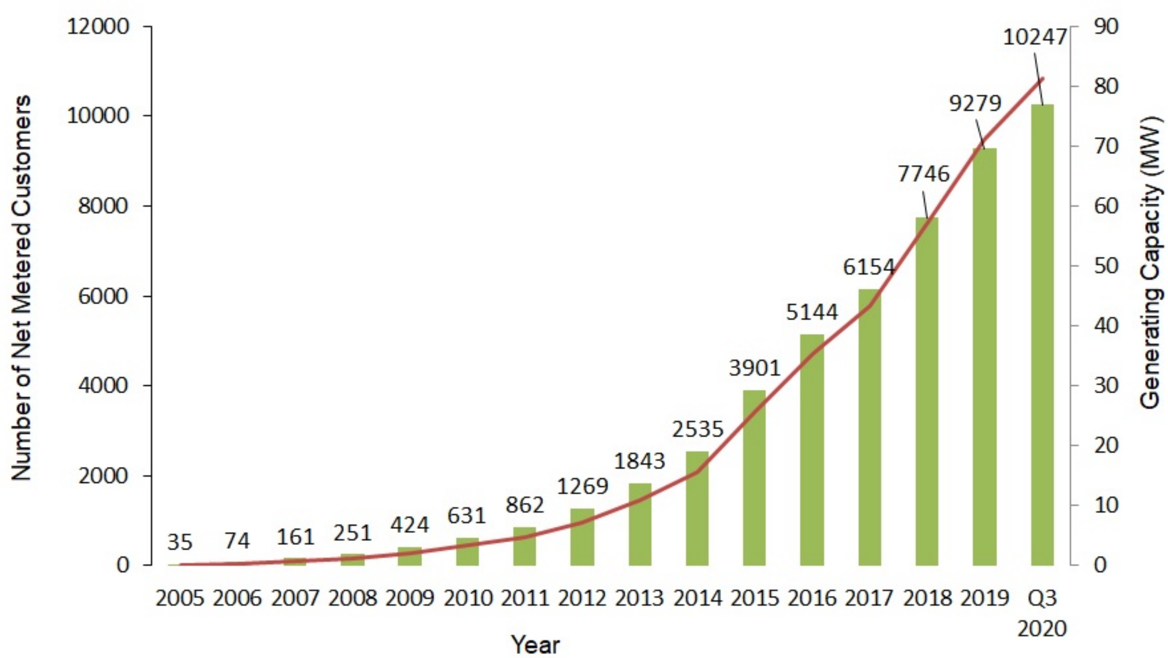
Customer Connected Renewables Programs

PSE offers two customer programs for customers who install their own small-scale generation, a net metering program and the Washington State Renewable Energy Production Incentive Program. These are not mutually exclusive, and the majority of customer-generators were enrolled in both programs until the Production Incentive Program closed to new participants in 2019.

The **NET METERING PROGRAM**, defined in Rate Schedule 150 and governed by RCW 80.60, began in 1999, and was most recently updated by Washington State Senate bill ESSB 5223 on July 28, 2019. Net metering provides a way for customers who generate their own renewable electricity to offset the electricity provided by PSE. The amount of electricity that the customer generates and sends back to the grid is subtracted from the amount of electricity provided by PSE, and the net difference is what the customer pays for on a monthly basis. A kWh credit is carried over to the next month if the customer generates more electricity than PSE supplies over the course of a month. The “banked” energy can be carried over until March 31, when the account is annually reset to zero according to state law. The interconnection capacity allowed under net metering is 100 kW AC.

Customer interest in small-scale renewables has increased significantly over the past 20 years, as Figure D-12 shows. The program has doubled the number of participating customers in the last four years, with strong growth continuing even after the closure of the State Production Incentive Program. In August of 2020, PSE celebrated its 10,000th net metered customer.

Figure D-12: Net Metered Customers, 1999-2020



The vast majority of customer systems (99 percent) are solar photovoltaic (PV) installations with an average generating capacity of 8 kW, but there are also small-scale hydroelectric generators and wind turbines. These small-scale renewable systems are distributed over a wide area of PSE's service territory. By mid-2020, PSE was net metering more than 80 MW (AC) of generating capacity.

Customer preference along with declining prices and federal tax incentives continues to drive customer solar PV adoption. Residential customers were 95 percent of all solar PV by number and 87 percent by nameplate capacity. In 2019, PSE revised Schedule 150 and streamlined the interconnection and net metering application process. We continue to examine our processes to allow for customer generation to scale up.

Figure D-13: Interconnected System Capacity by Type of System, as of Q3 2020

SYSTEM TYPE	NUMBER OF SYSTEMS	AVERAGE CAPACITY PER SYSTEM TYPE (kW [MW])	SUM OF ALL SYSTEMS BY TYPE (kW [MW])
Hybrid: solar/wind	16	9.3 [0.0093]	184 [0.184]
Micro hydro	6	15.7 [0.0177]	101 [0.101]
Solar array	10,196	8.0 [0.008]	80,993 [81]
Wind turbine	29	2.7 [0.0027]	80 [0.08]
Total	**10,247**	**8.0 [0.008]**	**81,359 [81.359]**

Figure D-14: Net Metered Systems by County

COUNTY	NUMBER OF NET METERS
Whatcom	2,126
King	3,342
Skagit	954
Island	485
Kitsap	1,031
Thurston	1,189
Kittitas	576
Pierce	536
Total	**10,247**

RENEWABLE ENERGY PRODUCTION INCENTIVE PAYMENT PROGRAM. The Washington State Renewable Energy Production Incentive Program is a production-based financial incentive for customers with solar, wind and bio-digester generating systems. PSE has voluntarily administered this state incentive to qualified customers under Schedule 151 since 2005.

In order for a PSE customer-generator to participate in Schedule 151, they must:

- Be a PSE customer with a valid interconnection agreement with PSE for the operation of their grid-connected renewable energy system.
- Have a system that includes production metering capable of measuring the energy output of the renewable energy system.
- Be certified (as named on the PSE account) by the Washington State Program Administrator as eligible for annual incentive payments.

In June 2019, the Washington State Program Administrator issued notice that this program's budget was fully obligated and PSE formally withdrew our voluntary participation effective December 12, 2019. PSE continues to administer annual incentive payments to all certified program participants, but customers installing new solar systems after December 12, 2019 are not eligible to participate in this program. Thus, the State Production Incentive Program is no longer a driver of solar energy adoption.

Annual Production Reporting and Payments. Annually, PSE measures and reports the kilowatt hours generated by participants' renewable energy systems and makes incentive payments to eligible customers as determined by the Washington State Program Administrator.

Legacy participants (those certified to participate by the Department of Revenue prior to October 1, 2017) with valid certifications will continue to receive payments of up to $5,000 per year for electricity produced through June 30, 2020 at rates ranging from $0.14 to $0.504 per kWh. Participants who obtained state certification on or after October 1, 2017 and who maintain ongoing eligibility requirements are eligible for up to eight years of annual incentive payments on kilowatt-hours generated from July 1, 2017 through June 30, 2029. The incentive rate for these participants ranges from $0.02 to $0.21 per kWh based on system size, technology and the date of certification.

Participant eligibility, rates, terms, payment limits and incentive payment amounts are determined by the Washington State Program Administrator.

Through 2019, PSE had administered to our customers over $72 million in production incentive payments. These payments are recovered through state tax credits. As PSE administers payments for State Fiscal Year 2020 production, we expect to be issuing another $19 million in payments to approximately 8,000 participating customers. 2020 will be the final payment year for 5,300 legacy program participants.

3. ELECTRIC RESOURCE ALTERNATIVES

This overview of alternatives for electric power generation describes both mature technologies and new methods of power generation, including those with near- and mid-term commercial viability. Within each section, resources are listed alphabetically.

COST ASSUMPTIONS. The generic resource costs for renewable, energy storage and thermal resources described in the following pages were aggregated from publicly available data sources including the National Renewable Energy Laboratory (NREL), the U.S. Energy Information Administration, Lazard, the Northwest Power and Conservation Council, various other National Laboratories and regional Integrated Resource Plans. Aggregated costs were then informed and adjusted through the stakeholder feedback process. Generic resource cost assumptions, including all data sources and averaging assumptions are available for review on the on the PSE IRP website.[17]

OPERATING CHARACTERISTICS. Generic resource operating characteristics were informed by PSE's experience, solar and wind data published by the NREL, and the Generic Resource Costs for Integrated Resource Planning report completed by consultant HDR for PSE in 2018, available for review on the PSE IRP website.[18]

17 / https://oohpseirp.blob.core.windows.net/media/Default/documents/Generic_Resource_Cost_Summary_PSE%202021%20IRP_post-feedback_v5.xlsx

18 / https://oohpseirp.blob.core.windows.net/media/Default/PDFs/HDR_Report_10111615-0ZR-P0001_PSE%20IRP_Rev4%20-%2020190123).pdf

Demand-side Resource Costs and Technologies

Demand-side resource (DSR) alternatives are analyzed in a Conservation Potential Assessment and Demand Response Assessment (CPA) to develop a supply curve that is used as an input to the portfolio analysis. The portfolio analysis then determines the maximum amount of energy savings that can be captured without raising the overall electric or natural gas portfolio cost. This identifies the cost-effective level of DSR to include in the portfolio.

PSE included the following demand-side resource alternatives in the CPA that was performed by The Cadmus Group for this IRP.

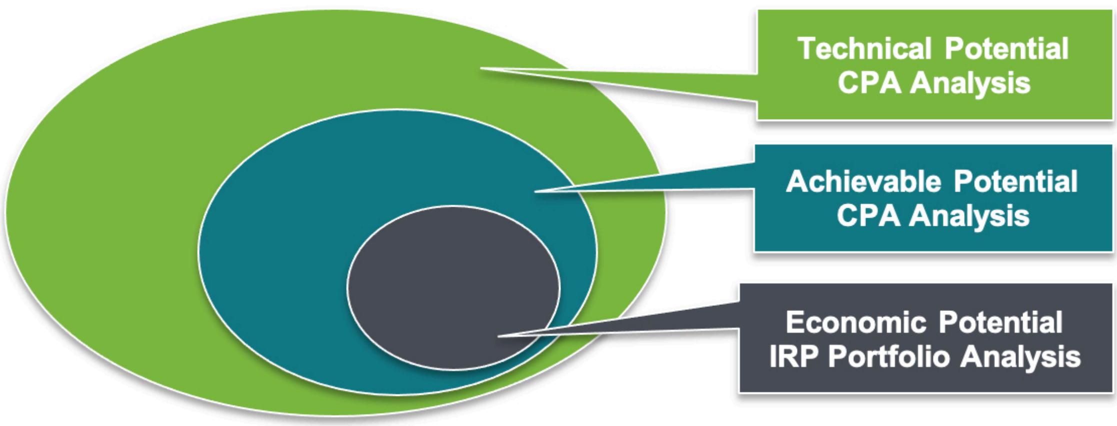
- **ENERGY EFFICIENCY MEASURES.** This label is used for a wide variety of measures that result in a smaller amount of energy being used to do a given amount of work. These include retrofitting programs such as heating, ventilation and air conditioning (HVAC) improvements, building shell weatherization, lighting upgrades and appliance upgrades.
- **DEMAND RESPONSE (DR).** Demand response resources are comprised of flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost.
- **DISTRIBUTED GENERATION.** Distributed generation refers to small-scale electricity generators located close to the source of the customer's load on customer's side of the utility meter. This includes combined heat and power (CHP) and rooftop solar.[19]
- **DISTRIBUTION EFFICIENCY (DE**). This involves conservation voltage reduction (CVR) and phase balancing. Voltage reduction is the practice of reducing the voltage on distribution circuits to reduce energy consumption, as many appliances and motors can perform properly while consuming less energy. Phase balancing eliminates total current flow energy losses.
- **GENERATION EFFICIENCY.** This involves energy efficiency improvements at the facilities that house PSE generating plant equipment, and where the loads that serve the facility itself are drawn directly from the generator and not the grid. These loads are also called parasitic loads. Typical measures target HVAC, lighting, plug loads and building envelope end-uses.
- **CODES AND STANDARDS (C&S).** These are no-cost energy efficiency measures that work their way to the market via new efficiency standards set by federal and state codes and standards. Only those that are in place at the time of the CPA study are included.

19 / In this IRP distributed solar PV is not included in the demand-side resources. Instead, it is handled as a direct no-cost reduction to the customer load. Solar PV subsidies are driving implementation and the subsidies are not fully captured with by the Total Resource Cost (TRC) approach that is used to determine the cost-effectiveness of DSR measures. Under the TRC approach, distributed solar PV is not cost effective and so is not selected in the portfolio analysis. Treating solar as a no-cost load reduction captures the adoption of this distributed generation resource by customers and its impact on loads more accurately.

Treatment of Demand-side Resource Alternatives

The conservation potential assessment performed for PSE by The Cadmus Group develops two levels of demand-side resource potential: technical potential and achievable technical potential. The IRP portfolio analysis then identifies the third level, economic potential. Figure D-15 shows the relationship between the technical, achievable and economic conservation potentials.

Figure D-15: Relationship between Technical, Achievable and Economic Potential



First, the CPA screened each measure for technical potential. This screen assumed all energy- and demand-saving opportunities could be captured regardless of cost or market barriers, which ensured the full spectrum of technologies, load impacts and markets were surveyed.

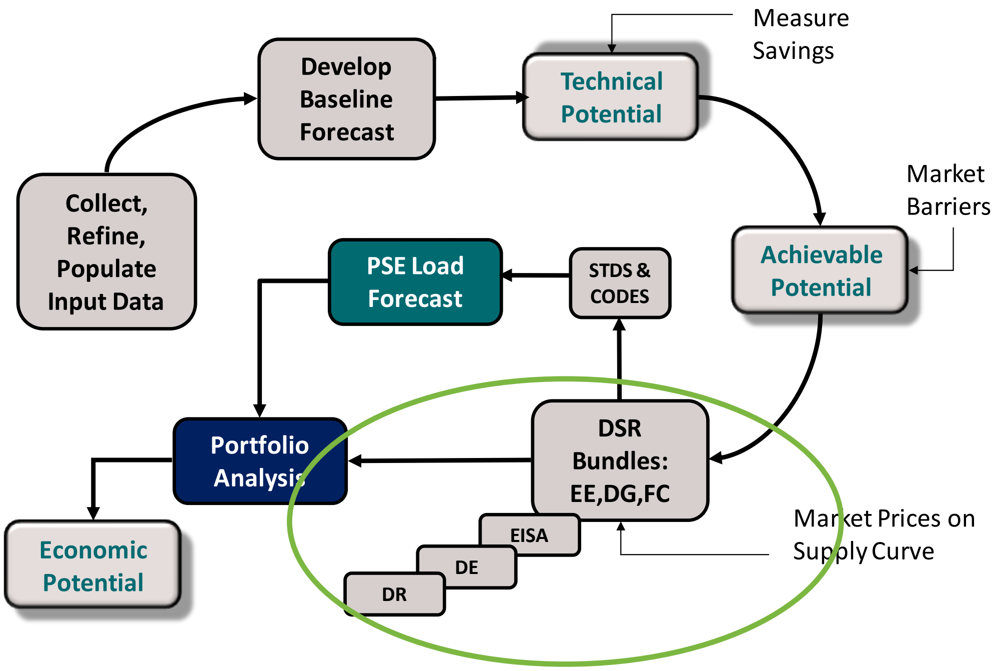
Second, market constraints were applied to estimate the achievable potential. To gauge achievability, Cadmus relied on customer response to past PSE energy programs, the experience of other utilities offering similar programs, and the Northwest Power and Conservation Council's most recent energy efficiency potential assessment. For this IRP, PSE assumed achievable electric energy efficiency potentials of 85 percent in existing buildings and 65 percent in new construction.

In the third step, the measures were combined into bundles based on levelized cost. This produces a conservation supply cost curve that is included in the IRP portfolio optimization analysis to identify the economic potential (cost-effectiveness) of the bundles.

Figure D-16 illustrates the methodology PSE used to assess demand-side resource potential in the IRP.

>>> See Appendix E, Conservation Potential Assessment and Demand Response Assessment, to access the Cadmus report.

Figure D-16: General Methodology for Assessing Demand-side Resource Potential

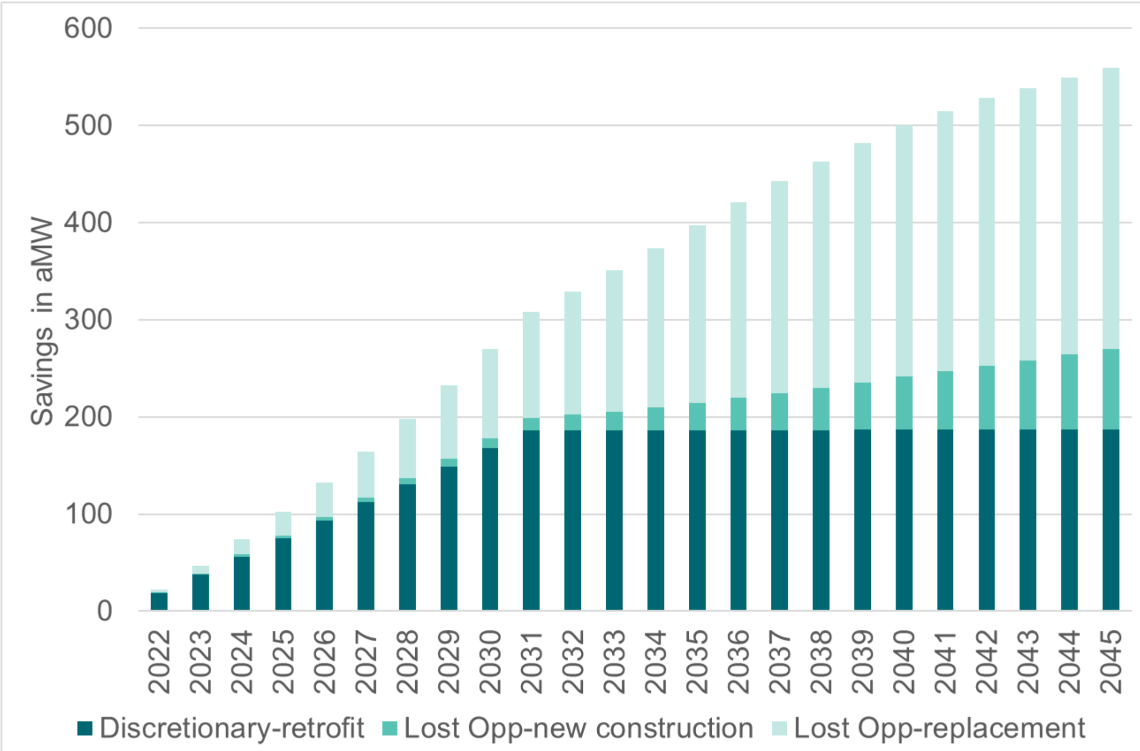


The tables and charts that follow summarize the results of the Cadmus Group's analysis of demand-side resources. Bundles 1 through 13 include energy efficiency and distributed generation. Each bundle adds measures to the bundle that preceded it. For a discussion of distribution efficiency (DE) bundles, see the section below. For the discussion of the Codes and Standards (C&S) bundles, see Appendix E, Conservation Potential Assessment report.

The savings potential for Bundles 1 through 13 consists of both retrofit and lost opportunity measures.[20] Figure D-17 shows the proportion of discretionary versus lost opportunity measures in the bundles.

20 /According to the Regional Technical Form: Lost opportunity measures are those that are available only during a specific window of time at a cost specific to the circumstances surrounding that instance of implementation, for example the replacement of equipment on failure of equipment or the addition of new equipment or facilities. Similarly, retrofit measures, also known as discretionary measures, are improvements to or replacements of systems that do not need to occur at the time of actual improvement or replacement.

Figure D-17: Discretionary versus Lost Opportunity Measures in Bundles 1 to 13



Distribution Efficiency

Plans for distribution efficiency have been updated in this IRP to reflect the changes in technology required to maintain power quality and stability as the role of distribution efficiency grows, while at the same time increasing amounts of distributed generation are entering the delivery system.

The original conservation voltage reduction (CVR) program PSE implemented in 2012-2013 utilized AMI meters that are now outdated and incompatible with the company-wide rollout of upgraded AMI technology that began in 2018. That rollout is expected to be completed in 2023. In the meantime, selected substations that have received the AMI upgrade will be able to participate in the current CVR program.

A second technology upgrade is planned as well. The current CVR program is a static form of CVR that cannot react to compensate for changes on the distribution system produced by distributed resources such as battery storage, solar generation and DR schemes. Because the static system cannot react and adjust to changing conditions on the distribution system, PSE is therefore investing in Automated Distribution Management System (ADMS) technology that can be programmed to automatically detect and anticipate changing conditions on the system. This will enable the system to react fast enough to prevent putting customers' power quality at risk.

Once the AMI and ADMS technologies are fully implemented, PSE will also have the operational control system necessary to transition the CVR program to full Volt-Var Optimization (VVO). ADMS will leverage AMI data at the end of line, with its own analytics and control intelligence to dynamically optimize power delivery within the distribution network, minimize losses and conserve energy. This builds upon dynamic voltage control by sensing and managing switched capacitors to optimize the power factor. VVO is a more sophisticated and extensive process than CVR, but relies on similar principles.

Completion of the AMI rollout is expected in 2023, and the ADMS software platform is expected to be completed in 2021. PSE expects to begin piloting VVO in 2021. From 2019-2021, we will continue implementing the current, static line drop compensation (LDC) CVR, but we expect we may continue to encounter complications and risks due to changes on the distribution system that are already occurring.

Eligible Substations. The current CVR program was put into place based on a study completed in 2007. According to that study, approximately 150 substations with at least 50 percent residential customers were identified as having the potential for energy savings using LDC CVR, based on typical customer usage patterns and the customer composition of the substations. Those 150 substations represented 52 percent of PSE's total 297 distribution substations and affected 67 percent of the PSE's customers.

An updated study is needed to confirm the number of substations which have the potential for cost-effective energy saving VVO. The implementation schedule and associated energy savings in Figures D-18 and D-19 below outline a projected number of substations to be completed each year and the cumulative savings expected.

Figure D-18: Implementation Schedule for Eligible Substations

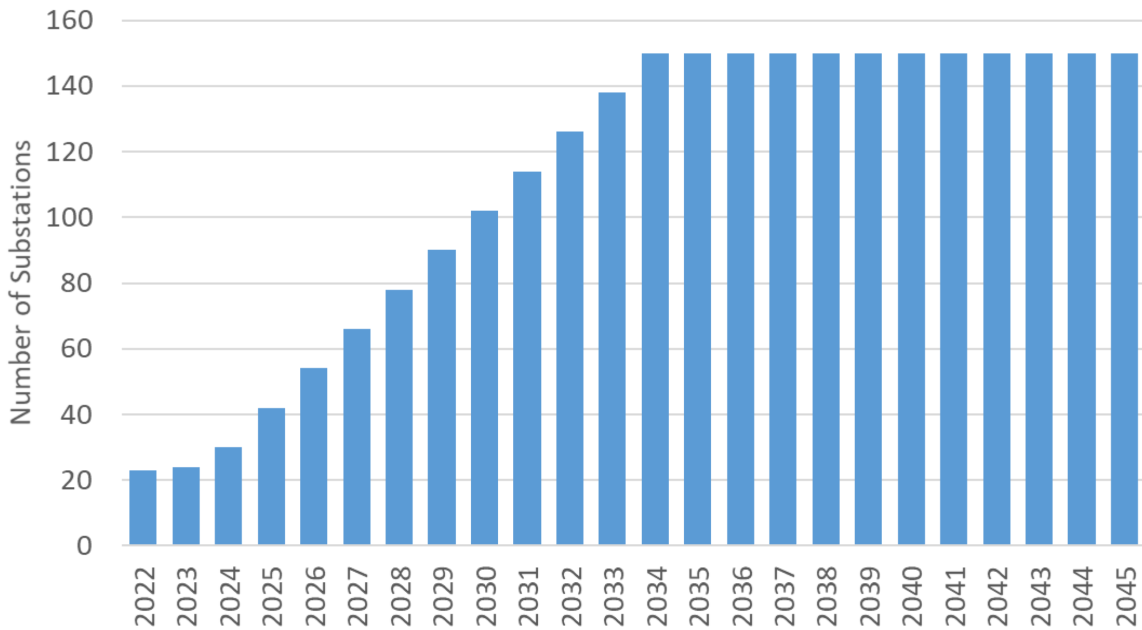


Figure D-19: Cumulative Savings in aMW from Distribution Efficiency (CVR+VVO)

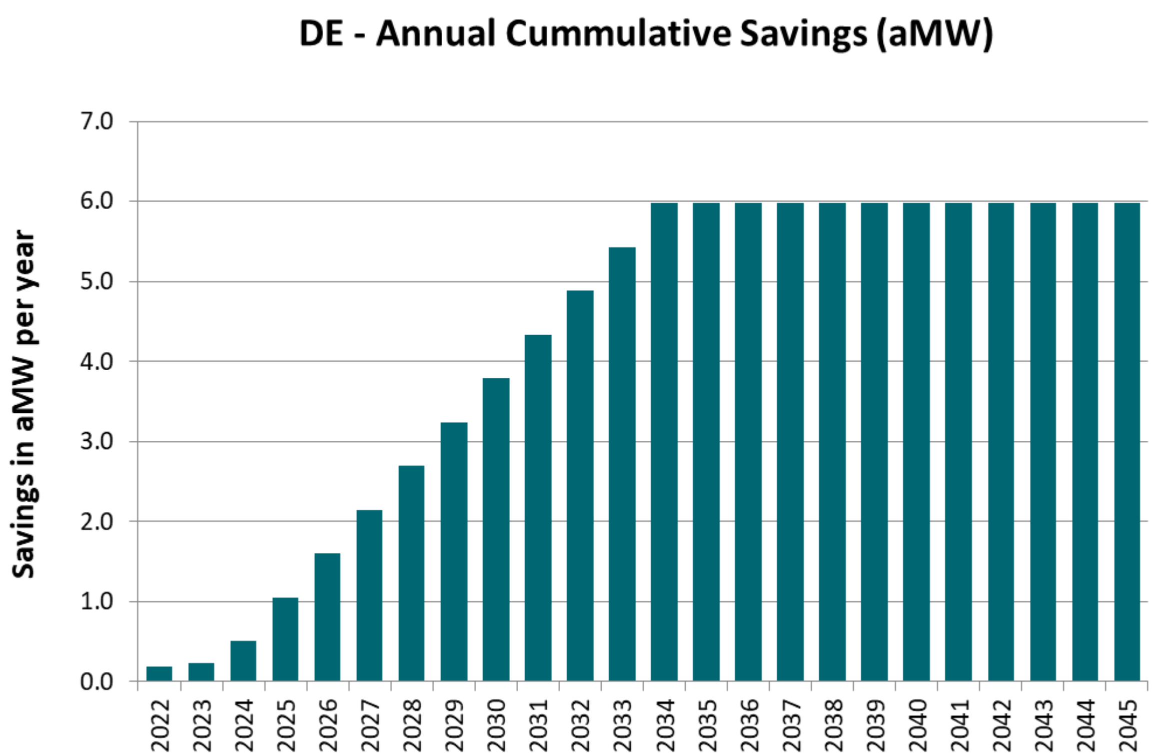


Figure D-20: Annual Energy Savings (aMW

	Bundles (aMW)														
	1	2	3	4	5	6	7	8	9	10	11	12	13	DE	C&S
2022	3.7	1.8	1.2	0.2	0.5	0.2	0.6	0.5	1.2	0.2	0.1	0.1	1.3	0.5	21.8
2023	11.8	5.8	3.6	0.8	1.6	0.6	2.1	1.6	3.8	0.7	0.4	0.3	4.1	1.1	33.1
2024	20.4	10.0	6.2	1.4	2.7	1.0	3.8	3.1	6.9	1.4	0.7	0.5	7.2	1.7	44.8
2025	29.2	14.4	8.7	2.3	3.8	1.4	5.7	4.6	10.2	2.3	1.0	0.8	10.6	3.0	53.3
2026	38.3	18.8	11.2	3.3	4.9	1.7	7.9	6.2	13.7	3.4	1.5	1.0	14.4	4.3	60.5
2027	47.7	23.5	13.7	4.5	6.1	2.1	10.4	8.0	17.3	4.7	2.0	1.3	18.5	5.7	67.4
2028	57.6	28.6	16.2	6.0	7.4	2.5	13.2	10.0	21.0	6.3	2.7	1.6	23.2	7.0	73.9
2029	67.3	33.5	18.7	7.7	8.7	2.9	16.2	11.9	24.7	8.1	3.4	1.8	28.1	8.3	80.1
2030	77.2	38.6	21.2	9.6	10.0	3.3	19.3	13.9	28.4	10.3	4.2	2.2	33.5	9.6	86.5
2031	87.5	43.8	23.7	11.8	11.4	3.7	22.7	16.2	32.2	12.9	5.2	2.5	39.3	10.9	93.4
2032	95.0	47.5	25.2	14.0	12.4	4.0	25.9	18.3	35.4	15.8	6.1	2.8	44.4	12.2	99.1
2033	98.6	49.1	25.2	16.2	12.8	4.0	28.3	19.8	37.6	18.9	6.9	3.0	48.2	13.5	104.2
2034	102.6	50.8	25.3	18.5	13.3	4.1	31.0	21.5	39.9	22.3	7.8	3.3	52.4	14.8	110.3
2035	106.7	52.7	25.4	20.7	13.9	4.1	33.7	23.5	42.3	26.0	8.7	3.5	56.7	14.8	117.1
2036	111.0	54.7	25.6	23.0	14.5	4.2	36.7	25.6	44.8	30.0	9.7	3.8	61.2	14.8	123.0
2037	114.7	56.2	25.6	25.2	15.0	4.3	39.3	27.3	46.9	34.0	10.6	4.1	65.4	14.8	128.7
2038	118.7	57.6	25.7	27.4	15.6	4.3	42.0	28.6	48.1	37.9	11.5	4.3	69.4	14.8	134.4
2039	122.8	59.0	25.7	29.6	16.2	4.4	44.7	29.6	48.6	41.8	12.3	4.6	73.1	14.8	140.3
2040	126.9	60.5	25.8	31.6	16.8	4.5	47.3	30.8	49.2	45.8	13.2	4.9	76.8	14.8	145.9
2041	129.6	61.6	25.8	32.4	17.3	4.5	49.1	31.7	49.4	49.5	14.0	5.1	79.9	14.8	151.7
2042	132.6	62.8	25.9	32.6	17.9	4.6	50.5	32.7	49.7	53.2	14.7	5.4	82.8	14.8	157.4
2043	135.6	64.1	25.9	32.7	18.5	4.6	51.7	33.7	49.9	56.3	15.0	5.6	84.5	14.8	163.0
2044	139.1	65.6	26.0	32.9	19.1	4.7	53.1	34.9	50.3	59.1	15.1	5.9	85.8	14.8	168.4
2045	141.7	66.6	25.9	32.9	19.6	4.8	54.1	35.9	50.4	61.4	15.1	6.1	86.4	14.8	174.1

Figure D-21: Total December Peak Reduction (MW

	Bundles (MW)														
	1	2	3	4	5	6	7	8	9	10	11	12	13	DE	C&S
2022	12.1	7.2	3.7	0.7	2.7	0.9	2.7	1.3	4.1	0.6	0.5	0.3	5.3	1.2	37.0
2023	24.8	14.7	7.3	1.5	5.4	1.7	5.7	3.0	8.6	1.6	1.1	0.7	11.2	1.5	61.4
2024	38.0	22.5	11.0	2.6	8.1	2.6	9.1	4.8	13.4	2.9	2.0	1.0	17.6	2.2	80.2
2025	51.6	30.4	14.7	4.0	10.9	3.4	12.7	6.7	18.4	4.7	3.0	1.4	24.9	3.9	92.1
2026	65.6	38.5	18.4	5.6	13.7	4.2	16.7	8.7	23.5	6.8	4.2	1.7	32.9	5.1	107.0
2027	80.2	47.0	22.1	7.5	16.7	5.1	21.2	10.8	28.7	9.6	5.7	2.1	42.0	6.4	120.9
2028	95.2	55.8	25.8	9.8	19.7	6.0	26.0	13.2	34.0	13.0	7.4	2.5	52.0	7.7	145.6
2029	110.3	64.5	29.5	12.4	22.7	6.8	31.0	15.4	39.3	17.1	9.4	2.9	62.8	8.9	158.9
2030	126.0	73.5	33.2	15.4	25.8	7.6	36.3	17.9	44.7	22.0	11.7	3.3	74.7	10.2	163.0
2031	142.1	82.6	36.9	18.6	29.1	8.5	41.9	20.5	50.1	27.6	14.1	3.7	87.4	11.5	168.7
2032	147.8	85.3	37.0	21.8	29.9	8.5	45.5	22.3	52.5	33.6	16.5	3.9	96.2	12.8	180.6
2033	153.9	87.7	37.1	25.0	30.6	8.6	48.9	23.8	54.8	40.4	18.9	4.2	105.4	14.1	199.0
2034	160.5	90.6	37.3	28.4	31.5	8.6	52.7	25.8	57.2	47.7	21.3	4.5	115.0	15.4	222.2
2035	166.8	93.3	37.5	31.5	32.3	8.7	56.5	27.9	59.6	55.4	23.8	4.8	124.5	14.6	236.9
2036	173.0	95.8	37.7	34.7	33.2	8.7	60.2	30.0	62.0	63.5	26.2	5.0	134.1	14.6	224.7
2037	179.3	98.1	37.7	37.9	34.1	8.8	63.8	31.6	64.1	71.7	28.7	5.3	143.8	14.6	236.9
2038	185.8	100.3	37.7	41.2	35.1	8.9	67.6	32.8	64.8	79.8	31.2	5.6	153.0	14.6	248.3
2039	192.5	102.4	37.8	44.4	36.1	8.9	71.2	34.0	65.5	88.1	33.5	5.8	161.6	14.6	271.2
2040	198.1	104.3	37.9	46.7	36.9	9.0	74.4	35.3	66.1	96.3	35.8	6.1	169.9	14.6	296.2
2041	203.3	106.2	37.9	47.2	37.9	9.0	76.6	36.4	66.5	104.7	38.2	6.4	177.8	14.6	292.8
2042	208.3	108.1	37.9	47.5	38.8	9.1	78.5	37.6	66.8	112.2	40.0	6.6	183.7	14.6	290.3
2043	213.3	110.1	38.0	47.6	39.5	9.2	80.1	38.8	67.2	116.6	40.0	6.9	184.9	14.6	302.1
2044	218.7	112.3	38.0	47.8	40.4	9.3	81.9	40.2	67.7	121.2	40.2	7.2	186.7	14.6	325.8
2045	223.7	114.1	38.0	47.9	41.2	9.3	83.5	41.4	68.1	125.6	40.2	7.4	188.0	14.6	354.1

The DSR December peak reduction is based on the average of the very heavy load hours (VHLH). The VHLH method takes the average of the five-hour morning peak from hour ending 7 a.m. to hour ending 11 a.m. and the five-hour evening peak from hour ending 6 p.m. to hour ending 10 p.m. Monday through Friday. The system demand peaked during the evening hours and correspondingly the demand-side resource peaks were chosen to be coincident with those evening system peak hours.

Figure D-22: Annual Costs (dollars in thousands)
(Codes and Standards has no cost and is considered a must-take bundle.)

	Bundles ($'000)													
	1	2	3	4	5	6	7	8	9	10	11	12	13	DE
2022	$3,892	$14,579	$13,849	$2,855	$7,341	$2,949	$12,265	$11,739	$32,508	$6,044	$3,789	$4,260	$253,744	$2,450
2023	$4,456	$16,015	$13,875	$3,744	$7,573	$3,032	$15,121	$15,469	$38,664	$8,988	$4,867	$4,436	$263,266	$2,700
2024	$4,313	$16,818	$13,891	$4,603	$7,797	$3,034	$17,609	$17,750	$42,756	$11,803	$5,940	$4,623	$272,897	$3,270
2025	$4,449	$16,870	$13,892	$5,673	$7,969	$2,921	$19,528	$17,875	$45,311	$14,627	$7,317	$4,771	$283,391	$5,490
2026	$4,718	$17,775	$13,905	$6,779	$8,263	$2,966	$22,357	$19,702	$47,244	$17,658	$8,691	$5,024	$295,726	$6,090
2027	$5,052	$18,637	$13,918	$8,148	$8,610	$3,014	$25,215	$21,434	$48,468	$21,677	$10,355	$5,327	$310,353	$6,690
2028	$5,404	$19,548	$13,925	$9,661	$8,995	$3,093	$27,962	$23,623	$49,350	$25,827	$12,128	$5,696	$325,699	$7,290
2029	$5,570	$19,178	$13,911	$11,033	$9,180	$2,961	$28,866	$21,403	$49,538	$30,455	$13,887	$5,822	$337,674	$7,890
2030	$6,054	$20,295	$13,913	$12,570	$9,649	$3,094	$31,667	$24,708	$50,292	$35,746	$15,620	$6,271	$354,541	$8,490
2031	$6,483	$20,106	$13,902	$13,799	$10,025	$3,160	$33,625	$26,678	$50,788	$40,908	$17,023	$6,612	$368,456	$9,090
2032	$3,187	$6,840	$629	$13,117	$3,267	$418	$24,695	$19,903	$31,880	$44,259	$15,151	$4,948	$137,645	$9,690
2033	$3,260	$5,999	$630	$13,595	$3,207	$247	$23,882	$15,919	$31,569	$48,716	$15,828	$4,703	$140,718	$10,290
2034	$3,968	$7,510	$674	$13,933	$3,733	$493	$26,666	$22,065	$32,414	$53,435	$16,284	$5,210	$153,873	$10,890
2035	$4,333	$7,471	$692	$13,489	$3,971	$576	$27,421	$24,135	$32,703	$56,968	$16,418	$5,341	$159,132	$7,650
2036	$4,490	$6,827	$693	$13,401	$3,958	$513	$27,007	$22,734	$32,506	$59,827	$16,407	$5,190	$159,094	$7,650
2037	$4,409	$6,042	$303	$13,237	$3,778	$367	$25,713	$17,088	$27,103	$60,962	$16,381	$4,885	$155,776	$7,650
2038	$4,682	$5,429	$214	$13,290	$3,956	$461	$26,376	$10,793	$6,096	$56,491	$15,508	$5,043	$134,395	$7,650
2039	$4,830	$5,239	$213	$13,288	$4,049	$505	$25,532	$11,995	$6,279	$57,191	$15,145	$5,105	$126,308	$7,650
2040	$4,919	$5,414	$212	$9,910	$4,104	$534	$22,761	$12,723	$6,389	$57,704	$15,116	$5,139	$127,299	$7,650
2041	$4,776	$4,822	$199	$1,270	$3,952	$433	$15,285	$10,004	$3,298	$57,974	$15,083	$4,918	$119,554	$7,650
2042	$4,865	$5,146	$207	$1,102	$4,033	$495	$13,272	$11,597	$3,173	$54,249	$11,749	$5,014	$102,142	$7,650
2043	$4,858	$5,030	$208	$449	$3,628	$503	$12,019	$11,816	$3,190	$37,667	$228	$5,007	$53,941	$7,650
2044	$4,955	$5,283	$217	$511	$3,676	$571	$12,613	$13,565	$3,394	$36,919	$39	$5,116	$55,811	$7,650
2045	$4,745	$4,650	$202	$421	$3,508	$473	$11,623	$11,040	$3,079	$36,600	$36	$4,901	$51,404	$7,650

Demand Response

Demand response (DR) is a strategy designed to decrease load on the grid during times of peak use. It involves modifying the way customers use energy – particularly when they use it. For instance, businesses might work with PSE to voluntarily adjust their operations during a specified time range. Residential customers might automate their usage with smart thermostats or water heaters. While there are often financial incentives to participate in DR pilots and programs, it is also a way for both PSE and customers to increase efficiency and reduce their carbon footprints.

Demand response programs are voluntary, and once enrolled, customers usually receive notifications in advance of forecasted peak usage times. Depending on the program, this might mean that their thermostat automatically warms their home or building earlier than usual. Because of the remote function of demand response, no action is required from customers to initiate their reduction in load, and they can always choose to opt out of an event.

Demand response programs are organized into four categories. These include:

- Direct Load Control (DLC)
- Commercial and Industrial (C&I) Curtailment
- Dynamic Pricing or Critical Peak Pricing (CPP)
- Behavioral DR

Figures D-23a and 23b provide the total winter and summer peak reduction potential for each program, and Figures D-24a and 24b show the costs for each of those programs. In these tables, the numbers across the top represent the 16 different DR programs analyzed, as follows:

1. Residential CPP-No Enablement
2. Residential CPP-With Enablement
3. Residential DLC Heat-Switch
4. Residential DLC Heat-BYOT
5. Residential DLC ERWH-Switch
6. Residential DLC ERWH-Grid-Enabled
7. Residential DLC HPWH-Switch
8. Residential DLC HPWH-Grid-Enabled
9. Small Commercial DLC Heat-Switch
10. Medium Commercial DLC Heat-Switch
11. Commercial & Industrial Curtailment-Manual
12. Commercial & Industrial Curtailment-AutoDR
13. Commercial CPP-No Enablement
14. Commercial CPP-With Enablement
15. Residential EV DLC
16. Residential Behavior DR

Figure D-23a: Demand Response Programs, Total Winter Peak Reduction (MW)

DR Winter Programs (MW)																
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	4	0	5	1	0	0	1	0	0	0	0	0	0	1
2024	0	0	8	0	9	2	0	0	1	1	0	0	0	0	0	3
2025	5	0	16	0	18	5	0	0	2	2	1	1	0	0	1	4
2026	10	0	25	1	25	10	0	0	3	3	1	1	1	0	1	5
2027	20	1	34	1	31	16	0	0	5	3	2	2	1	1	2	7
2028	30	1	42	1	35	24	1	0	6	4	2	2	1	1	2	7
2029	41	1	43	2	32	27	0	0	6	4	2	2	1	1	2	7
2030	52	2	43	2	29	31	0	0	6	4	2	3	1	1	3	7
2031	53	2	44	2	25	35	0	1	6	5	2	3	1	1	3	7
2032	54	2	44	3	22	39	0	1	6	5	3	3	1	1	3	7
2033	54	2	45	3	18	43	0	1	6	5	3	3	1	1	4	7
2034	55	2	45	3	15	47	0	1	6	5	3	3	1	1	4	7
2035	56	2	46	3	11	51	0	1	6	5	3	3	1	1	4	8
2036	57	2	46	3	10	53	0	1	6	5	3	3	1	1	5	8
2037	58	2	47	3	10	54	0	1	6	5	3	3	1	1	5	8
2038	59	2	47	3	10	54	0	1	6	5	3	3	1	1	6	8
2039	60	2	48	3	10	55	0	1	6	5	3	3	1	1	6	8
2040	60	2	48	3	10	55	0	1	6	5	3	3	1	1	6	8
2041	61	2	48	3	10	56	0	1	6	5	3	3	1	1	7	8
2042	62	2	49	3	10	56	0	1	6	5	3	3	1	1	7	8
2043	63	2	49	3	10	57	0	1	7	5	3	3	1	1	8	9
2044	64	2	50	3	11	57	0	1	7	5	3	3	1	1	8	9
2045	64	2	50	3	11	58	0	1	7	5	3	3	1	1	9	9

Figure D-23b: Demand Response Programs, Total Summer Peak Reduction (MW)

DR Summer Programs (MW)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	2	0	5	1	0	0	1	1	0	0	0	0	0	1
2024	0	0	4	2	9	2	0	0	1	3	1	1	0	0	0	2
2025	3	0	8	3	18	5	0	0	3	6	1	1	1	1	1	2
2026	6	0	12	6	25	10	0	0	4	9	2	2	1	1	1	3
2027	12	0	16	11	31	16	0	0	6	12	2	3	1	2	2	4
2028	19	0	20	14	35	24	1	0	8	16	3	3	1	3	2	4
2029	25	1	20	17	32	27	0	0	8	16	3	3	1	3	2	4
2030	32	1	21	20	29	31	0	0	8	16	3	3	1	3	3	4
2031	32	1	21	22	25	35	0	1	8	16	3	3	1	3	3	4
2032	33	1	21	24	22	39	0	1	8	16	3	3	1	3	3	4
2033	33	1	21	26	18	43	0	1	8	16	3	3	1	3	4	5
2034	34	1	22	27	15	47	0	1	8	17	3	3	2	3	4	5
2035	34	1	22	28	11	51	0	1	8	17	3	3	2	3	4	5
2036	35	1	22	28	10	53	0	1	8	17	3	3	2	3	5	5
2037	35	1	22	29	10	54	0	1	8	17	3	4	2	3	5	5
2038	36	1	22	29	10	54	0	1	8	17	3	4	2	3	6	5
2039	36	1	23	29	10	55	0	1	8	17	4	4	2	3	6	5
2040	37	1	23	30	10	55	0	1	8	18	4	4	2	3	6	5
2041	37	1	23	30	10	56	0	1	8	18	4	4	2	3	7	5
2042	38	1	23	30	10	56	0	1	9	18	4	4	2	3	7	5
2043	38	1	24	31	10	57	0	1	9	18	4	4	2	3	8	5
2044	39	1	24	31	11	57	0	1	9	18	4	4	2	3	8	5
2045	39	1	24	31	11	58	0	1	9	18	4	4	2	3	9	5

Figure D-24a: Winter Demand Response Annual Costs (dollars in thousands)

	DR Winter Bundles ($'000)															
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
2022	$219	$6	$141	$9	$23	$125	$0	$2	$85	$65	$74	$76	$131	$94	$300	$150
2023	$75	$2	$1,016	$4	$3,379	$103	$127	$4	$155	$65	$19	$95	$74	$49	$336	$88
2024	$77	$2	$1,273	$12	$3,504	$261	$132	$10	$185	$78	$39	$119	$77	$51	$454	$183
2025	$515	$9	$2,641	$26	$6,715	$706	$252	$27	$382	$160	$81	$245	$111	$70	$613	$285
2026	$539	$9	$3,210	$47	$6,758	$1,198	$254	$45	$448	$188	$125	$297	$115	$73	$804	$396
2027	$1,032	$16	$3,816	$78	$6,648	$1,817	$250	$68	$517	$217	$173	$353	$119	$75	$1,041	$514
2028	$1,080	$17	$4,460	$95	$6,372	$2,576	$239	$97	$590	$248	$223	$414	$123	$78	$789	$534
2029	$1,129	$18	$2,621	$117	$2,027	$2,393	$76	$90	$287	$121	$231	$245	$55	$39	$864	$555
2030	$1,181	$19	$2,715	$139	$1,863	$2,737	$70	$103	$297	$126	$239	$257	$57	$40	$972	$576
2031	$150	$3	$2,813	$159	$1,684	$3,102	$63	$117	$308	$130	$249	$271	$58	$41	$1,053	$600
2032	$154	$4	$2,913	$176	$1,490	$3,489	$56	$131	$318	$135	$258	$272	$60	$42	$1,137	$624
2033	$157	$4	$3,015	$190	$1,279	$3,900	$48	$147	$329	$139	$265	$278	$61	$43	$1,225	$648
2034	$161	$4	$3,122	$201	$1,050	$4,334	$39	$163	$340	$144	$276	$298	$63	$44	$1,319	$673
2035	$165	$4	$3,231	$210	$804	$4,794	$30	$180	$351	$149	$288	$315	$64	$46	$1,420	$701
2036	$168	$4	$3,343	$218	$735	$4,684	$28	$176	$363	$154	$298	$319	$66	$47	$1,529	$730
2037	$171	$4	$3,457	$226	$1,252	$4,648	$47	$175	$375	$159	$309	$329	$67	$48	$1,645	$760
2038	$175	$4	$3,575	$234	$1,294	$4,809	$49	$181	$388	$164	$320	$343	$69	$49	$1,767	$790
2039	$179	$4	$3,697	$243	$1,337	$4,974	$50	$187	$401	$169	$333	$359	$71	$50	$1,894	$822
2040	$183	$4	$3,823	$251	$1,382	$5,145	$52	$193	$414	$175	$345	$370	$72	$52	$2,065	$854
2041	$187	$4	$3,952	$260	$1,428	$5,321	$54	$200	$428	$181	$358	$386	$74	$53	$2,201	$889
2042	$191	$4	$4,086	$269	$1,476	$5,502	$55	$207	$442	$187	$372	$400	$76	$54	$2,337	$924
2043	$195	$5	$4,223	$279	$1,525	$5,689	$57	$214	$456	$193	$386	$416	$78	$55	$2,473	$959
2044	$200	$5	$4,364	$289	$1,575	$5,881	$59	$221	$471	$199	$401	$432	$80	$57	$2,606	$994
2045	$204	$5	$4,510	$299	$1,628	$6,079	$61	$228	$487	$206	$417	$451	$82	$58	$2,737	$1,032

Figure D-24b: Summer Demand Response Annual Costs (dollars in thousands)

	DR Summer Bundles ($'000)															
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
2022	$220	$5	$65	$85	$23	$125	$0	$2	$48	$102	$74	$76	$81	$144	$300	$150
2023	$75	$2	$984	$37	$3,379	$103	$127	$4	$347	$173	$24	$122	$57	$88	$336	$54
2024	$77	$2	$1,233	$117	$3,504	$261	$132	$10	$414	$207	$50	$153	$59	$91	$454	$111
2025	$516	$8	$2,557	$251	$6,715	$706	$252	$27	$857	$428	$104	$316	$93	$136	$613	$174
2026	$539	$8	$3,108	$456	$6,758	$1,198	$254	$45	$1,003	$501	$161	$382	$96	$141	$804	$241
2027	$1,033	$16	$3,695	$756	$6,648	$1,817	$250	$68	$1,159	$579	$222	$455	$100	$146	$1,041	$314
2028	$1,081	$16	$4,319	$912	$6,372	$2,576	$239	$97	$1,323	$662	$288	$533	$104	$151	$789	$326
2029	$1,130	$17	$2,537	$1,129	$2,027	$2,393	$76	$90	$644	$324	$297	$315	$36	$62	$864	$338
2030	$1,181	$18	$2,629	$1,342	$1,863	$2,737	$70	$103	$666	$335	$309	$332	$36	$63	$972	$352
2031	$151	$3	$2,723	$1,537	$1,684	$3,102	$63	$117	$690	$347	$321	$349	$37	$65	$1,053	$366
2032	$154	$3	$2,820	$1,702	$1,490	$3,489	$56	$131	$713	$359	$332	$351	$38	$66	$1,137	$381
2033	$158	$3	$2,920	$1,835	$1,279	$3,900	$48	$147	$737	$371	$342	$358	$39	$68	$1,225	$395
2034	$162	$3	$3,023	$1,940	$1,050	$4,334	$39	$163	$762	$383	$355	$384	$40	$70	$1,319	$411
2035	$165	$3	$3,129	$2,027	$804	$4,794	$30	$180	$788	$396	$371	$406	$41	$72	$1,420	$428
2036	$169	$3	$3,237	$2,106	$735	$4,684	$28	$176	$814	$410	$384	$412	$42	$73	$1,529	$445
2037	$172	$3	$3,348	$2,183	$1,252	$4,648	$47	$175	$841	$423	$398	$425	$43	$75	$1,645	$464
2038	$176	$3	$3,462	$2,262	$1,294	$4,809	$49	$181	$869	$437	$413	$443	$44	$77	$1,767	$482
2039	$179	$3	$3,580	$2,344	$1,337	$4,974	$50	$187	$898	$452	$429	$463	$45	$79	$1,894	$501
2040	$183	$3	$3,701	$2,428	$1,382	$5,145	$52	$193	$928	$467	$445	$477	$47	$81	$2,065	$521
2041	$188	$3	$3,827	$2,515	$1,428	$5,321	$54	$200	$959	$483	$462	$498	$48	$83	$2,201	$542
2042	$192	$4	$3,956	$2,605	$1,476	$5,502	$55	$207	$991	$498	$479	$516	$49	$85	$2,337	$563
2043	$196	$4	$4,089	$2,697	$1,525	$5,689	$57	$214	$1,023	$515	$498	$536	$50	$87	$2,473	$585
2044	$200	$4	$4,226	$2,792	$1,575	$5,881	$59	$221	$1,057	$532	$517	$557	$51	$89	$2,606	$607
2045	$205	$4	$4,367	$2,890	$1,628	$6,079	$61	$228	$1,091	$549	$537	$582	$53	$91	$2,737	$629

Supply-side Renewable Resource Costs and Technologies

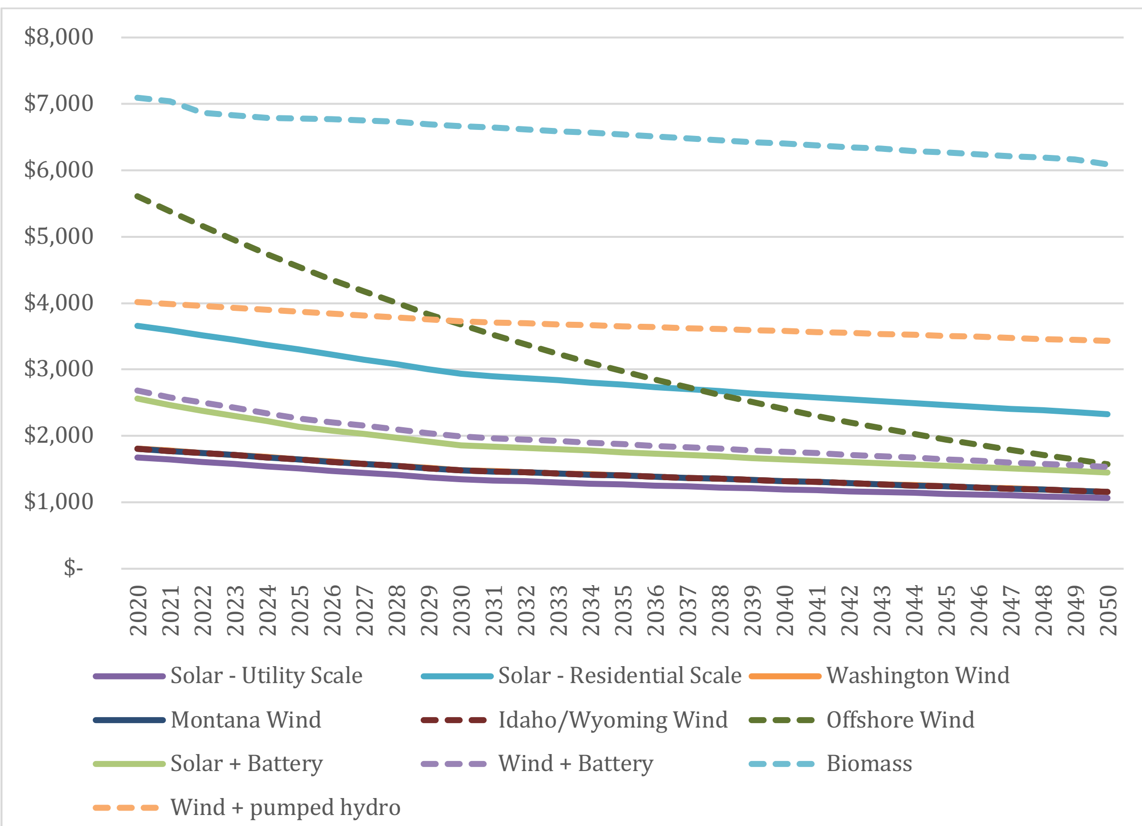
PSE modeled the following supply-side renewable resources in the 2021 IRP:

- biomass
- solar
- wind
- energy storage
- hybrid resources (renewable plus storage)

CAPITAL COST CURVE. Capital costs assumptions start in current the current year, but for future years, the cost curve from the NREL Annual Technology Baseline (ATB) 2019 was applied to the current costs.

Figure D-25 below shows the capital cost curves for the renewable resources modeled in the 2021 IRP.

Figure D-25: Capital Cost Curve for Renewable Resources



Biomass Characteristics

Biomass in this context refers to the burning of woody biomass in boilers. Most existing biomass in the Northwest is tied to steam hosts (also known as "cogeneration" or "combined heat and power"). It is found mostly in the timber, pulp and paper industries. This dynamic has limited the amount of power available to date. The typical plant size we have observed is 10 MW to 50 MW. One major advantage of biomass plants is that they can operate as a baseload resource, since they do not impose generation variability on the grid, unlike wind and solar. Municipal solid waste, landfill and wastewater treatment plant gas are discussed in the section on waste-to-energy technologies in Renewable Resources Not Modeled.

Biomass is modeled in the IRP as a 15 MW, wood-fired facility with a heat rate of 14,599 BTU per kWh. These parameters are intended to reflect a cogeneration facility within proximity to a timber mill.

Commercial Availability. This technology is commercially available. Greenfield development of a new biomass facility requires approximately four years.

Figure D-26: Biomass Generic Resource Assumptions

2020 $	UNITS	BIOMASS
ISO Capacity Primary	MW	15
Capacity Credit	%	0%
Operating Reserves	%	3%
Capacity Factor	%	85%
Capital Cost	$/KW	$7,093
O&M Fixed	$/KW-yr	$207
O&M Variable	$/MWh	$6
Land Area	acres/MW	6 – 8
Degradation	%/year	N/A
Fixed Transmission	$/KW-yr	$22.20
Variable Transmission	$/MWh	$0.00
Loss Factor to PSE	%	1.9%
Heat Rate – Baseload (HHV)	Btu/KWh	14,599
EMISSIONS		
NOx	lbs/MMBtu	0.03
SO2	lbs/MMBtu	0.03
CO2	lbs/MMBtu	213
DEVELOPMENT PARAMETERS		
First Year Available		2024
Economic Life	years	30
Greenfield Dev. & Const. Lead Time	years	3.3

Solar Modeling in the IRP

Solar energy uses electromagnetic radiation from the sun to directly generate electricity with photovoltaic (PV) technology, or to capture the heat energy of the sun for either heating water or for creating steam to drive electric generating turbines. This IRP models two solar PV applications, a utility-scale, single-axis tracking PV technology and a residential fixed-tilt, rooftop-mounted, PV technology.

For the 2021 IRP, PSE has evaluated six solar resources: utility-scale solar PV in eastern Washington, western Washington, eastern Wyoming, western Wyoming, Idaho and residential-scale rooftop-mounted PV solar in western Washington.

Specific solar generation profiles, or shapes, were derived for each of these solar resource types using irradiance data queries from the NREL's National Solar Radiation Database (NSRDB).[21] The NSRDB irradiance data was then processed with NREL's System Advisory Model (SAM)[22] to create realistic generation profiles for each location. SAM inputs were varied depending on the specific solar resource modeled:

- All solar resources were modeled with SAM's implementation of the NREL PVWatts v7.
- All solar resources were modeled with the "premium" module type to estimate solar panel efficiencies of 18 to 20 percent.
- All solar resources were modeled with a DC to AC ratio of 1.2.
- All solar resources assumed an inverter efficiency of 96 percent.
- Residential solar resources were modeled as fixed-tilt, rooftop-mounted panels.
- Utility-scale solar resources were modeled as ground-mounted, single-axis tracking panels.

Figure D-27 provides a summary of the solar resources modeled. All capacity factors are provided as AC (alternating current), where the capacity of the inverter is taken as the nameplate of the solar facility. This differs from the DC (direct current) capacity, which measures the capacity based on the capacity of the solar modules installed. The AC capacity is typically higher, because most solar facilities undersize the inverter as defined by the DC to AC ratio; in the case of PSE generic resources, the DC to AC ratio is 1.2.

After all profiles were processed by SAM, 250 representative draws are selected from the complete list based on nearness to the annual average production of all the solar profiles sampled. Finally a single, most-representative draw is selected from the 250 draws using the same selection process. Figure D-28 provides a summary of the seasonal solar shapes used in

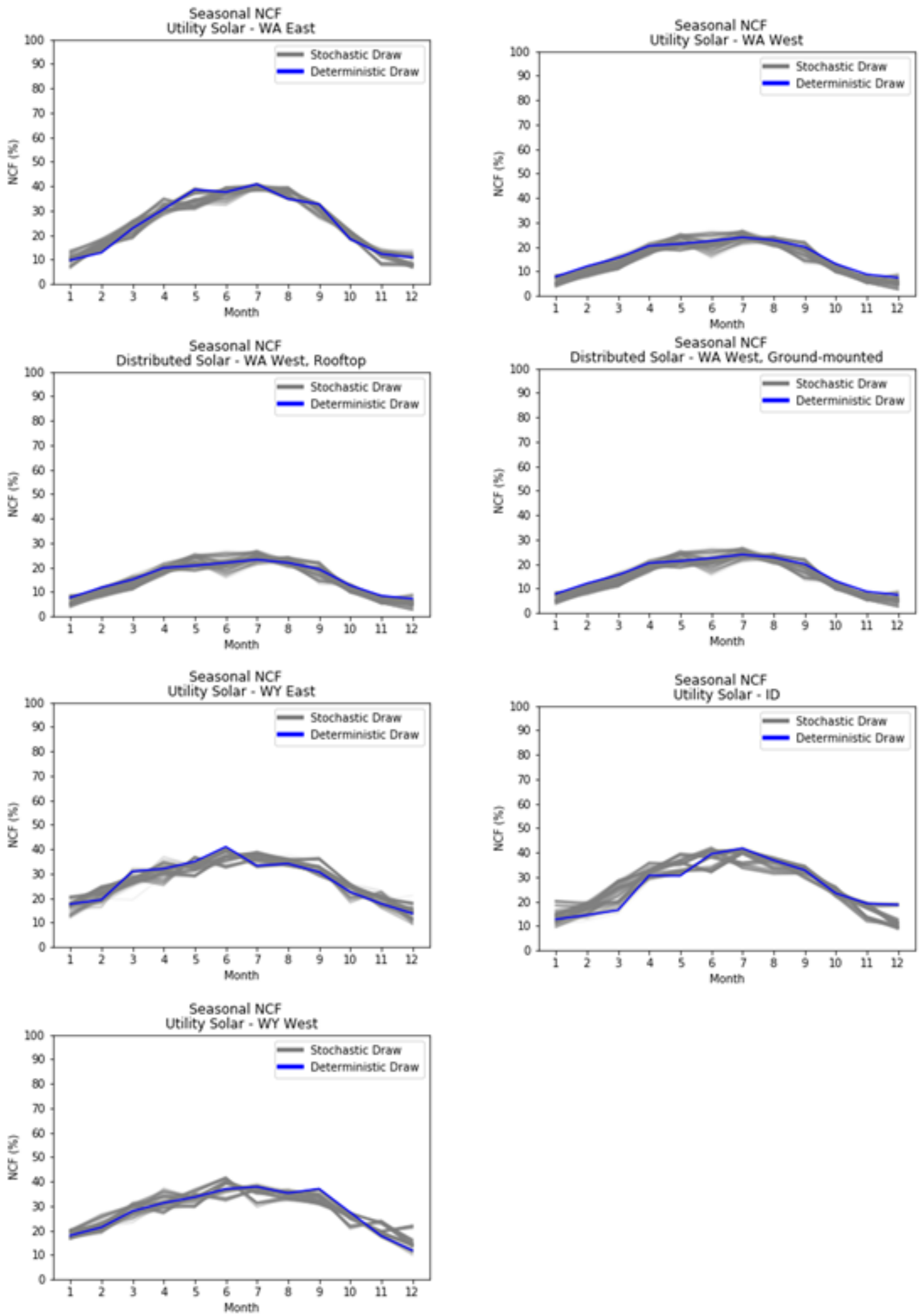
21 / https://nsrdb.nrel.gov/
22 / https://sam.nrel.gov/

the 2021 IRP, the grey lines represent each of the 250 stochastic draws and the blue line represents the draw selected as most-representative.

Figure D-27: Solar Generic Resource Assumptions

2020 $	Units	Utility Solar WA East	Utility Solar WA West	Utility Solar WY West	Utility Solar WY East	Utility Solar ID	Distributed Solar WA West, Rooftop	Distributed Solar WA West, Ground-mounted
ISO Capacity Primary	MW	100	50	400	400	400	300	50
Capacity Credit (2027)	%	4.0%	1.2%	6.0%	6.3%	3.4%	1.6%	1.2%
Operating Reserves	%	3%	3%	3%	3%	3%	3%	3%
Capacity Factor	%	24.2%	16.0%	28.0%	27.3%	26.4%	15.7%	16.0%
Capital Cost	$/KW	$1,675	$1,675	$1,675	$1,675	$1,675	$4,389	$3,568
O&M Fixed	$/KW-yr	$22	$22	$22	$22	$22	$0	$0
O&M Variable	$/MWh	$0	$0	$0	$0	$0	$0	$0
Land Area	acres/MW	5 - 7	5 - 7	5 - 7	5 - 7	5 - 7	N/A	5 - 7
Degradation	%/year	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Fixed Transmission	$/KW-yr	$24.04	$0	$47	$52	$33	$0	$0
Variable Transmission	$/MWh	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Loss Factor to PSE	%	1.9%	N/A	5.0%	5.0%	4.0%	N/A	N/A
DEVELOPMENT PARAMETERS								
First Year Available		2024	2024	2026	2026	2026	2024	2024
Economic Life	Years	30	30	30	30	30	30	30
Greenfield Dev. & Const. Lead Time	years	1.0	1.0	1.0	1.0	1.0	1.0	1.0

Figure D-28: Seasonal Solar Shapes



Solar Technologies

Photovoltaics are semiconductors that generate direct electric currents. The current then typically runs through an inverter to create alternating current, which can be tied into the grid. Most photovoltaic solar cells are made from silicon imprinted with electric contacts; however, other technologies, notably several chemistries of thin-film photovoltaics, have gained substantial market share. Significant ongoing research efforts continue for all photovoltaic technologies, which has helped to increase conversion efficiencies and decrease costs. Photovoltaics are installed in arrays that range from a few watts for sensor or communication applications, up to hundreds of megawatts for utility-scale power generation. PV systems can be installed on a stationary frame at a tilt to best capture the sun (fixed-tilt) or on a frame than can track the sun from sunrise to sunset.

Distributed Solar uses similar technologies to utility-scale photovoltaic systems, but at a smaller scale. The defining characteristic of distributed solar systems is that the power is generated at, or near, the point where the power will be used. This means that distributed solar systems do not have the same costly transmission requirements of utility-scale systems. Distributed solar may include rooftop or ground-mounted systems (such as parking lot canopies).

Concentrating Photovoltaics use lenses to focus the sun's light onto special, high-efficiency photovoltaics, which creates higher amounts of generation for the given photovoltaic cell size. The use of concentrating lenses requires that these technologies be precisely oriented towards the sun, so they typically require active tracking systems.

Bifacial Photovoltaic modules collect light on both sides of the panel, instead of just on the side facing the sun (as in typical PV installations). Bifacial modules can achieve greater efficiencies per unit of land, reducing the land use requirements. Efficiency gains made by bifacial module are highly dependent on the amount of light reflected by the ground surface, or albedo.

Solar Thermal Plants focus the direct irradiance of the sun to generate heat to produce steam, which in turn drives a conventional turbine generator. Two general types are in use or development today, trough-based plants and tower-based plants. Trough plants use horizontally mounted parabolic mirrors or Fresnel mirrors to focus the sun onto a horizontal pipe that carries water or a heat transfer fluid. Tower plants use a field of mirrors that focus sunlight onto a central receiver. A heat transfer fluid is used to collect the heat and transfer it to make steam.

Commercial Availability. Currently, renewable portfolio standards (RPS), falling prices and tax incentives drive most utility-scale solar development in the United States. The Solar Electric Industries Association (SEIA) reports that as of Q3 2020, the U.S. has installed over 85 GW of total solar capacity, with an average annual growth rate of 59 percent over the last ten years.

According to SEIA, solar has ranked first or second in new electric capacity additions in each of the last 7 years. In 2019, 40 percent of all new electric capacity added to the grid came from solar.[23]

With less sunlight than other areas of the country and incentive structures that limit development to smaller systems, photovoltaic development has been relatively slow in the Northwest, and there are no customer or utility-scale concentrating solar thermal installations in Washington state. California continues to be the U.S. leader with nearly 28,000 MW of combined residential, non-residential and utility-scale solar installations as of Q3 2020. While PV installations make up the majority of the installed capacity, the total also includes thermal solar systems, which have been operating successfully in California since the 1980s.[24]

Cost and Performance Assumptions. Since PSE built the Wild Horse Solar Demonstration Project in 2007, installed costs for PV solar systems have declined considerably. SEIA reports that the installed cost of solar has dropped more than 70 percent since 2010, and prices as of Q2 2020 are at or near their lowest historical level across all market segments despite tariffs on modules, inverters, aluminum and steel. According to SEIA's U.S. Solar Market Insight report, by Q2 2020 costs for utility fixed-tilt and tracking projects averaged \$0.81 and \$.95 per Watt_{dc}, respectively; costs for residential systems had reached approximately \$2.84 per Watt_{dc}; and costs for commercial systems had reached \$1.39 per Watt_{dc}.[25]

The locations, technology and average annual capacity factors for each generic solar resource modeled in this IRP are included in Figure D-27.

Wind Modeling in the IRP

Wind energy is the primary renewable resource for meeting RPS and CETA requirements in our region due to wind's technical maturity, reasonable life cycle cost, acceptance in various regulatory jurisdictions and large "utility" scale compared to other technologies. However, it also poses challenges. Because of its variability, wind's daily and hourly power generation shapes don't necessarily correlate with customer demand; therefore, more flexible thermal and hydroelectric resources must be standing by to fill the gaps. This variability also makes wind power challenging to integrate into transmission systems. Finally, because wind projects are often located in remote areas, they frequently require long-haul transmission on a system that is already congested.

23 / Solar Electric Industries Association (SEIA)/Wood Mackenzie Power & Renewables U.S, Solar Market Insight Report, Q3 2020: https://www.seia.org/research-resources/solar-market-insight-report-2020-q3
24 / Solar Electric Industries Association (SEIA), Solar Spotlight – California for Q3 2018, December 2018: https://www.seia.org/sites/default/files/2018-12/Federal_2018Q3_California_1.pdf
25 / Solar Electric Industries Association (SEIA), Solar Market Insight Report, Q3 2020: https://www.seia.org/research-resources/solar-market-insight-report-2020-q3

Onshore and Offshore Wind. For this IRP, wind was modeled in the following locations: eastern Washington, central and eastern Montana, western and eastern Wyoming, eastern Idaho and Washington offshore. Figure D-29 summarizes the assumptions for generic wind resources.

Eastern Washington wind is located in BPA's balancing authority, so this wind requires only one transmission wheel through BPA to PSE. Montana wind, however, is outside BPA's balancing authority and will require four transmission wheels plus various system upgrades to deliver the power to PSE's service territory. Similarly, the Wyoming and Idaho wind sites are well outside PSE's service territory and will require multiple transmission wheels to deliver the power. PSE is investigating potential ownership of transmission on the Boardman to Hemingway[26] and Gateway West[27] transmission projects currently under construction by Idaho Power and Rocky Mountain Power.

PSE is modeling offshore wind located 3 miles off the coast of Grays Harbor County, Wash. Offshore wind would require a marine cable to interconnect all of the turbines and bring the power back to land. Once on land, it would require a transmission wheel through BPA to PSE.

Specific shapes were derived for each generic wind resource. Wind speed at 100 meters above ground level was obtained from the NREL Wind Toolkit database.[28] For each wind resource location, the database was queried to return all wind profiles within a 50 to 75 mile radius of the point of interest. All of these wind speed profiles, typically 1,000 to 2,000 unique profiles, are then processed with a heuristic wind production model. The wind production model performs the following steps:

- A power curve for a modern, 3 MW, 140 meter rotor diameter turbine is adjusted for site specific air density.
- The wind speed data is processed through the power curve to calculate gross power production.
- A heuristic loss estimation model is used to apply loss factors to the gross production value to obtain net production. Losses include:
    - Turbine interaction effects (waking and blockage)
    - Availability (estimated as a stochastic loss)
    - Temperature loss (based on power curve information)
    - Icing losses (estimated using the International Energy Agency [IEA] Icing Class[29] and applied as a stochastic loss)
    - Degradation, performance and other losses

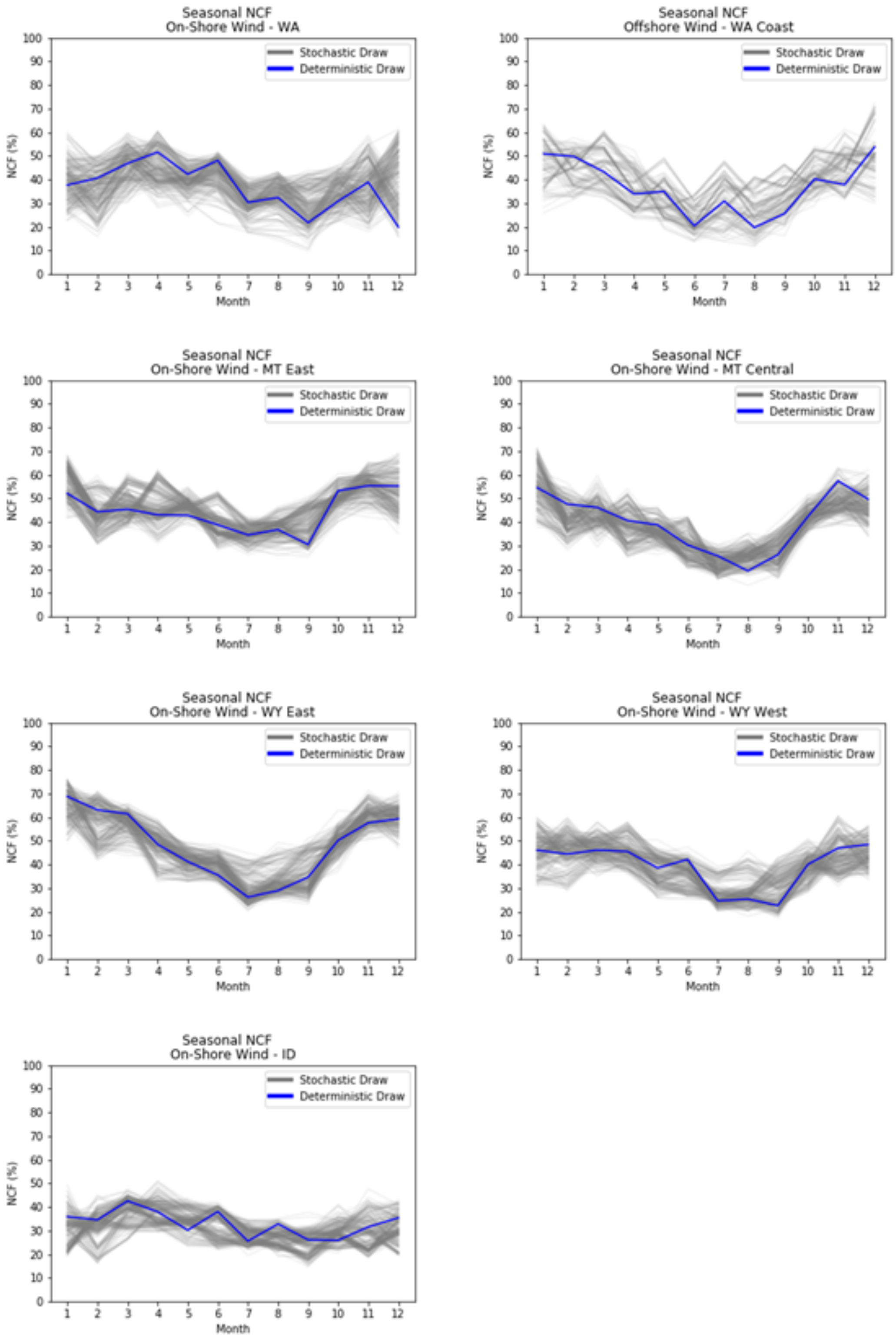
26 / https://www.boardmantohemingway.com/
27 / http://www.gatewaywestproject.com/
28 / https://www.nrel.gov/grid/wind-toolkit.html
29 / http://virtual.vtt.fi/virtual/wiceatla/

After all profiles were processed by the wind production model, 250 representative draws are selected from the complete list. Representative draws are selected based on a least-squares regression to the seasonal average production of all the wind profiles sampled. Finally a single, most-representative draw is selected from the 250 draws using the same selection process. Figure D-30 provides a summary of the seasonal wind shapes used in the 2021 IRP; the grey lines represent each of the 250 stochastic draws and the blue line represents the draw selected as most-representative.

Figure D-29: Wind Generic Resource Assumptions

2020 $	Units	On-Shore Wind MT East	On-Shore Wind MT Central	On-Shore Wind SE Wash.	Off-shore Wind WA Coast	On-Shore Wind WY West	On-Shore Wind WY East	On-Shore Wind ID
ISO Capacity Primary	MW	200	200	100	100	400	400	400
Capacity Credit (2027)	%	21.8%	30.1%	17.8%	48.4%	27.6%	40.0%	24.2%
Operating Reserves	%	3%	3%	3%	3%	3%	3%	3%
Capacity Factor	%	44.3%	39.8%	36.7%	34.8%	39.2%	47.9%	33.0%
Capital Cost	$/KW	$1,806	$1,806	$1,806	$5,609	$1,806	$1,806	$1,806
O&M Fixed	$/KW-yr	$41	$41	$41	$110	$41	$41	$41
O&M Variable	$/MWh	$0	$0	$0	$0	$0	$110	$0
Land Area	acres/MW	48.2	48.2	48.2	N/A	48.2	48.2	48.2
Degradation	%/year	0%	0%	0%	0%	0%	0%	0%
Fixed Transmission	$/KW-yr	$49.65	$49.65	$33.36	$33.36	$50.44	$56.16	$35.36
Variable Transmission	$/MWh	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Loss Factor to PSE	%	4.6%	4.6%	1.9%	1.9%	5.0%	5.0%	4.0%
DEVELOPMENT PARAMETERS								
First Year Available		2024	2024	2024	2030	2026	2026	2026
Economic Life	years	30	30	30	30	30	30	30
Greenfield Dev. & Const. Lead Time	years	2.0	2.0	2.0	3.2	2.0	2.0	2.0

Figure D-30: Seasonal Wind Shapes



Land-based Wind Technology

Land-based wind turbine generator technology is mature and the dominant form of new renewable energy generation in the Pacific Northwest. While the basic concept of a wind turbine has remained generally constant over the last several decades, the technology continues to evolve, yielding higher towers, wider rotor diameters, greater nameplate capacity and increased wind capture (efficiency). Commercially available turbines are in the 2.0 to 4.0 MW range with hub heights of 80 to 130[30] meters and blade diameters up to160 meters. These changes have come about largely because development of premium high-wind sites has pushed new development into less-energetic wind sites. The current generation of turbines is pushing the physical limits of existing transportation infrastructure. In addition, if nameplate capacity and turbine size continue to increase, the industry must explore creative solutions for ever taller towers, such as concrete tower sections poured or stacked on site and segmented blades for final assembly on site.

Commercial Availability. Declining and expiring tax incentives will likely drive demand in the short term. Greenfield development of a new wind facility requires approximately two to three years and consists of the following activities at a minimum: one to two years for development, permitting and major equipment lead time, and one year for construction.

Cost and Performance Assumptions. The cost for installing a wind turbine includes the turbine, foundation, roads and electrical infrastructure. Installed cost for a typical facility in the Northwest region is approximately $1,319 per kW. The levelized cost of energy for wind power is a function of the installed cost and the performance of the equipment at a specific site, as measured by the capacity factor. The all-in levelized cost of energy ranges from $28.79 to $55.32 per MWh (in 2019 U.S. dollars), which is very dependent on the capacity factor of wind at the location.[31]

Offshore Wind Technology

Offshore winds tend to blow harder and more uniformly than on land. The potential energy produced from wind is directly proportional to the cube of the wind speed. As a result, increased wind speeds of only a few miles per hour can produce a significantly larger amount of electricity. For instance, a turbine at a site with an average wind speed of 16 mph would produce 50 percent more electricity than at a site with the same turbine and average wind speeds of 14 mph.

30 / One hundred meters is equivalent to 328 feet which is equivalent to a 30-story building.
31 / U.S. Energy Information Administration (EIA), Annual Energy Outlook 2020, January 2021: https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf. Levelized cost of energy assumes tax credits available for plants entering service in 2022.

Wind turbine generators used in offshore environments include durability modifications to prevent corrosion and operate reliably in the harsh marine environment. Their foundations must be designed to withstand storm waves, hurricane-force winds and even ice floes. The engineering and design of offshore wind facilities depends on site-specific conditions, particularly water depth, geology of the seabed, and expected wind and wave loading. Foundations for offshore wind fall into two major categories, fixed and floating, with a variety styles for each category. The fixed foundation is a proven technology that is used throughout Europe. Monopiles are the preferred foundation type, which are steel piles driven into the seabed to support the tower and shell. Fixed foundations can be installed to a depth of 60 meters.

Roughly 90 percent of the offshore U.S. wind energy resource occurs in waters too deep for current fixed foundation technology, particularly on the West Coast. The wind industry is developing new technologies, such as floating wind turbines, that will allow wind construction in the harsher conditions associated with deeper waters.

All power generated by offshore wind turbines must be transmitted to shore and connected to the power grid. Each turbine is connected to an electric service platform (ESP) by a power cable. High voltage cables, typically buried beneath the sea bed, transmit the power collected from wind turbines from the ESP to an onshore substation where the power is integrated into the grid.

Cost and Performance Assumptions Offshore wind installations have higher capital and operational costs than land-based installations per unit of generating capacity, largely because of turbine upgrades required for operation at sea and increased costs related to turbine foundations, balance of system infrastructure, interconnection and installation, and the difficulty of maintenance access. In addition, one-time costs are associated with the development of infrastructure to support offshore construction, such as vessels for foundation erection and turbine installation and related port facilities.

The United States currently has one operational offshore wind project – the 30 MW Block Island Wind Farm off the coast of Rhode Island which began operation in December 2016. The American Wind Energy Association (AWEA) notes that the two-turbine 12 MW Coastal Virginia Offshore Wind pilot project completed construction in June of 2020 and will start commercial operation later in the year. As a result, reliable capital cost estimates for large-scale U.S. installations are not available. Offshore wind would benefit from a continuation of federal and state government mandates, renewable portfolio standards, subsidies and tax incentives to help innovate and solidify the market. According to AWEA, project developers currently expect 14 offshore wind projects totaling 9,112 MW to be operational by 2026. As the market develops, costs should decrease as experience is gained. Based on the current design trajectory of wind turbine development, bigger units will be able to capture more wind and achieve greater economies of scale in the years ahead.[32]

Commercial Availability. In Europe, offshore wind is a proven technology in shallow coastal waters. Some 14.5 GW have been installed since 1991 with a total installed capacity of 22.1 GW as of 2019, and costs continue to stabilize. The U.S. is just beginning the process of developing offshore wind; however, thousands of megawatts of future development are currently in the planning stages, mostly in the Northeast and Mid-Atlantic regions. Projects are also being considered along the Great Lakes, the Gulf of Mexico and the Pacific Coast. The floating platforms required for deep water offshore wind are yet not commercially mature.

Hybrid Resources

Hybrid resources combine two or more resources at one location to take advantage of synergies created through co-location of the resources. Hybrid resources may combine two generating resources such as solar and wind, or one generating and one storage resource such as solar and a battery energy storage system. Benefits of hybrid resources include reduced land use needs, shared interconnection and transmission costs, improved frequency regulation, backup power potential and operational balancing potential, among others. From 2017 to 2020, the number of installed hybrid systems in the U.S. has more than doubled from less than 30 to 80 facilities.[33]

PSE is evaluating three hybrid systems, each of which pairs a generating resource with a storage resource. These hybrid resources include Washington wind plus 2-hour Lithium-ion battery storage, Washington utility solar plus 2-hour Lithium-ion battery storage, and eastern Montana wind plus pumped hydroelectricity storage. PSE configured the hybrid resources in the model so the storage resource can only charge using the energy from the renewable resource to which it is connected. This is different than co-located resources, which allow the storage resource to be independent of the renewable resource; this is an important distinction for federal tax incentive programs such the Investment Tax Credit (ITC).

32 https://www.energy.gov/eere/wind/offshore-wind-research-and-development
33 / https://www.eia.gov/todayinenergy/detail.php?id=43775

Figure D-31: Hybrid Generic Resource Assumptions

2020 $	UNITS	MT Wind + Pumped Hydro	Wind + Battery	Solar + Battery
ISO Capacity Primary	MW	300	125	125
Capacity Credit (2027)	%	54.3%	23.6%	14.4%
Operating Reserves	%	3%	3%	3%
Capacity Factor	%	44.3%	36.7%	24.2%
Capital Cost	$/KW	$4,016	$2,680	$2,563
O&M Fixed	$/KW-yr	$57	$64	$46
O&M Variable	$/MWh	$0	$0	$0
Land Area	acres/MW	48.2	48.2	5 - 7
Degradation	%/year	0.0%	0.5%	0.5%
Fixed Transmission	$/KW-yr	$50	$33	$30
Variable Transmission	$/MWh	TBD	TBD	TBD
Loss Factor to PSE	%	4.6%	1.9%	1.9%
First Year Available		2028	2024	2024
Economic Life	years	30	30	30
Greenfield Dev. & Const. Lead Time	years	5 - 8	2.0	1.0
Operating Range	%	147-500 MW	2.0%	2.0%
R/T Efficiency	%	80.0%	82.0%	82.0%
Discharge at Nominal Power	hours	8.0	2.0	2.0

Renewable Resources Not Modeled

FUEL CELLS. Fuel cells combine fuel and oxygen to create electricity, heat, water and other by-products through a chemical process. Fuel cells have high conversion efficiencies from fuel to electricity compared to many traditional combustion technologies, on the order of 25 to 60 percent. In some cases, conversion rates can be boosted using heat recovery and reuse. Fuel cells operate and are being developed at sizes that range from watts to megawatts. Smaller fuel cells power items like portable electric equipment, and larger ones can be used to power equipment, buildings or provide backup power. Fuel cells differ in the membrane materials used to separate fuels, the electrode and electrolyte materials used, operating temperatures and scale (size). Reducing cost and improving durability are the two most significant challenges to fuel cell commercialization. To be economical, fuel cell systems must be cost-competitive with, and perform as well as, traditional power technologies over the life of the system.[34]

Provided that feedstocks are kept clean of impurities, fuel cell performance can be very reliable. They are often used as backup power sources for telecommunications and data centers, which require very high reliability. In addition, fuel cells are starting to be used for commercial combined heat and power applications, though mostly in states with significant subsidies or incentives for fuel cell deployment.

Commercial Availability. Fuel cells have been growing in both number and scale, but they do not yet operate at large scale. According to the Department of Energy's report *State of the States: Fuel Cells in America 2017*,[35] there are fuel cell installations in 43 states, and more than 235 MW of large stationary (100 kW to multi-megawatt) fuel cells are currently operating in the U.S. The report further states that California remains the leader with the greatest number of stationary fuel cells. In some states, incentives are driving fuel cell pricing economics to be competitive with retail electric prices, especially where additional value can be captured from waste heat. Currently, Washington State offers no incentives specific to stationary fuel cells. The EIA, estimates fuel cell capital costs to be approximately $6,700 per kW.[36]

GEOTHERMAL. Geothermal generation technologies use the natural heat under the surface of the earth to provide energy to drive turbine generators for electric power production. Geothermal energy production falls into four major types.

Dry Steam Plants use hydrothermal steam from the earth to power turbines directly. This was the first type of geothermal power generation technology developed.[37]

34 / U.S. Department of Energy, Energy Efficiency and Renewable Energy, Fuel Cell Technologies Program.
35 / U.S. Department of Energy's report, "State of the States: Fuel Cells in America 2017," dated January 2018, https://www.energy.gov/sites/prod/files/2018/06/f53/fcto_state_of_states_2017_0.pdf
36 / U.S. Energy Information Agency Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies, February 2020
37 / http://energy.gov/eere/geothermal/electricity-generation

Flash Steam Plants operate similarly to dry steam plants, but they use low-pressure tanks to vaporize hydrothermal liquids into steam. Like dry steam plants, this technology is best suited to high-temperature geothermal sources (greater than 182 degrees Celsius).[38]

Binary-cycle Power Plants can use lower temperature hydrothermal fluids to transfer energy through a heat exchanger to a fluid with a lower boiling point. This system is completely closed-loop, no steam emissions from the hydrothermal fluids are released at all. The majority of new geothermal installations are likely to be binary-cycle systems due to the limited emissions and the greater number of potential sites with lower temperatures.[39]

Enhanced Geothermal or "hot dry rock" technologies involve drilling deep wells into hot dry or nearly dry rock formations and injecting water to develop the hydrothermal working fluid. The heated water is then extracted and used for generation.[40]

Geothermal plants typically run with high uptime, often exceeding 85 percent. However, plants sometimes do not reach their full output capacity due to lower than anticipated production from the geothermal resource.

Commercial Availability. In 2019, there were geothermal power plants in seven states, which produced about 16 GWh, equal to 0.4% of total U.S. utility-scale electricity generation.[41] As of November 2019, 2.5 GW of geothermal generating capacity was online in the United States.[42] Operating geothermal plants in the Northwest include the 28.5 MW Neal Hot Springs plant and the 15.8 MW Raft River plant in Idaho.

The EIA estimates capital costs for geothermal resources to be approximately $2,521/MW.[43] Because geothermal cost and performance characteristics are specific for each site, this represents the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located. Overall, site-specific factors including resource size, depth and temperature can significantly affect costs.

38 / Ibid
39 / Ibid
40 / http://energy.gov/sites/prod/files/2014/02/f7/egs_factsheet.pdf
41 U.S. Energy Information Administration, https://www.eia.gov/energyexplained/geothermal/use-of-geothermal-energy.php
42 / U.S. Energy Information Administration, https://www.eia.gov/todayinenergy/detail.php?id=42036
43 / U.S. Energy Information Administration, Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies, February 2020

WASTE-TO-ENERGY TECHNOLOGIES. Converting wastes to energy is a means of capturing the inherent energy locked into wastes. Generally, these plants take one of the following forms.

Waste Combustion Facilities. These facilities combust waste in a boiler and use the heat to generate steam to power a turbine that generates electricity. This is a well-established technology, with 86 plants operating in the United States, representing 2,720 MW in generating capacity. According to the U.S. EPA's web site, no new facilities have opened since 1995, although some existing facilities have expanded their capacity to convert more waste into electricity.[44]

Waste Thermal Processing Facilities. This includes gasification, pyrolysis and reverse polymerization. These facilities add heat energy to waste and control the oxygen available to break down the waste into components without combusting it. Typically, a syngas is generated, which can be combusted for heat or to produce electricity. A number of pilot facilities once operated in the United States, but only a few remain today.

Landfill Gas and Municipal Wastewater Treatment Facilities. Most landfills in the United States collect methane from the decomposition of wastes in the landfill. Many larger municipal wastewater plants also operate anaerobic systems to produce gas from their organic solids. Both of these processes produce a low-quality gas with approximately half the methane content of natural gas. This low-quality gas can be collected and scrubbed to remove impurities or improve the heat quality of the gas. The gas can then be used to fuel a boiler for heat recovery, or a turbine or reciprocating engine to generate electricity. According to the U.S. EPA's web site, as of August 2020, there are 565 operational landfill gas energy projects in the United States.[45]

44 / U.S. Environmental Protection Agency website. Retrieved from https://www.epa.gov/smm/energy-recovery-combustion-municipal-solid-waste-msw#01, January 2019.
45 / U.S. Environmental Protection Agency website. Retrieved from https://www.epa.gov/lmop/basic-information-about-landfill-gas, August 2020.

Commercial Availability. Washington's RPS initially included landfill gas as a qualifying renewable energy resource, but excluded municipal solid waste. The passage of Washington State Senate bill ESSB 5575 later expanded the definitions of wastes and biomass to allow some new wastes, such as food and yard wastes, to qualify as renewable energy sources.

Currently, several waste-to-energy facilities are operating in or near PSE's electric service area. Three waste facilities – the H.W. Hill Landfill Gas Project, the Spokane Waste-to-Energy Plant and the Emerald City facility – use landfill gas for electric generation in Washington state; combined, they produce up to 67 MW of electrical output. The H.W. Hill facility in Klickitat County is fed from the Roosevelt Regional Landfill and capable of producing a maximum capacity of 36.5 MW.[46] The Spokane Waste-to-Energy Plant processes up to 800 tons per day of municipal solid waste from Spokane County and is capable of producing up to 22 MW of electric capacity.[47] Emerald City uses landfill gas produced at the LRI Landfill in Pierce County to generate up to 4.8 MW of electricity. The facility became commercially operational in December 2013.[48] PSE purchases the electricity produced by the facility through a power purchase agreement under a Schedule 91 contract, which is discussed above.

The largest landfill in PSE's service territory, the Cedar Hills landfill, currently purifies its gas to meet pipeline natural gas quality; they then sell that gas to PSE rather than using it to generate electricity.

Cost and Performance Assumptions. Relatively few new waste combustion and landfill gas-to-energy facilities have been built since 2010, making it difficult to obtain reliable cost data. The EIA's *Annual Energy Outlook 2018* estimates municipal solid waste-to-energy costs to be approximately $8,742 per kW.

In general, waste-to-energy facilities are highly reliable. They have used proven generation technologies and gained considerable operating experience for more than 30 years. Some variation of output from landfill gas facilities and municipal wastewater plants is expected due to uncontrollable variations in gas production. For waste combustion facilities, output is typically more stable, as the amount of input waste and heat content can be more easily controlled.

46 / Phase 1 of the H.W. Hill facility consists of five reciprocating engines, which combined produce 10.5 MW. Phase 2, completed in 2011, adds two 10 MW combustion turbines, and a heat recovery steam generator and steam turbine for an additional 6 MW. Source: Klickitat PUD website. Retrieved from http://www.klickitatpud.com/topicalMenu/about/powerResources/hwHillGasProject.aspx, January 2019.
47 / Spokane Waste to Energy website. Retrieved from https://my.spokanecity.org/solidwaste/waste-to-energy/, January 2019.
48 / BioFuels Washington, LLC landfill gas to energy facility (later sold to Emerald City Renewables, LLC and renamed Emerald LFGTE Facility). Retrieved from https://energyneeringsolutions.com/wp-content/uploads/2018/02/ESI_CaseStudy_Emerald.pdf, January 2019.

WAVE AND TIDAL. The natural movement of water can be used to generate energy through the flow of tides or the rise and fall of waves.

Tidal Generation technology uses tidal flow to spin rotors that turn a generator. Two major plant layouts exist: barrages, which use artificial or natural dam structures to accelerate flow through a small area, and in-stream turbines, which are placed in natural channels. The Rance Tidal Power barrage system in France was the world's first large-scale tidal power plant. It became operational in 1966 and has a generating capacity of approximately 240 MW. The Sihwa Lake Tidal Power Station in South Korea is currently the world's largest tidal power facility. The plant was opened in late 2011 and has a generating capacity of approximately 254 MW. The 20 MW Annapolis Royal Generating Station in Nova Scotia, Canada, is the world's next-largest operating tidal generation facility. China, Russia and South Korea have smaller tidal power installations.[49] Also worth noting is the planned 400 MW Mey Gen Tidal Energy Project in Scotland, which if completed, would be the largest tidal generation facility in the world. The project is designed to be constructed in multiple phases with final deployment targeted for 2021. A 6 MW portion of the first phase began operating in April 2018.[50]

Wave Generation technology uses the rise and fall of waves to drive hydraulic systems, which in turn fuel generators. Technologies tested include floating devices such as the Pelamis and bottom-mounted devices such as the Oyster. The largest wave power plant in the world was the 2.25 MW Agucadoura Wave Farm off the coast of Portugal, which opened in 2008.[51] It has since been shut down because of the developer's financial difficulties.

In 2015, a prototype wave energy device developed by Northwest Energy Innovations was successfully launched and installed for grid-connected, open-sea pilot testing at the Navy's Wave Energy Test Site in Kaneohe Bay on the island of Oahu, Hawaii. According to the U.S. Department of Energy's web site, the 20 kW Azura device is the nation's first grid-connected wave energy converter device.[52]

49 / U.S. Energy Information Administration website. Retrieved from https://www.eia.gov/energyexplained/index.php?page=hydropower_tidal, January 2019.
50 / Wikipedia website. Retrieved from https://en.wikipedia.org/wiki/MeyGen, January 2019.
51 / CNN website. Retrieved from http://www.cnn.com/2010/TECH/02/24/wave.power.buoys/index.html, February 2010.
52 / The U.S. Department of Energy website. Retrieved from https://www.energy.gov/eere/articles/innovative-wave-power-device-starts-producing-clean-power-hawaii, July 2015.

Commercial Availability. Since mid-2013, a number of significant wave and tidal projects and programs have slowed, stalled or shut down altogether. In general, wave and tidal resource development in the U.S. continues to face limiting factors such as funding constraints, long and complex permitting process timelines, relatively little experience with siting and the early stage of the technology's development. FERC oversees permitting processes for tidal power projects, but state and local stakeholders can also be involved. After permits are obtained, studies of the site's water resource and aquatic habitat must be made prior to installation of test equipment.

There are three demonstration tidal projects in various stages of development of the United States, located in Roosevelt Island (New York), Western Passage (Maine) and Cobscook Bay (Maine). Currently, there are no operating tidal or wave energy projects on the West Coast. In late 2014, Snohomish PUD abandoned plans to develop a 1 MW tidal energy installation at the Admiralty Inlet.[53] Several years ago, Tacoma Power considered and later abandoned plans to pursue a project in the Tacoma Narrows.

Tidal and wave generation technologies are very early in development, making cost estimates difficult. Most developers have not produced more than one full-scale device, and many have not even reached that point. Few wave and tidal technologies have been in operation for more than a few years and their production volumes are limited, so costs remain high and the durability of the equipment over time is uncertain.

Energy Storage Resource Costs and Technologies

PSE modeled three energy storage alternatives in the 2019 IRP: lithium-ion batteries, flow batteries and pumped hydro energy storage (PHES).

GENERIC ENERGY STORAGE RESOURCE COST ASSUMPTIONS. Figure D-32 summarizes the generic costs assumptions used in the analysis for energy storage resources. All costs are in 2020 dollars.

53 / The Seattle Times website. Retrieved from http://www.seattletimes.com/seattle-news/snohomish-county-pud-drops-tidal-energy-project/, October 2014.

Figure D-32: Generic Energy Storage Assumptions

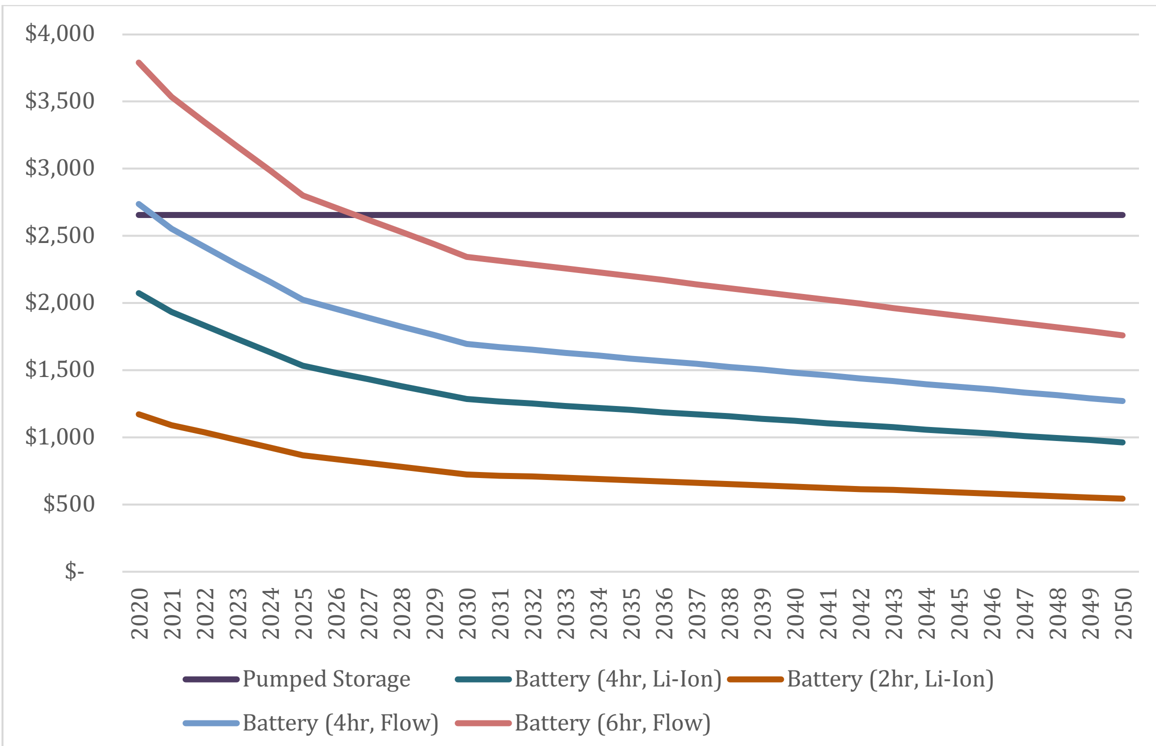
2020 $	UNITS	Pumped Hydroelectric Storage	Battery Energy Storage System (BESS)			
		Closed Loop (8 Hour)	Li-Ion 2-hr (2 Cycles Daily)	Li-Ion 4-hr (2 Cycles Daily)	Flow 4-hr (2 Cycles Daily)	Flow 6-hr (2 Cycles Daily)
Nameplate Capacity	MW	25	25	25	25	25
Capacity Credit (2027)	%	37.2%	12.4%	24.8%	22.2%	29.8%
Operating Reserves	%	3%	3%	3%	3%	3%
Capital Cost	$/KW	$2,656	$1,172	$2,074	$2,738	$3,791
O&M Fixed (c)	$/KW-yr	$16	$23	$32	$22	$38
O&M Variable	$/MWh	$0	$0	$0	$0	$0
Degradation	%/year	(a)	(d)	(d)	(d)	(d)
Operating Range	%	147-500 MW (b)	2.0%	2.0%	2.0%	2.0%
R/T Efficiency	%	80%	82%	87%	73%	73%
Discharge at Nominal Power	Hours	8	2	4	4	6
Maximum Storage	MWh	200	50	100	100	150
Fixed Transmission	$/KW-yr	$22	$0	$0	$0	$0
Variable Transmission	$/MWh	TBD	TBD	TBD	TBD	TBD
First Year Available		2028	2023	2023	2023	2023
Economic Life	years	30	30	30	30	30
Greenfield Dev. & Const. Lead time	years	5 - 8	1	1	1	1

NOTES
Pumped Hydroelectric Storage (PHES) - assumed to represent a slice of a larger project.
a - PHES degradation close to zero
b - The operating range minimum is the average of the minimum at max (111 MW) and min head (183 MW).
c - Fixed O&M costs for Lithium-ion batteries include augmentation by OEM ensuring MW and MWh rating for project life.
d - Battery can discharge up to the indicated percent of nameplate.

CAPITAL COST CURVE. Capital costs assumptions start in current the current year, but for future years, the cost curve from the NREL Annual Technology Baseline (ATB) 2019 was applied to the current costs.

Figure D-33 below shows the capital cost curves for the energy storage resources modeled in the 2021 IRP.

Figure D-33: Capital Cost Curve for Energy Storage



Energy Storage Characteristics

Energy storage encompasses a wide range of technologies that are capable of shifting energy usage from one time period to another. These technologies could deliver important benefits to electric utilities and their customers, since the electric system currently operates on "just-in-time" delivery. Generation and load must be perfectly balanced at all times to ensure power quality and reliability. Strategically placed energy storage resources have the potential to increase efficiency and reliability, to balance supply and demand, to provide backup power when primary sources are interrupted and to assist with the integration of intermittent renewable generation. Energy storage technologies are rapidly improving and are capable of benefiting all parts of the system – generation, transmission and distribution – as well as customers. The drawbacks to energy storage are that it operates with a limited duration and requires generation from other sources.

Battery Storage Technologies

Unlike conventional generation resources such as combustion turbines, battery storage resources are modular, scalable and expandable. They can be sized from 20 kW to 1,000 MW and sited at a customer's location or interconnected to the transmission system. It is possible to build the infrastructure for a large storage system and install storage capacity in increments over time as needs grow. This flexibility is a valuable feature of the technology.

Within the battery category, there are many promising chemistries, each with its own performance characteristics, commercial availability and costs. PSE chose to model lithium-ion and flow batteries as the generic battery resources in this IRP because both technologies are commercially available, there are successful projects in operation, and cost estimates and data are available on a spectrum of system configurations and sizes. Other advantages are described below.[54]

LITHIUM-ION BATTERIES have emerged as the leader in utility-scale applications because they offer the best mix of performance specifications for most energy storage applications. Advantages include high energy density, high power, high efficiency, low self-discharge, lack of cell "memory" and fast response time. Challenges include short cycle life, high cost, heat management issues, flammability and narrow operating temperatures. Battery degradation is dependent on the number of cycles and state of the battery's charge. Deep discharge will hasten the degradation of a lithium-ion battery. Lithium-ion batteries can be configured for varying durations (i.e., 0.5 to 6 hours), but the longer the duration, the more expensive the battery. Lithium-ion storage is ideally suited for ancillary applications benefitted by high power (MW), low energy solutions (MWh), and to a lesser extent, for supplying capacity.

54 / In an actual RFP solicitation, PSE would evaluate all proposed technologies based on least-cost and best-fit criteria, including technical and commercial considerations such as warranties, performance guarantees and counterparty credit, etc.

In late 2015, PSE started construction on a 2-megawatt (MW), 4.4 megawatt-hour (MWh) lithium-ion battery system adjacent to the existing substation in the Whatcom County town of Glacier. The project is funded in part by a $3.8 million Smart Grid grant from the Washington State Department of Commerce, in addition to a $7.4 million investment by PSE. The battery was energized in 2016, and in January, 2017, achieved its first successful islanding attempt. Between January, 2018 and June, 2018, Pacific Northwest National Laboratory (PNNL) performed two use test cases. Since then, PSE has continued to test the battery's capabilities under planned outage scenarios – working toward the goal of successfully responding to unplanned outages. As of August, 2019, PSE has successfully powered Glacier's town core through more than six planned outages. The Glacier battery's first successful unplanned response occurred on February 4, 2019, when the battery remotely responded to an outage and provided power for approximately 4 hours until repairs were made to the transmission line.

FLOW BATTERIES are a type of rechargeable battery in which recharge ability is provided by two chemical components dissolved in liquids contained within the system. The two components are separated by a membrane, and ion exchange occurs through the membrane while both liquids circulate in their respective spaces. The ion exchange provides the flow of electric current. Flow batteries can provide the same services as lithium-ion batteries, but they can be used with more flexibility because they do not degrade over time. Flow batteries have limited market penetration at this time, but are an emerging battery storage technology. In 2016, Avista Utilities installed the first large-scale U.S.[55] flow battery storage system in Washington, and in 2017 two additional flow battery facilities were installed by electric utilities in Washington and California. Approximately 70 MW and 250 MWh of flow batteries, almost all in medium- to large-scale projects, have been deployed worldwide.[56]

Commercial availability. At the end of 2018, the U.S. had 869 MW of large-scale battery energy storage resources in operation. Lithium-ion batteries continued to dominate the energy storage market, representing more than 90 percent of operating large-scale battery storage capacity. In 2018, U.S. utilities also reported 234 MW of existing small-scale storage capacity.[57] Just over 50 percent of this capacity was installed in the commercial sector, 31 percent in the residential sector and 15 percent in the industrial sector, with the remaining 3 percent directly connected to the distribution grid.

55 / Large-scale refers to a facility that is typically grid connected and greater than 1 MW in capacity. Small-scale refers to systems typically connected to a distribution system that are less than 1 MW in power capacity.
56 / IDTechEx Research, Batteries for Stationary Energy Storage 2019-2029
57 / U.S. Energy Information Administration, U.S. Battery Storage Market Trends, July 2020: https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf

Pumped Hydroelectric Storage Technology

Pumped hydroelectric storage ("pumped storage" or "pumped hydro") plants provide the bulk of utility-scale energy storage in the United States. These facilities store energy in the form of water, which is pumped to an upper reservoir from a second reservoir at a lower elevation. During periods of high electricity demand, the stored water is released through turbines to generate power in the same manner as a conventional hydropower station. Load shifting over a number of hours requires a large volume of energy storage capacity, and a storage device like pumped hydro is well suited for this type of application. During periods of low demand (usually nights or weekends when electricity costs less), the upper reservoir is "recharged" by using lower-cost electricity from the grid to pump the water back to the upper reservoir.

Reversible pump-turbine and motor-generator assemblies can act as both pumps and turbines. Pumped storage facilities can be very economical due to peak and off-peak price differentials and because they can provide critical ancillary grid services. Pumped storage projects are traditionally large, at 300 MW or more. Due to environmental impacts, permitting for these projects can take many years. Pumped storage can be designed to provide 6 to 20 hours of storage with 80 percent roundtrip efficiency.

Commercial availability. According to the Department of Energy's most recent *Hydropower Market Report*, there are 43 plants with a capacity of 21.6 GW, which represent 95 percent of utility-scale electrical energy storage in the U.S. Most of this capacity was installed between 1960 and 1990, and almost 94 percent of these storage facilities are larger than 500 MW. No new pumped storage projects have come online in the United States since 2012.[58] At the end of 2017, there were 48 pumped storage projects with a potential capacity of 19.7 GW in the FERC development pipeline. Typical proposed project size remains large; however, the median size of proposed projects decreased from 600 MW at the end of 2014 to 290 MW by the end of 2017.[59]

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58 / U.S. Energy Information Agency, Annual Electric Generator Report
59 / U.S. Department of Energy 2017 Hydropower Market Report, published April 2018: https://www.energy.gov/sites/prod/files/2018/04/f51/Hydropower%20Market%20Report%20-%20Executive%20Summary.pdf

Energy Storage Not Modeled

LIQUID AIR ENERGY STORAGE (LAES). LAES converts energy from a variety of sources, such as natural gas or wind, and stores it as thermal energy. To charge the energy, air is cooled and compressed into a liquid state using electricity (i.e., liquefied air or liquefied nitrogen) and stored in tanks. To dispatch electrical energy back to the grid, the liquid air is heated and pressurized, bringing it back to a gaseous state. The gas is used to turn a turbine to generate electricity.

Potential benefits include the technology's suitability to deliver large-scale power for utility and distributed power applications; its suitability for long-duration energy storage; and its ability to use waste heat and cold from its own processes to enhance its efficiency. Also, LAES systems can be large in scale without requiring a large footprint, giving them greater geographical flexibility.

Commercial Availability. LAES systems combine three existing technologies: industrial gas production, cryogenic liquid storage and expansion of pressurized gasses. While the components are based on proven technology currently used in industrial processes and available from large Original Equipment Manufacturers (OEMs), no commercial LAES systems are currently in operation in the U.S. However, in June 2018, Highview Power Storage, a small U.K. company partnering with GE to develop utility-scale LAES systems, launched the world's first grid-scale LAES plant at a landfill gas site near Manchester. The pilot plant is capable of producing 5 MW/15MWh of storage capacity. According to Highview Power Storage, the technology can be scaled up to hundreds of megawatts to better align with the needs of cities and towns.[60]

HYDROGEN ENERGY STORAGE: Hydrogen energy storage systems use surplus renewable electricity to power a process of electrolysis, in which current is passed through a chemical solution to separate and create hydrogen. This renewable hydrogen is then stored for later conversion back into electricity, as well as for other applications such as fuel for transport. Hydrogen does not degrade over time and can be stored for long periods in large quantities, most notably in underground salt caverns. This pure hydrogen can be used for re-electrification in a fuel cell or combusted in a gas turbine.

60 / Forbes website. Retrieved from https://www.forbes.com/sites/mikescott/2018/06/08/liquid-air-technology-offers-prospect-of-storing-energy-for-the-long-term/#3137f759622f, January, 2019.

Commercial Availability. In 2018, Enbridge Gas Distribution and Hydrogenics opened North America's first multi-megawatt power-to-gas facility using renewably sourced hydrogen, the 2.5 MW Markham Energy Storage Facility in Ontario, Canada. In the United States, SoCalGas has partnered with the National Fuel Cell Research Center to install an electrolyzer powered by the University of California at Irvine on-campus solar electric system, which generates renewable hydrogen to be fed into the campus power plant. SoCalGas has also partnered with NREL to install the nation's first biomethanation reactor system located at their Energy Systems Integration Facility (ESIF) in Golden, Colo. Full-scale hydrogen energy projects are also in development, most notably a 1,000 MW Advanced Clean Energy Storage (ACES) facility in Utah through a partnership of Mitsubishi Hitachi Power Systems and Magnum Development, which owns large salt caverns to store the hydrogen. Xcel Energy is partnering with the NREL to create a 110 kW wind-to-hydrogen project using the site's hydrogen fueling station for storage, to be converted back to electricity and fed to the grid during peak demand hours.[61]

Supply-side Thermal Resource Costs and Technologies

PSE modeled two types of thermal resources in the 2019 IRP, baseload combustion turbine plants and peaking capacity plants.

Generic Combustion Turbine Resource Cost Assumptions

Figure D-34 summarizes the cost assumptions used in the analysis for baseload combustion turbine plants and peaking capacity plants. All costs are in 2020 dollars.

61 / Sources: Fuel Cell & Hydrogen Energy Association, Energy Storage Association, Utility Dive

Figure D-34: Generic Combustion Turbine Resource Assumptions

2020 $	UNITS	FRAME PEAKER	CCCT	RECIP PEAKER
		1x0 F-Class Dual Fuel CT (NG)	1x1 F-Class CC (NG Only)	12x0 18 MW RICE (NG Only)
ISO Capacity Primary	MW	225	336	219
Winter Capacity Primary (23º F)	MW	237	348	219
Incremental Capacity DF (23º F)	MW	N/A	19	N/A
Capital Cost + Duct Fire*	$/KW	$947.53	$1,254.53	$1,671.27
O&M Fixed	$/KW-yr	$7.68	$12.87	$6.40
O&M Fixed	$MW-week	$147.63	$247.45	$123.15
O&M Variable	$/MWh	$7.86	$3.32	$7.05
Start-up Costs	$/Start	$6,831.16	N/A	N/A
Operating Reserves	%	3%	3%	3%
Forced Outage Rate	%	2.38%	3.88%	3.30%
Heat Rate – Baseload (HHV)	Btu/KWh	9,904	6,624	8,445
Heat Rate – Turndown (HHV)	Btu/KWh	15,794	7,988	11,288
Heat Rate – DF	Btu/KWh	N/A	8,867	N/A
Minimum Capacity	%	30%	38%	30%
Start Time (hot)	minutes	21	45	5
Start Time (warm)	minutes	21	60	5
Start Time (cold)	minutes	21	150	5
Start-up fuel (hot)	mmBtu	366	839	69
Start-up fuel (warm)	mmBtu	366	1,119	69
mmBtu/MW/Start (warm)		1.544	3.214	0.317
Staru-up fuel (cold)	mmBtu	366	2,797	69
Ramp Rate	MW/min	40	40	16

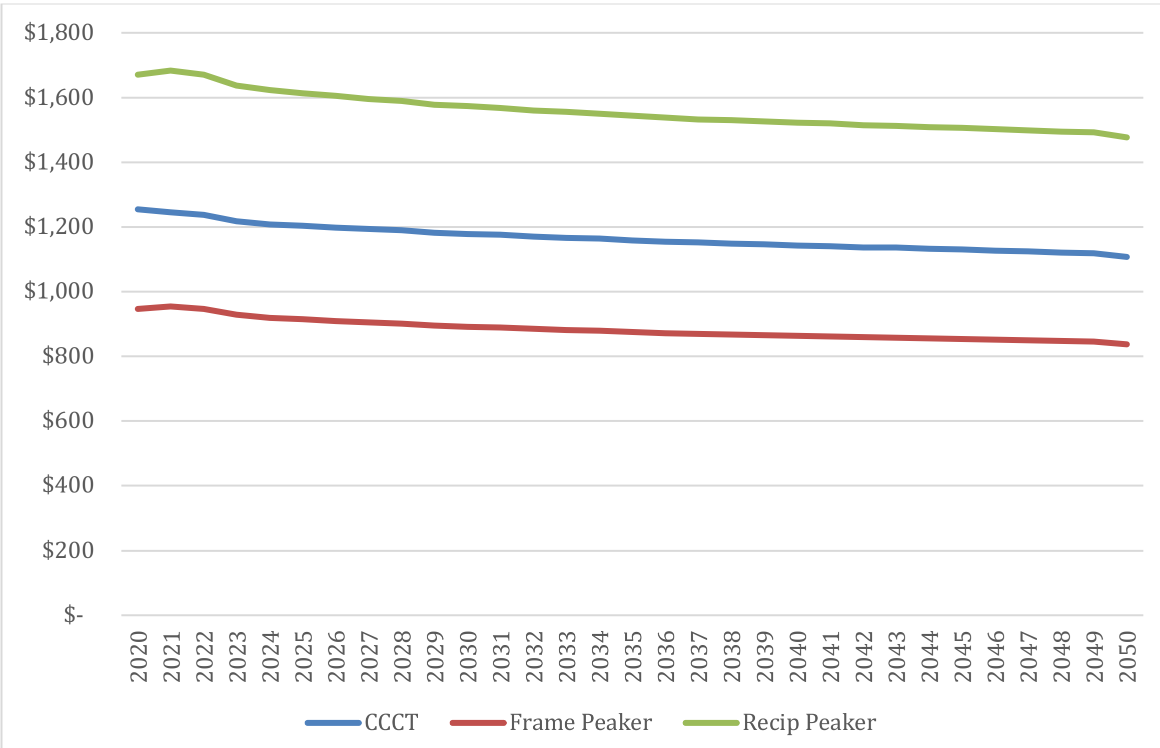
Fixed Gas Transport	$/Dth/Day	$0.00	$0.25	$0.25
Fixed Gas Transport	$/KW-yr	$0.00	$14.67	$18.70
Variable Gas Transport	$/MMBtu	$0.04	$0.06	$0.06
Fixed Transmission	$/KW-yr	$0.00	$0.00	$0.00
Variable Transmission	$/MWh	$0.00	$0.00	$0.00
EMISSIONS				
CO2 - Natural Gas	lbs/MMBtu	118	118	118
NOx - Natural Gas	lbs/MMBtu	0.004	0.008	0.029
DEVELOPMENT PARAMETERS				
First Year Available		2025	2025	2025
Economic Life	years	30	30	30
Greenfield Dev. & Const. Lead Time	years	1.8	2.7	2.3

NOTES
1. For recip peaker, the ramp rate indicated is for a single reciprocating internal combustion engine (RICE) unit; operations and maintenance costs include oil backup.
2. For frame peaker, operations and maintenance costs include oil backup. Variable Operations and Maintenance (VOM) is variable operations only. Major maintenance is included in start-up costs.

CAPITAL COST CURVE. Capital costs assumptions start in current the current year, but for future years, the cost curve from the NREL Annual Technology Baseline (ATB) 2019 was applied to the current costs.

Figure D-35 below shows the capital cost curves for the thermal plants modeled in the 2021 IRP.

Figure D-35: Capital Cost Curve for Thermal Plants



GAS TRANSPORTATION COSTS MODELED. Fixed and variable natural gas transportation costs for the combustion turbine plants assume that natural gas is purchased at the Sumas Hub. Natural gas transportation costs for resources without oil backup assume the need for 100 percent firm gas pipeline transportation capacity plus firm storage withdrawal rights equal to 20 percent of the plant's full fuel requirements. This applies to the baseload CCCT and reciprocating engine without oil. The analysis assumes that the gas transportation needs for these resources will be met with 100 percent firm gas transportation on a Northwest Pipeline (NWP) expansion to Sumas plus 100 percent firm gas transportation on the Westcoast Pipeline[62] expansion to Station 2. The plants are dispatched to Sumas prices, so a basis differential gain between Sumas and Station 2 mitigates the gas transportation costs. For frame peaker resources, we assume oil backup with no firm gas transportation.

62 / *Westcoast Pipeline is operated by Westcoast Energy, a subsidiary of Enbridge, Inc.*

Figure D-36 below shows the natural gas transport assumptions for resources without oil backup.

Figure D-36: Natural Gas Transportation Costs for Western Washington CCCT and Reciprocating Engine Peakers without Oil Backup – 100% Sumas on NWP + 100% Station 2 on Westcoast

PIPELINE/RESOURCE	FIXED DEMAND ($/DTH/DAY)	VARIABLE COMMODITY ($/DTH)	ACA CHARGE ($/DTH)	FUEL USE (%)	UTILITY TAXES (%)
NWP Expansion[1]	0.6900	0.0083	0.0013	1.41%	3.85%
Westcoast Expansion[2]	0.7476	0.0551	-	-	-
Basis Gain[3]	(0.8139)	-	-	2.71%	3.85%
Gas Storage[4]	0.0767	-	-	2.00%	3.85%
Total	***0.7004***	***0.0634***	***0.0013***	***6.12%***	***3.85%***

NOTES
1. Estimated NWP Sumas to PSE Expansion
2. Estimated Westcoast Expansion Fixed Demand
3. Basis gain represents the average of the Station 2 to Sumas price spread, net of fuel losses and variable costs over the 20-year forecast period. Variable Commodity Charge includes B.C. carbon tax and motor fuel tax of $0.0551 per Dth per day and fuel losses are 2.71 percent per Dth. A state utility tax of 3.852% applies to the natural gas price.
4. Storage requirements are based on current storage withdrawal capacity to peak plant demand for the natural gas for power portfolio (approximately 20 percent).

Figure D-37: Natural Gas Transportation Costs for Western Washington Frame Peakers with Oil Backup – No Firm Gas Pipeline

PIPELINE/ RESOURCE	FIXED DEMAND ($/DTH/DAY)	WEIGHTED AVERAGE "VARIABLE" DEMAND ($/DTH)	VARIABLE COMMODITY ($/DTH)	ACA CHARGE ($/DTH)	FUEL USE (%)	UTILITY TAXES (%)
NWP Demand	0.0000	0.0300	0.0083	0.0013	1.41%	3.82%
Total	**0.0000**	**0.0300**	**0.0083**	**0.0013**	**1.41%**	**3.82%**

Combustion Turbine (CT) Characteristics

Combustion turbines still play an important role in the portfolio given their versatility and reliability. PSE is exploring fuel alternatives to natural gas fuel, such as RNG, hydrogen and biodiesel as we move toward CETA goals. The following characteristics make combustion turbines an important tool.

- **Proximity.** Combustion turbines located within or adjacent to PSE's service area avoid costly transmission investments required for long-distance resources like wind.
- **Timeliness.** Combustion turbines are dispatchable, meaning they can be turned on when needed to meet loads, unlike "intermittent" resources that generate power sporadically such as wind, solar and run-of-the-river hydropower.
- **Versatility.** Combustion turbine generators have varying degrees of ability to ramp up and down quickly in response to variations in load and/or wind generation.

When relying on natural gas fuel, storage and fuel supply are important considerations, so the analysis also includes gas storage for some resources. The baseload and peaking resources modeled in this analysis are described below.

Baseload Combustion Turbine (CT) Technologies

Baseload CT plants – combined-cycle combustion turbines or CCCTs – produce energy at a constant rate over long periods at a lower cost relative to other production facilities available to the system. They are typically used to meet some or all of a region's continuous energy demand.

COMBINED-CYCLE COMBUSTION TURBINES (CCCTs). These baseload plants consist of one or more combustion turbine generators equipped with heat recovery steam generators that capture heat from the combustion turbine (CT) exhaust. This otherwise wasted heat is then used to produce additional electricity via a steam turbine generator. The baseload heat rate for the CCCTs modeled for this IRP is 6,624 BTU per kWh. Many plants also feature "duct firing." Duct firing can produce additional capacity from the steam turbine generator, although with less efficiency than the primary unit. CCCTs have been a popular source of baseload electric power and process steam generation since the 1960s because of their high thermal efficiency and reliability, relatively low initial cost and relatively low air emissions.

In this analysis, natural gas supply is assumed to be firm year-round at projected incremental gas pipeline firm rates. This analysis assumes 20 percent of gas storage is available to the baseload CCCT plants modeled to accommodate mid-day start-ups or shutdowns. The unit is assumed to be connected to the PSE transmission system and as such does not incur any direct transmission cost.

This technology is commercially available. Greenfield development requires approximately three years.

Peaker Technologies

Peakers are quick-starting single-cycle combustion turbines that can ramp up and down rapidly in order to meet spikes in need. They also provide flexibility needed for load following, wind integration and spinning reserves. PSE modeled two types of peakers; each brings particular strengths to the overall portfolio.

FRAME PEAKERS. Frame CT peakers are also known as “industrial” or “heavy-duty” CTs; these are generally larger in capacity and feature frames, bearings and blading of heavier construction. Conventional frame CTs are a mature technology. They can be fueled by natural gas, distillate oil or a combination of fuels (dual fuel). The turndown capability of the units is 30 percent. The assumed heat rate for frame peakers in this IRP is 9,904 BTU per kWh. They also have slower ramp rates than other peakers, on the order of 40 MW per minute for 237 MW facilities, and some can achieve full load in twenty-one minutes.

Frame CT peakers are commercially available. Greenfield development requires approximately two years.

RECIP PEAKERS (RECIPROCATING INTERNAL COMBUSTION ENGINE - RICE). The reciprocating engine technology evaluated is based on a four-stroke, spark-ignited gas engine which uses a lean burn method to generate power. The lean burn technology uses a relatively higher ratio of oxygen to fuel, which allows the reciprocating engine to generate power more efficiently. Ramp rates are 16 MW per minute for an 18 MW facility. The heat rate is 8,445 BTU per kWh. However, reciprocating engines are constrained by their size. The largest commercially available reciprocating engine for electric power generation produces 18 MW, which is less than the typical frame peaker. Larger-sized generation projects would require a greater number of reciprocating units compared to an equivalent-sized project implementing a frame turbine, reducing economies of scale. A greater number of generating units increases the overall project availability and reduces the impact of a single unit out of service for maintenance. Reciprocating engines are more efficient than simple-cycle combustion turbines, but have a higher capital cost. Their small size allows a better match with peak loads, thus increasing operating flexibility relative to simple-cycle combustion turbine peakers.

This technology is commercially available. Greenfield development requires approximately three years.

OIL BACKUP. For frame peakers with oil backup, natural gas supply is assumed to be available on an interruptible basis at projected gas pipeline seasonal interruptible rates for much of the year. The oil backup is assumed to provide fuel during peak periods. For units without oil backup, natural gas supply is assumed to be firm year-round at projected incremental gas pipeline firm rates. In either case, the analysis assumes 20 percent of gas storage is available to the peaking gas plants modeled to accommodate mid-day start-ups or shutdowns. The peaker unit is assumed to be connected to the PSE transmission system and as such does not incur any direct transmission cost.

Thermal Resources Not Modeled

As discussed below, other potential thermal resource alternatives are constrained by law, practical obstacles and cost. Long-term coal-fired generation is not a resource alternative because RCW 80.80 precludes utilities in Washington from entering into new long-term agreements for coal. The Clean Energy Transformation Act (CETA) also requires utilities to eliminate coal-fired generation from their state portfolios by 2025. New nuclear generation is neither practical nor feasible.

COAL. Coal fuels a significant portion of the electricity generated in the United States. Most coal-fired electric generating plants combust the coal in a boiler to produce steam that drives a turbine-generator. A small number of plants gasify coal to produce a synthetic gas that fuels a combustion turbine. Of the fuels commonly used to produce electricity, coal produces the most greenhouse gases (GHGs) per MWh of electricity. Technologies for reducing or capturing some of the GHGs produced are currently in the research and development phase.

Commercial Availability. New coal-fired generation is not a resource alternative for PSE, because RCW 80.80 sets a generation performance standard for electric generating plants that prohibits Washington utilities from building plants or entering into long-term electricity purchase contracts from units that emit more than 970 pounds of GHGs per MWh.[63] With currently available technology, coal-fired generating plants produce GHGs (primarily carbon dioxide) at a level two or more times greater than the performance standard, and carbon capture and sequestration technology is not yet effective or affordable enough to significantly reduce those levels. Furthermore, CETA, passed on May 7, 2010, explicitly requires Washington state utilities to eliminate coal-fired electricity generation from their state portfolios by 2025.

There are no new coal-fired power plants under construction or development in the Pacific Northwest.

NUCLEAR. Capital and operating costs for nuclear power plants are significantly higher than most conventional and renewable technologies such that only a handful of the largest capitalized utilities can realistically consider this option. In addition, nuclear power carries significant technology, credit, permitting, policy and waste disposal risks.

63 / To support a long-term plan to shut down the only coal-fired generating plant in Washington state, state government has made an exception for transition contracts with the Centralia generating plant through 2025.

Cost Assumptions. There is little reliable data on recent U.S. nuclear developments from which reasonable and supportable cost estimates can be made. The construction cost and schedule track record for nuclear plants built in the U.S. during the 1980s, 1990s and 2000s has been poor at best. Actual costs have been far higher than projected, construction schedules have been subject to long delays, and interest rate increases have resulted in high financing charges. The Fukushima incident in 2011 also motivated changing technical and regulatory requirements and public controversy that have contributed to project cost increases.

With many other energy options to choose from, the demonstrated high cost, poor completion track record, lack of a comprehensive waste storage/disposal solution and the bankruptcy of a major nuclear supplier all create significant uncertainty, making nuclear energy an unwise and unnecessary risk for PSE at this time.

AERO Peakers (Aeroderivative Combustion Turbines). Aeroderivative combustion turbines are a mature technology, however, new aeroderivative features and designs are continually being introduced. They can be fueled by natural gas, oil or a combination of fuels (dual fuel). A typical heat rate is 8,810 BTU per kWh. Aero units are typically more flexible than their frame counterparts, and many can reduce output to nearly 25 percent. Most can start and achieve full output in less than eight minutes and start multiple times per day without maintenance penalties. Ramp rates are 50 MW per minute for a 227 MW facility. Another key difference between aero and frame units is size. Aero CTs are typically smaller in size, from 5 to 100 MW each. This small scale allows for modularity, but it also tends to reduce economies of scale.

This technology is commercially available. Greenfield development requires approximately three years.

E Conservation Potential Assessment and Demand Response Assessment

This appendix explains the development of the potential assessment for Conservation, Demand Response and Distributed Solar, also referred commonly as the Conservation Potential Assessment (CPA). The CPA is developed by Cadmus Group Consulting as part of PSE's IRP analysis and determines the type and quantity of conservation measures available from utility programs, codes and standards, and other customer driven programs. It also contains a section on the use of demand response in solving grid and pipeline needs. The Cadmus Group report is attached to this document.

CADMUS

Comprehensive Assessment of Demand-Side Resource Potentials (2022 – 2045):

Conservation Potential Assessment

Demand Response Assessment

Distributed Solar Assessment

December 4, 2020

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Acronyms and Abbreviations

Acronym	Definition
ACEEE	American Council for an Energy-Efficient Economy
AMI	Advanced Metering Infrastructure
aMW	Average megawatt
ASP	Annualized simple payback
ATB	Annual technology baseline
BYOT	Bring your own thermostat
C&I	Commercial and industrial
CBECS	Commercial Building Energy Consumption Survey
CBSA	Commercial Building Stock Assessment
CEE	Consortium for Energy Efficiency
CHP	Combined Heat and Power
Council	Northwest Power and Conservation Council
CPA	Conservation Potential Assessment
CPP	Critical peak pricing
DEER	California Database of Energy Efficient Resources
DLC	Direct Load Control
DOE	U.S. Department of Energy
DR	Demand response
DSR	Demand-side resources
EERE	Office of Energy Efficiency and Renewable Technology (U.S. Department of Energy)
EIA	U.S. Energy Information Administration
EISA	Energy Independence and Security Act
ERWH	Electric resistance water heater
EUL	Effective useful life
EV	Electric vehicle
EVSE	Electric vehicle service equipment
FTE	Full-time equivalent
GEWH	Grid-enabled water heater
HB	House Bill
HPWH	Heat pump water heater
HVAC	Heating, ventilation, and air conditioning
IFC	International Fire Code
IRP	Integrated resource plan
LCOE	Levelized cost of electricity
LED	Light-emitting diode
LI	Low income
LIDAR	Light detection and ranging
NEEA	Northwest Energy Efficiency Alliance
NPV	Net present value
NREL	National Renewable Energy Laboratory
O&M	Operations and maintenance
PCT	Programmable communicating thermostat
PSE	Puget Sound Energy
PV	Photovoltaic

Acronym	Definition
RBSA	Residential Building Stock Assessment
RCS	Residential Characteristics Study
RECS	Residential Energy Consumption Survey
RBSA	Residential Building Stock Assessment
RTF	Regional Technical Forum
T&D	Transmission and distribution
TLED	Tubular LED
TOU	Time of use
TRC	Total resource cost
TRM	Technical reference manual
UCT	Utility cost test
UES	Unit energy savings
WSEC	Washington State Energy Code

Executive Summary

Overview

This report presents the results of an independent assessment of the technical and achievable potential for electric and natural gas demand-side resources (DSR) in the service territory of Puget Sound Energy (PSE) over the 24-year electric planning horizon, from 2022 to 2045, and 20-year natural gas planning horizon, from 2022 to 2041. This conservation potential assessment (CPA), commissioned by PSE as part of its integrated resource planning (IRP) process, is intended to identify DSR potential from the perspectives of energy efficiency, demand response, and distributed generation (including solar photovoltaics and combined heat and power). The results of this assessment will help PSE identify cost-effective DSR and design future programming.

This study builds upon previous assessments of DSR resources in PSE's territory. It incorporates the latest baseline and DSR data from primary and secondary sources and is informed by the work of other entities in the region, such as the Northwest Power and Conservation Council (Council), the Northwest Regional Technical Forum (RTF), and the Northwest Energy Efficiency Alliance (NEEA). The methods used to evaluate the technical and achievable technical potential draw upon best utility industry practices and remain consistent with the methodology used by the Council in its assessment of regional conservation potentials in its most recently approved Seventh Northwest Conservation and Electric Power Plan (Seventh Plan). In addition, this work is also consistent with the draft 2021 Northwest Conservation and Electric Power Plan (2021 Plan) supply curves work that was under development as this assessment was being updated.

Scope of the Analysis and Approach

Energy Efficiency and Combined Heat and Power

The energy efficiency analysis included estimates of the technical and achievable technical potential for more than 400 unique electric and natural gas energy efficiency measures. Cadmus relied on PSE program data, RTF analysis, The Council's draft 2021 Plan and Seventh Plan analyses, and regional stock assessments to determine the savings, costs, and applicability for each measure. We incorporated feedback from PSE staff and regional stakeholders on the list of measures and measure assumptions.

Cadmus prepared 24-year forecasts of potential electric energy, peak demand, and a 20-year natural gas forecast of energy savings for each energy efficiency measure using a units-based method consistent with the Council's approach for its most recently approved plan (the Seventh Plan). The assessment considers multiple vintages (new and existing), distinguishes between lost opportunity and replace-on-burnout measures and accounts for building energy codes as well as future state and federal equipment standards. Achievable technical potential estimates use assumptions that are consistent with the Council's draft 2021 Plan: 85-100% of technical potential is achieved over the 24-year electric and 20-year natural gas study horizons, and adoption curves are derived from the Council's draft 2021 Plan ramp rates.

The combined heat and power (CHP) analysis identifies potential generation from nonrenewable and renewable CHP technologies in large commercial and industrial facilities. We derived estimates of CHP technical potential using generation and applicability data for reciprocating engines, microturbines, gas turbines, industrial biomass, and biogas. We determined achievable potential for these technologies using American Council for an Energy-Efficient Economy (ACEEE) CHP favorability data and an analysis of the U.S. Department of Energy (DOE) CHP Installation Database.

Demand Response

Demand response programmatic options seek to help reduce peak demand during system emergencies or periods of extreme market prices and to promote improved system reliability. Cadmus' analysis focused on program options that include residential direct load control (DLC) for space heat, room heat, water heat, and nonresidential load curtailment. These strategies include price- and incentive-based options for all major customer segments and end uses in PSE's service territory.

To estimate demand response potentials, this study applied a hybrid, top-down, and bottom-up approach that began by using utility system loads, disaggregated into sector, segment, and applicable end uses. For each program, we first assessed potential impacts at the end-use level then aggregated these to obtain estimates of technical potentials. This allowed us to apply market factors, such as likely program and event participation, to technical potentials to obtain estimates of market potentials.

A detailed discussion of the demand response potential is covered under section 2 of this report.

Distributed Solar Photovoltaics

The solar PV analysis uses power density forecasts and estimates of the total available roof area for solar PV to develop forecasts of nameplate capacity. Solar PV achievable potential was determined using a bass diffusion equation that incorporates data on the adoption of customer driven solar PV in PSE's service territory and future price and PV efficiency forecasts to estimate customer payback over time.

A detailed discussion of the distributed solar potential is covered under section 3 of this report.

Summary of Results

Table 1 shows the technical and achievable potential for each resource considered in this study. Electric DSRs represent nearly 608 average megawatts (aMW) of achievable technical potential and could produce approximately 1,192 MW of winter peak savings. Energy efficiency has the highest energy-savings potential, with 600 aMW of cumulative achievable technical potential by 2045. Cadmus identified natural gas cumulative achievable technical potential of 174 million therms. All estimates of potential in this report are presented at the generator, meaning they include line losses.

Table 1. Summary of Energy and Demand Savings Potential, Cumulative 2045

Resource	Energy (aMW/Million Therms)		Winter Coincident Peak Capacity (MW)	
	Technical Potential	Achievable Technical Potential	Technical Potential	Achievable Technical Potential
Electric Resources				
Energy Efficiency	706	600	1,127	958

Resource	Energy (aMW/Million Therms)		Winter Coincident Peak Capacity (MW)	
	Technical Potential	Achievable Technical Potential	Technical Potential	Achievable Technical Potential
Demand Response	N/A	N/A	N/A	226
Combined Heat and Power	200	8	200	8
Electric Resources Total	**906**	**608**	**1,327**	**1,192**
Natural Gas Resources				
Energy Efficiency	204	174	N/A	N/A

Figure 1. and Figure 2. present the respective electric and natural gas achievable potential forecasts. More savings are achieved for both fuels in the first 10 years of the study (2022 through 2031) than in the remaining years because the study assumes all discretionary measure potential savings (i.e., measures that retrofit existing homes and businesses) are acquired in the first 10 years. In the remaining years, additional savings come from lost opportunity measures, such as equipment replacement and new construction.

Figure 1. Electric Achievable Technical Potential Forecast, Cumulative 2022 - 2045

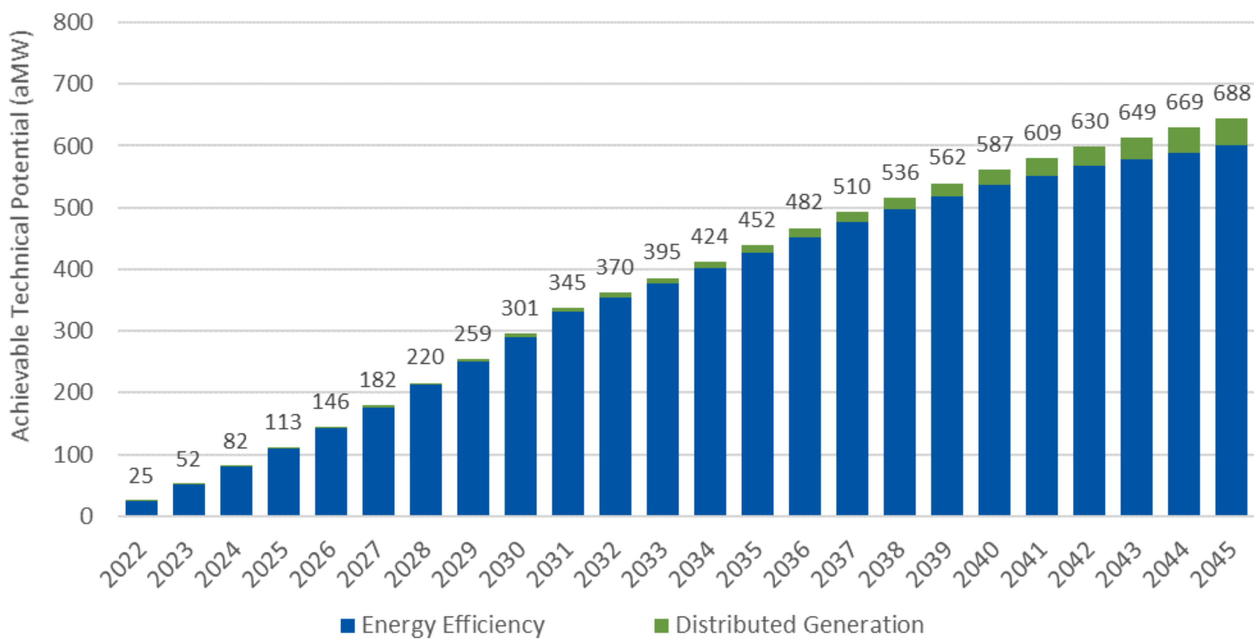
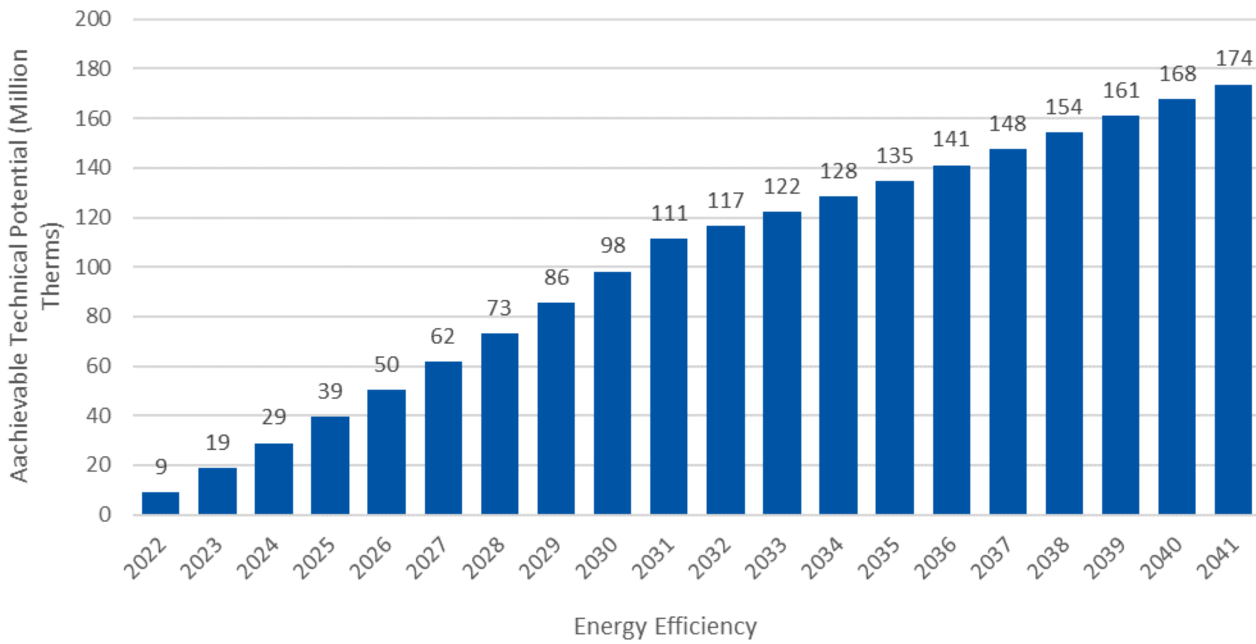


Figure 2. Natural Gas Achievable Potential Forecast, Cumulative 2022 - 2041



Energy Efficiency

The total achievable technical potential for electricity across all sectors is 600 aMW (Table 2). If the 24-year achievable potential is realized it will produce a load reduction equivalent to 18% of PSE's 2045 baseline electric sales. Approximately 56% of this potential is in the residential sector, 42% in the commercial sector, and the remaining 2% in the industrial sector.

Table 2. Electric Energy Efficiency by Sector, Cumulative 2045

Sector	2045 Baseline Sales (aMW)	Achievable Technical Potential	
		aMW	Percentage of Baseline Sales
Residential	1,846	339	18%
Commercial	1,339	250	19%
Industrial	122	10	8%
Total	**3,306**	**600**	**18%**

Cadmus identified approximately 174 million therms of natural gas energy efficiency achievable potential, with 147 million of these savings in the residential sector (Table 3). Overall natural gas achievable potential is equivalent to 15% of PSE's forecasted natural gas sales in 2041. Natural gas potentials were forecast out to 2041 while electricity was forecasted to 2045.

Table 3. Natural Gas Energy Efficiency by Sector, Cumulative 2041

Sector	2041 Baseline Sales (MM Therms)	Achievable Technical Potential	
		MM Therms	Percentage of Baseline Sales
Residential	757	147	19%

Sector	2041 Baseline Sales (MM Therms)	Achievable Technical Potential	
		MM Therms	Percentage of Baseline Sales
Commercial	362	25	7%
Industrial	22	2	8%
Total	**1,141**	**174**	**15%**

Comparison to 2019 CPA – Energy Efficiency

The 2021 energy efficiency analysis incorporates these changes since the completion of PSE's most recent previous CPA in 2019:

- Uses PSE's most recent F2020 Demand Forecast of energy and customers.
- Incorporates assumptions for savings, cost, and measure lives derived from PSE's 2020 measure business cases and RTF unit energy savings (UES) workbook updates as of January 31, 2020
- Uses the most recent PSE-specific and regional stock assessments to determine saturations and applicability, including PSE's 2017 Residential Characteristics Study (RCS), NEEA's 2018 Residential Building Stock Assessment (RBSA), and NEEA's 2014 Commercial Building Stock Assessment (CBSA)
- Accounts for changes to the Washington State Energy Code (WSEC) and Seattle Building Energy Code as well as recent changes to federal and Washington state equipment standards, including products added to state standards by legislation – House Bill 1444 (H.B. 1444) – passed in 2019 and signed into law by Governor Inslee
- Considers the impact of the Washington State Energy Performance Standard (HB1257) on commercial buildings by accelerating ramp rates for some commercial measures

Table 4 compares the 20-year achievable technical potential, expressed as a percentage of baseline sales, identified in the 2021 and 2019 CPAs. Overall, the 2021 CPA identified lower electric (-20%) and slightly lower natural gas (-2%) achievable technical potential.

Table 4. Energy Efficiency Comparison to Past CPAs

Study	20-Year Achievable Technical Potential (Percent of Sales)			Total Achievable Technical Potential (aMW and Million Therms)
	Residential	Commercial	Industrial	
Electric Resources				
2021 IRP	18%	18%	8%	552
2019 IRP	21%	16%	26%	692
Natural Gas Resources				
2021 IRP	19%	7%	8%	174
2019 IRP	20%	8%	17%	177

*This table compares 20-year results from 2021 CPA to the 2019 CPA. The 2021 CPA total electric achievable technical potential differs from the amount shown in Table 2, which presents the full 24-year electric potential study results

The following contribute to the significant decrease in electric energy efficiency potential:

- Exclusion of embedded data center measures which previously contributed 46 aMW of achievable potential in the 2019 CPA
- Updated forecast assumptions of the indoor cannabis market, previously assumed to grow at a rate of 3% per year within PSE's service territory, led to a 25 aMW reduction in potential (compared to the 2019 CPA)
- Incorporation of updated commercial LED lighting technology baselines, based on the Council's draft 2021 plan commercial lighting supply curves, which led to a 25 aMW reduction in potential (compared to the 2019 CPA)
- Re-classification of some industrial customers to the commercial sector
- Reductions in achievable potential due to the 2019 state equipment standards updates (HB 1444)

Combined Heat and Power

Table 5 illustrates the 24-year cumulative achievable technical potential from CHP technologies. Overall, Cadmus identified 7.8 aMW of potential from renewable and nonrenewable technologies.

Table 5. Combined Heat and Power Achievable Potential Summary, Cumulative 2045

CHP Type	Total Achievable Technical Potential (aMW)
Reciprocating Engine	4.0
Gas Turbine	1.1
Microturbine	1.0
Biogas (Anaerobic Digesters)	1.3
Industrial Biomass	0.4
Total	**7.8**

Comparison to 2019 CPA – CHP

Table 6 compares the 24-year cumulative CHP potential identified in the 2019 CPA to the 20-year cumulative CHP potential in the 2021 CPA. The decrease in CHP potential results from a lower, long-term electric commercial customer forecast compared to the 2019 CPA and re-allocation of commercial customer eligibility requirements across commercial building types.

Table 6. CHP Comparison to the 2019 IRP, Cumulative 2045 aMW

CHP Potential	2021 IRP	2019 IRP
Total	7.8	18

Demand Response

Table 7 presents the winter and summer peak achievable potential for demand response programs. Total 24-year winter demand response potential is 229 MW, which is equivalent to nearly a 4.5% reduction in PSE's forecasted 2045 winter peak.

Table 7. Demand Response Potential by Program, 2045

Product	Winter Achievable Potential (MW)	Percent of PSE System Peak (Winter)	Summer Achievable Potential (MW)	Percent of PSE System Peak (Summer)
Residential Critical Peak Pricing	66	1.3%	40	1.0%
Residential DLC Space Heating	53	1.1%	n/a	n/a
Residential DLC Space Cooling	n/a	n/a	55	1.4%
Residential DLC Water Heating	69	1.2%	69	1.7%
Commercial DLC Space Heating	12	0.2%	n/a	n/a
Commercial DLC Space Cooling	n/a	n/a	27	0.7%
Commercial and Industrial Curtailment	6	0.1%	8	0.2%
Commercial Critical Peak Pricing	2	< 0.1%	5	0.1%
Residential Electric Vehicle Service Equipment	9	0.2%	9	0.2%
Residential Behavioral	9	0.2%	5	0.1%
Total	**226**	**4.5%**	**218**	**5.4%**

Comparison to 2019 CPA – Winter Demand Response

Table 8 compares the demand response potential identified in the 2021 and 2019 CPAs, by sector. Overall, the 2021 CPA identified 7 MW less winter peak potential compared to 2019. Even though the total winter peak potential of 2021 and 2019 are comparable, it can be seen that the segment share of that potential has changed. Several factors contributed to higher residential demand response potential, including updates to end-use saturations for water heat, revised peak impacts from recent demand response evaluations, and the inclusion of new products (for instance, the 2021 CPA considered a residential behavioral product that was not considered in the 2019 study).

Table 8. Demand Response Achievable Potential Comparison of 2019 CPA and 2017 CPA

Sector	2021 CPA (MW)	2019 CPA (MW)	2017 CPA (MW)
Residential	206	180	109
Commercial and Industrial	20	53	79
Total	**226**	**233**	**188**

The following contribute to the decrease in commercial and industrial demand response potential:

- Revisions to customer participation assumptions for commercial and industrial demand curtailment, consistent with the Council's draft 2021 Plan demand response supply curves
- Updates to per event demand impacts for commercial and industrial demand curtailment, consistent with the Council's draft 2021 Plan demand response supply curves

Distributed Solar PV and Comparison to the 2019 CPA

Cadmus identified 87 MW of solar PV nameplate capacity achievable potential in the residential sector and 249 MW in the commercial sector (336 MW total). This is higher than the 231 MW of solar PV achievable potential identified in the 2019 assessment (Table 9) and is equivalent to 9.4 aMW and 26.8 aMW of cumulative achievable energy potential for the residential, and commercial sectors, respectively. The increase in solar PV potential is primarily the result of lower estimated costs for residential and commercial systems due to updated data sources.

Table 9. Solar PV Achievable Potential Comparison to 2019 IRP

Sector	Achievable Potential (MW)	
	2021 IRP	2019 IRP
Residential	87	34
Commercial and Industrial	249	196
Total	**336**	**231**

Incorporating DSR into PSE's IRP

The achievable technical potentials for EE and CHP shown above have been grouped by the levelized cost of conserved energy for inclusion in PSE's IRP model. These costs have been calculated over a 24-year program life for electric resources and over a 20-year program life for gas resources; the *Calculate Levelized Costs* section provides additional detail on the levelized cost methodology. Bundling resources into a number of distinct cost groups allows the model to select the optimal amount of annual DSR, based on expected load growth, energy prices, and other factors.

Cadmus spread the annual savings estimates over 8760-hour load shapes to produce hourly DSR bundles. In addition, we assumed savings are gradually acquired over the year, as opposed to instantly on the first day of January. PSE provided intra-year DSR acquisition schedules, which we used to ramp hourly savings across months. Figure 3. shows the annual cumulative combined potential for energy efficiency and combined heat and power by each cost bundle considered in PSE's 2021 IRP. Figure 4. shows annual DSR bundles for natural gas energy efficiency.

Figure 3. Electric Supply Curve – Cumulative 24-Year Achievable Potential

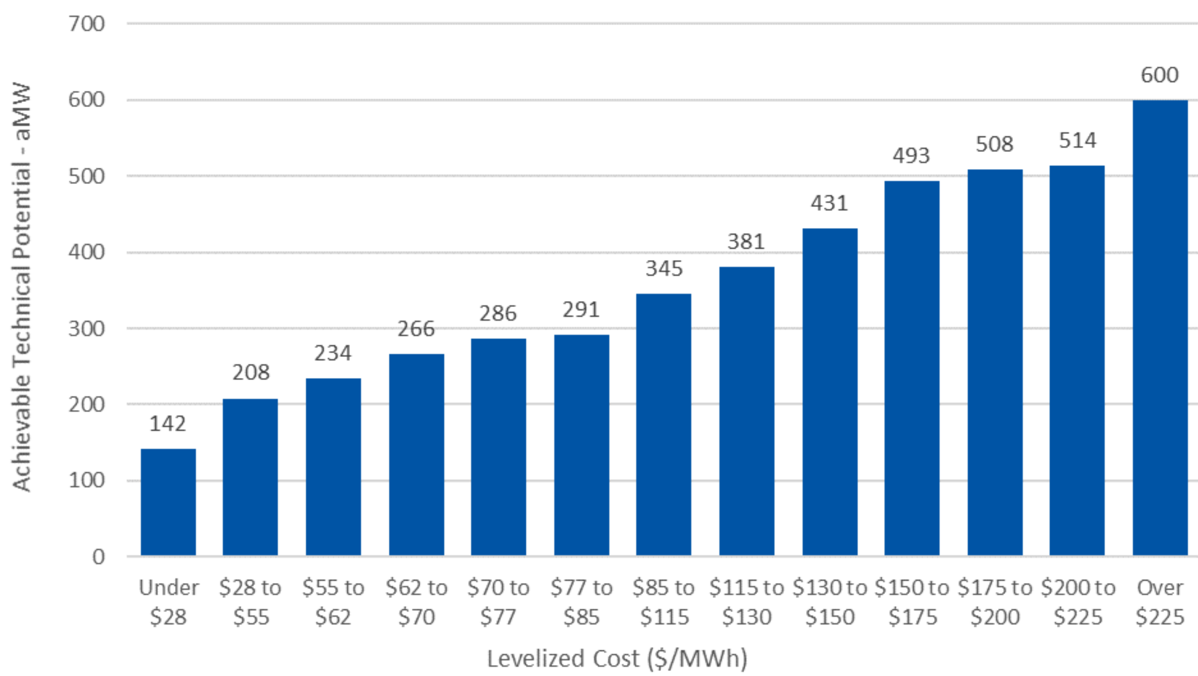
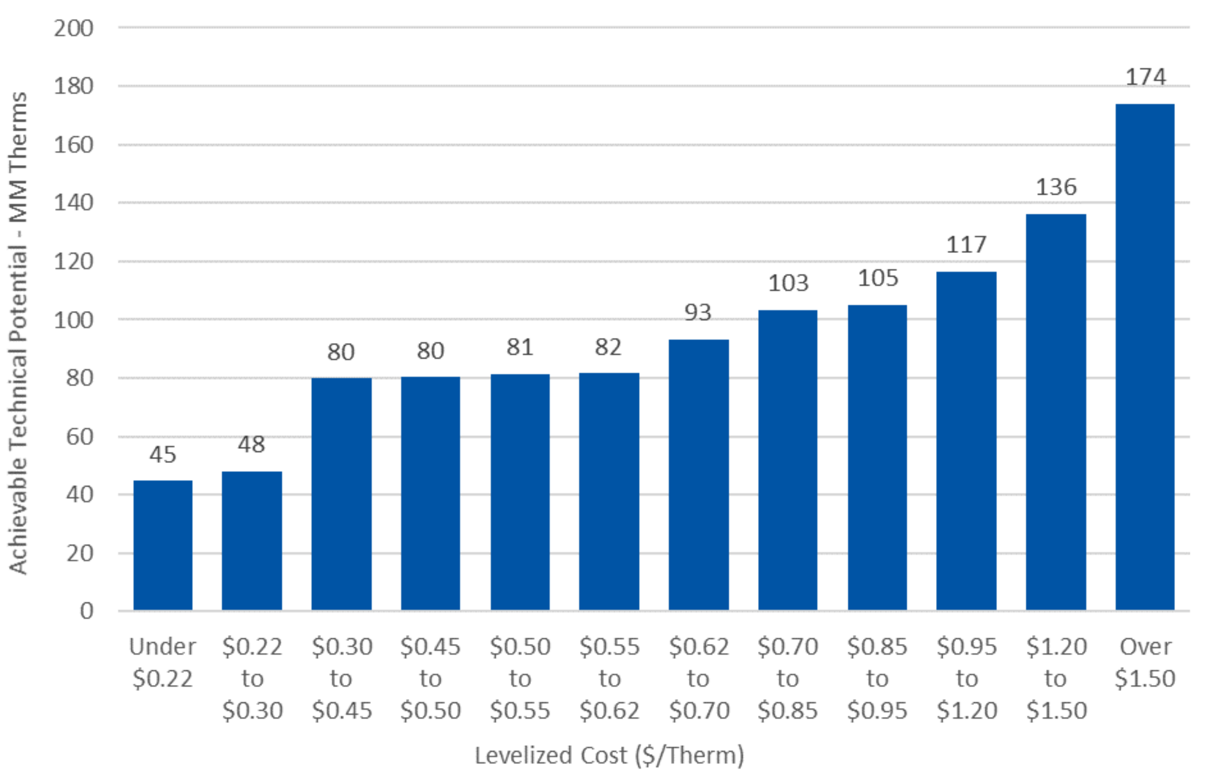


Figure 4. Natural Gas Supply Curve – Cumulative 20-Year Achievable Potential



Similarly, Cadmus spread the annual savings estimates for distributed solar over 8760-hour load shapes to produce hourly DSR bundles. These savings were input without any costs in the IRP, as these programs are customer driven and the IRP does not determine the cost-effective potential; the IRP accounts for the reductions to the demand forecast only.

Finally, the demand response programs are a capacity-only resource and were grouped by program and annual capacity. The capacities are cumulated over each year of the study, and the program costs are input as annual, incremental costs associated with the peak demand reductions that are added in a particular year.

Organization of This Report

This report has been organized in three main sections, and an appendix:

- Energy efficiency and combined heat and power
- Demand response, and
- Distributed solar PV
- Appendix A. IRP Sensitivities

Section 1. Energy Efficiency and Combined Heat and Power

This section describes Cadmus' methodology for estimating demand-side resources (DSR) potential in PSE's service territory between 2022 and 2045 and for developing supply curves for modeling DSR in PSE's integrated resource planning (IRP). We describe the calculations for technical and achievable technical potential, identify the data sources for components of these calculations, and discuss key global assumptions. Estimating DSR potential involves analyzing many conservation measures across many sectors, with each measure requiring nuanced analysis. This section does not describe the detailed approach for estimating a specific measure's unit energy savings (UES) or cost, but it does show the general calculations that were used for nearly all measures.

Overview of Technical and Achievable Potential

Cadmus assessed two types of potential—technical and achievable technical. PSE will determine a third potential—achievable economic—through the IRP's optimization modeling. The three types of potential are described as follows:

- ***Technical potential*** assumes that all technically feasible resource opportunities may be captured, regardless of their costs or other market barriers. It represents the total DSR potential in PSE's service territory, after accounting for purely technical constraints.
- ***Achievable technical potential*** is the portion of technical potential that is assumed to be achievable during the study's forecast, regardless of the acquisition mechanism. For example, savings may be acquired through utility programs, improved codes and standards, and market transformation.
- ***Achievable economic potential*** is the portion of achievable technical portion determined to be cost-effective by the IRP's optimization modeling, in which either bundles or individual DSR measures are selected based on cost and savings. The cumulative potential for these selected bundles constitutes achievable economic potential.

Cadmus provided PSE with forecasts of achievable technical potential, which were then entered as variables in the IRP's optimization model to determine achievable economic potential.

Figure 5. illustrates the three types of energy efficiency potential.

Figure 5. Types of Energy Efficiency Potential

The timing of resource availability is also a key consideration in determining conservation potential. There are two distinct categories of resources:

- ***Discretionary resources*** are retrofit opportunities in existing facilities that, theoretically, are available at any point over the study period. Discretionary resources are also referred to as retrofit measures. Examples include weatherization and shell upgrades, economizer optimization, and low-flow showerheads.
- ***Lost-opportunity resources***, such as conservation opportunities in new construction and replacements of equipment upon failure (natural replacement), are nondiscretionary. These resources become available according to economic and technical factors beyond a program administrator's control. Examples of natural replacement measures include HVAC equipment, water heaters, appliances, and replace-on-burnout lighting fixtures.

Cadmus used a units-based approach to forecast energy efficiency potential in the residential and commercial sectors. This approach involved first estimating the number of units of an energy efficiency measure that are likely to be installed in each year then multiplying these unit forecasts by the measure's UES.

For the industrial sector, Cadmus used a top-down method calculating technical potential as a percentage reduction to the baseline industrial forecast. Baseline end-use loads are first estimated for each industrial segment, then the potential is calculated using estimates of each measures' end-use percentage savings.

Steps for Estimating Energy Efficiency Potential

Cadmus followed this series of steps, described in detail below this list, to estimate energy efficiency potential:

1. ***Market segmentation.*** This involved identifying the sectors and segments for estimating energy efficiency potential. Segmentation accounts for variation across different parts of PSE's service territory and across different applications of energy efficiency measures.
2. ***Develop efficiency measure dataset.*** This required research into viable energy efficiency measures that can be installed in each segment. The description for this step below includes the components and data sources for estimating measure savings, costs, applicability factors, lifetimes, baseline assumptions, and the treatment of federal standards.
3. ***Develop unit forecasts.*** Unit forecasts vary by sector—number of homes for residential, square footage of floor space for commercial, energy for industrial, and poles for street lighting—and reflect the number of units that could be installed for each measure. Cadmus developed sector-specific methodologies to determine the number of units.
4. ***Calculate levelized costs.*** IRP modeling requires levelized costs for each measure, and in aggregate, to compare energy conservation to supply-side resources. The components and assumptions for the levelized-cost calculations are discussed below.
5. ***Forecast technical potential.*** Technical potential forecasts rely on the sector-specific unit forecasts and the measure data compiled from prior steps. The description below presents the general equation we used for calculating technical potential.
6. ***Forecast achievable technical potential.*** Achievable technical potential forecasts use an equation like the one we used to determine technical potential forecasts, with additional terms (described below) to account for market barriers and ramping.
7. ***Develop IRP inputs.*** Forecasts of achievable technical potential were bundled by levelized costs, so PSE's IRP modelers can consider energy efficiency as a resource within the IRP.

Figure 6. provides a general overview of the process and inputs required to estimate potential and develop conservation supply curves.

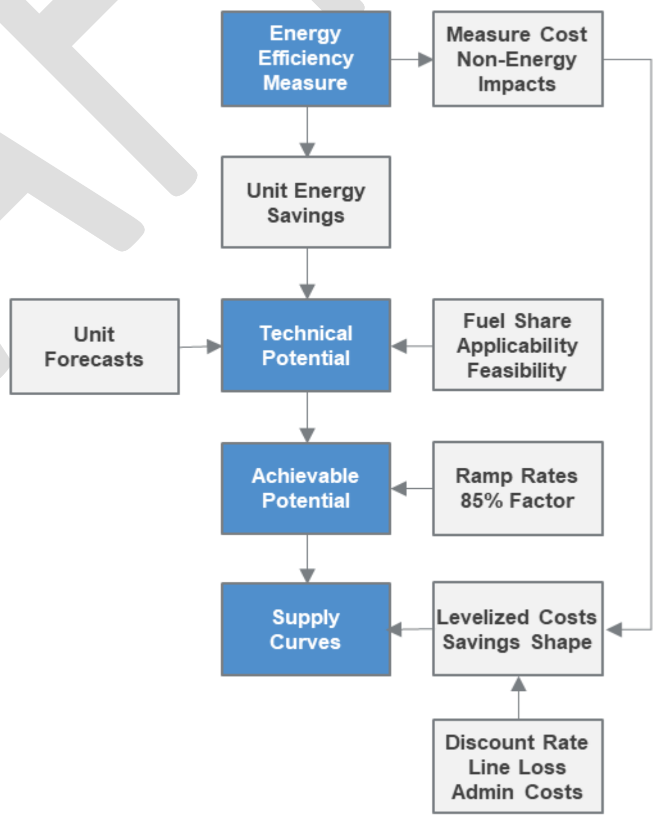


Figure 6. Overview of Energy Efficiency Methodology

Segmentation

Market segmentation involves first dividing PSE's gas and electric service territories into sectors and market segments. Careful segmentation accounts for variation in building characteristics and savings across the service territory. To the extent possible, energy efficiency measure inputs reflect primary data, such as the NEEA's 2014 Commercial Building Stock Assessment (CBSA), the 2018 Residential Building Stock Assessment (RBSA), and PSE's Residential Characteristics Study (RCS).

Considering the benefits and drawbacks of different segmentation approaches, Cadmus identified three parameters that produce meaningful and robust estimates:

- ***Service territories and fuel.*** PSE's respective natural gas and electric service territories
- ***Sector.*** Residential, commercial, industrial, and street lighting
- ***Industries and building types.*** Three residential (with the corresponding low income (LI)) segments, 19 commercial, 19 industrial, and one street lighting segments

Table 10 lists the segments modeled for each sector.

Table 10. Segments Modeled

Residential	Commercial	Industrial
Single Family	Large Office	Mechanical Pulp
Multifamily	Medium Office	Kraft Pulp
Manufactured	Small Office	Paper
Multifamily Low Income	Extra Large Retail	Foundries
Manufactured Low Income	Large Retail	Food - Frozen
Single Family Low Income	Medium Retail	Food - Other
	Small Retail	Wood - Lumber
	School K-12	Wood - Panel
	University	Wood - Other
	Warehouse	Sugar
	Supermarket	Hi Tech - Chip Fabrication
	Mini-Mart	Hi Tech - Silicon
	Restaurant	Metal Fabrication
	Lodging	Transportation Equipment
	Hospital	Refinery
	Residential Care	Cold Storage
	Assembly	Fruit Storage
	Other	Chemical
	Indoor Agriculture	Miscellaneous Manufacturing
	Wastewater	Streetlighting

Energy Efficiency Measure Characterization

Overview and Components

Cadmus compiled energy efficiency datasets that include the UES, costs, measure lives, non-energy impacts, and applicability factors for each energy conservation measure. These datasets include several details for each measure permutation:

- ***Unit energy savings (UES).*** UES are a conservation measure's annual per-unit kilowatt-hour and/or therm savings. Cadmus relied on UES values from PSE's internal measure business cases, RTF UES workbooks, the Seventh Plan, and a limited set of draft 2021 Plan supply curves
- ***Costs and non-energy impacts.*** Costs include the incremental per-unit equipment (capital), labor, annual incremental operations and maintenance (O&M), and periodic (or avoided periodic) re-installation costs associated with installing an energy efficiency measure. Non-energy impacts are the annual dollar savings per year associated with quantifiable non-energy benefits (such as water).
- ***Effective useful lives (EUL).*** EUL is the expected lifetime (in years) for an energy efficiency measure from PSE's measure business cases, the Seventh Plan, draft 2021 Plan, or RTF.
- ***Applicability factors.*** Applicability factors reflect the percentage of installations that are technically feasible and the current saturation of an efficiency measure.
- ***End-use savings percentage (industrial only).*** The industrial sector's top-down approach to estimating potential requires assessments of the end-use percentage savings for each energy conservation measure. We relied on estimates included in the Council's Seventh Plan industrial tool for these values.
- ***Savings shape.*** We assigned an hourly savings shape to each measure, which we then used to disaggregate annual forecasts of potential into hourly estimates.

Accounting for Codes and Standards

Cadmus accounted for building energy codes and equipment standards by either embedding the impact of the standard in the UES estimate for above-standard equipment and/or by excluding measures that will be captured by the current code or standard. Cadmus accounted for the 2018 Washington State energy code (WSEC), effective November 1, 2020 for the residential and commercial sectors.

Table 11 and Table 12 list the federal and state electric and natural gas standards and their effective dates, respectively, that Cadmus considered. Most of these standards have either already been adopted or are scheduled to go into effect before this study's 2022 start date. Thus, equipment that meets the specifications of each respective standard were not included in estimates of energy efficiency potential. Generally, accounting for these standards reduced the total conservation potential.

Table 11. Electric Federal and State Standards

Equipment Electric Type	New Standard	Sectors Impacted	Study Effective Date
Clothes Washer (top loading)	Federal standard 2015	Residential	March 7, 2015
Clothes Washer (front loading)	Federal standard 2018	Residential	January 1, 2018
Clothes Washer (commercial sized)	1. Federal standard 2013	Nonresidential	1. January 8, 2013

Equipment Electric Type	New Standard	Sectors Impacted	Study Effective Date
	2. Federal standard 2018		2. January 1, 2018
Computers	State standard 2019	Nonresidential/Residential	January 1, 2021
Dehumidifier	1. Federal standard 2012	Residential	1. October 1, 2012
	2. Federal standard 2019		2. June 13, 2019
Dishwasher	Federal standard 2013	Residential	May 30, 2013
Dishwasher (commercial)	State standard 2019	Nonresidential	January 1, 2021
Dryer	Federal standard 2015	Residential	January 1, 2015
Uninterruptible (External) Power Supplies	1. Federal standard 2016	Nonresidential/Residential	1. February 10, 2016
	2. Federal standard 2017		2. July 1, 2017
	3. State standard 2019		3. January 1, 2021
Freezer	Federal standard 2014	Residential	September 15, 2014
Microwave	Federal standard 2016	Residential	June 17, 2016
Fryers and Steam Cookers	State standard 2019	Nonresidential	January 1, 2021
Refrigerator	Federal standard 2014	Residential	September 15, 2014
Automatic Commercial Ice Makers	1. Federal standard 2010	Nonresidential	1. January 1, 2010
	2. Federal standard 2018		2. January 28, 2018
Commercial Refrigeration Equipment (semi-vertical and vertical cases)	1. Federal standard 2010	Nonresidential	1. January 1, 2010
	2. Federal standard 2012		2. January 1, 2012
	3. Federal standard 2017		3. March 27, 2017
Vending Machine	1. Federal standard 2012	Nonresidential	1. August 31, 2012
	2. Federal standard 2019		2. January 8, 2019
Walk-in Cooler	1. Federal standard 2014	Nonresidential	1. August 4, 2014
Walk-in Freezer	2. Federal standard 2017		2. June 5, 2017
Central Air Conditioner	Federal standard 2015 (no change for Northern region)	Residential	January 1, 2015
Heat Pump (air source)	Federal standard 2015	Residential	January 1, 2015
Packaged Terminal Air Conditioner and Heat Pump	1. Federal standard 2012	Nonresidential	1. October 8, 2012
	2. Federal standard 2017		2. January 1, 2017
Room Air Conditioner	Federal standard 2014	Residential	June 1, 2014
Single Package Vertical Air Conditioner and Heat Pump	1. Federal standard 2010 (phased in over six years)	Nonresidential	1. January 1, 2010
	2. Federal standard 2019		2. September 23, 2019
Small, Large, and Very Large Commercial Package Air Conditioner and Heat Pump	1. Federal standard 2010	Nonresidential	1. January 1, 2010
	2. Federal standard 2018		2. January 1, 2018
	3. Federal standard 2023		3. January 1, 2023
Fluorescent Lamp Ballast	Federal standard 2014	Nonresidential	November 14, 2014
General Service Fluorescent Lamp	1. Federal standard 2012	Nonresidential	1. July 14, 2012
	2. Federal standard 2018		2. January 26, 2018
Lighting General Service and Specialty Lamp	State standard 2019	Nonresidential/Residential	January 1, 2021
Metal Halide Lamp Fixture	Federal standard 2017	Nonresidential	February 10, 2017
Electric Motor (small)	Federal standard 2015	Nonresidential	March 9, 2015
Electric Motor	1. Federal standard 2010	Nonresidential	1. December 19, 2010
	2. Federal standard 2016		2. June 1, 2016
Furnace Fan	Federal standard 2019	Residential	July 3, 2019
Pump	Federal standard 2020	Nonresidential	January 27, 2020
Pre-Rinse Spray Valve	Federal standard 2019	Nonresidential	January 28, 2019
Showerhead	State standard 2019	Nonresidential/Residential	January 1, 2021
Water Heater > 55 Gallons	Federal standard 2015	Nonresidential/Residential	April 16, 2015
Water Heater ≤ 55 Gallons	Federal standard 2015	Nonresidential/Residential	April 16, 2015

Table 12. Natural Gas Federal and State Standards

Equipment Natural Gas Type	New Standard	Sectors Impacted	Standard Effective Date
Boiler (residential sized)	1. Federal standard 2012	Nonresidential/ Residential	1. September 1, 2012
	2. Federal standard 2021		2. January 15, 2021
Clothes Washer (top loading)	Federal standard 2015	Residential	March 7, 2015
Clothes Washer (front loading)	Federal standard 2018	Residential	January 1, 2018
Clothes Washer (commercial sized)	1. Federal standard 2013	Nonresidential	1. January 8, 2013
	2. Federal standard 2018		2. January 1, 2018
Dishwasher	Federal standard 2013	Residential	May 30, 2013
Dryer	Federal standard 2015	Residential	January 1, 2015
Furnace (residential sized)	Federal standard 2015	Nonresidential/ Residential	November 19, 2015
Pool Heater	Federal standard 2013	Residential	April 16, 2013
Pre-Rinse Spray Valve	Federal standard 2019	Nonresidential	January 28, 2019
Showerhead	State standard 2019	Nonresidential/ Residential	January 1, 2021
Water Heater > 55 Gallons	Federal standard 2015	Nonresidential/ Residential	April 16, 2015
Water Heater ≤ 55 Gallons	Federal standard 2015	Nonresidential/ Residential	April 16, 2015

Baseline Units Forecast

General Approach

Cadmus developed a 24-year forecast (2022 through 2045) of the number of electric units and a 20-year forecast (2022 through 2041) of the number of gas units that could feasibly be installed for each permutation of each energy efficiency measure researched in the previous step. Separate unit forecasts were developed for two types of lost opportunity measures (natural replacement and new construction) and one type of discretionary measures (retrofit):

- ***Natural replacement (lost opportunity) measures*** are installed when the equipment it replaces reaches the end of its EUL. Examples include appliances (such as clothes washers and refrigerators) and HVAC equipment (such as heat pumps and chillers).
- ***New construction (lost opportunity) measures*** are applied to homes and buildings that will be constructed over the study forecast. The unit forecast for new construction is driven by anticipated new home and new commercial construction, which we derived from utility customer forecasts and draft 2021 Plan regional forecasts.
- ***Retrofit (discretionary) measures*** encompass existing equipment or building upgrades that can theoretically be completed any time over the study forecast. Unlike natural replacement measures, the timing of retrofit savings is not determined by turnover rates. Examples of retrofit measures include weatherization and controls.

To determine measure-specific unit forecasts (used to estimate technical potential), four factors were considered:

- ***Sector unit forecasts*** are estimates of the number of homes (residential) or square footage of floor space (commercial) derived from PSE's customer database and load forecast data.

- ***Measure saturations (units per sector unit)*** are estimates of the number of units per sector unit (per home or per square foot) in PSE's natural gas and electric service territories. Where possible, Cadmus calculated these using data from the PSE 2017 RCS, CBSA, and RBSA.
- ***Applicability factors (technical feasibility percentage and measure competition share)*** are the percentage of homes or buildings that can feasibly receive the measure and the percentage of eligible installations, after accounting for competition with similar measures.
- ***Turnover rates (for natural replacement measures)*** are used to determine the percentage of units that can be installed in each year for natural replacement measures. The turnover rate equals 1 divided by the measure EUL.

Figure 7 illustrates the general equation Cadmus used to determine the number of units for each measure over the study forecast horizon. By default, the turnover rate for retrofit and new construction measures is 100%. (Turnover is not accounted for in these permutations.)

Figure 7. Unit Forecast Equation

To determine unit forecasts, Cadmus relied on data that represent PSE's service territories, as shown in Table 13. Following the table, we describe our approach for developing unit forecasts in each sector.

Table 13. Unit Forecast Components and Data Sources

Component	Data Source
Sector Units	PSE and U.S. Energy Information Administration (EIA) 861 data; U.S. Census Bureau American Community Survey; PSE RCS sample design file; PSE CIS data
Saturation	PSE 2017 RCS; Regional stock assessments (RBSA and CBSA)
Applicability Factor	PSE 2017 RCS; Regional stock assessments (RBSA and CBSA)
Turnover Rate	PSE, RTF, draft 2021 Plan, and Seventh Plan measure workbooks

Calculate Levelized Costs

Identified potential is grouped by levelized cost over a 24-year study horizon for electric resources and a 20-year horizon for natural gas resources, which allows PSE's IRP model to pick the optimal DSR amount, given various assumptions regarding future resource requirements and costs. The 24-year electric levelized-cost and 20-year natural gas levelized-cost calculations incorporate numerous factors, which are consistent with the Council's methodology and shown in Table 14.

Table 14. Levelized Cost Components

Type	Component
Costs	Incremental Measure Cost
	Incremental O&M Cost*
	Administrative Adder
Benefits	Present Value of Non-Energy Benefits
	Present Value of T&D Deferrals**
	Conservation Credit
	Secondary Energy Benefits

*Some measures may have a reduction in O&M costs, which is a benefit in the levelized cost calculation.
**For natural gas, this includes the deferred gas distribution benefits

In addition to the upfront capital cost and annual energy savings, the levelized-cost calculation incorporates several other factors, consistent with the Council's methodology:

- ***Incremental measure cost.*** This study considers the costs required to sustain savings over a 24-year horizon, including reinstallation costs for measures with useful lives less than 24 years. If a measure's useful life extends beyond the end of the 24-year study, Cadmus incorporates an end effect that treats the levelized cost of that measure over its EUL as an annual reinstallation cost for the remainder of the 24-year period.[1,2,3]

  For example, Figure 8 shows the timing of initial and reinstallation costs for an electric measure with a ten-year lifetime in context with the 24-year electric study horizon. The measure's final lifetime in this study ends after the study horizon, so the final four years (Year 21 through Year 24) are treated differently by leveling measure costs over its ten-year useful life and treating these as annual reinstallation costs.

Figure 8. Illustration of Capital and Reinstallation Cost Treatment

	Year																							
Component	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Initial Capital Cost																								
Re-Installation Cost																					End Effect			

- ***Incremental operations and maintenance (O&M) benefits or costs.*** As with incremental measure costs, O&M costs are considered annually over the 24-year horizon. The present value

[1] In this context, EUL refers to levelizing over the measure's useful life. This is equivalent to spreading incremental measure costs over its EUL in equal payments assuming a discount rate equal to PSE's weighted average cost of capital (6.80%).

[2] This method is applied both to measures with a useful life of greater than 24 years and measures with a useful life that extends beyond study horizon at time of reinstallation.

[3] This method also applies to the 20-year natural gas study horizon.

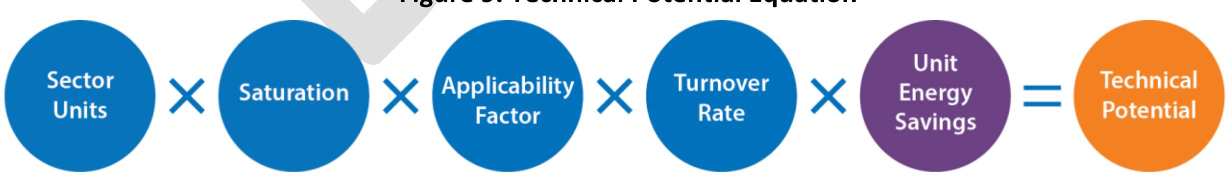
is used to adjust the levelized cost upward for measures with costs above baseline technologies and downward for measures that decrease O&M costs.

- ***Administrative adder.*** Cadmus assumed a program administrative cost equal to 20% of incremental measure costs for electric and gas measures across all sectors.
- ***Non-energy benefits.*** These benefits are treated as a reduction in levelized costs for measures that save resources, such as water or detergent. For example, the value of reduced water consumption due to the installation of a low-flow showerhead reduces the levelized cost of that measure.
- ***The regional 10% conservation credit, capacity benefits during PSE's system peak, and transmission and distribution (T&D) deferrals.*** These are similarly treated as reductions in levelized cost for electric measures. The addition of this credit per the Northwest Power Act is consistent with Council's methodology and is effectively an adder to account for unquantified external benefits of conservation when compared to other resources.[4]
- ***Secondary energy benefits.*** These benefits are treated as a reduction in levelized costs for measures that save energy on secondary fuels. This treatment is necessitated by Cadmus' end-use approach to estimating technical potential. For example, consider the cost for R-60 ceiling insulation for a home with a gas furnace and an electric cooling system. For the gas furnace end use, Cadmus considers the energy savings that R-60 insulation produces for electric cooling systems, conditioned on the presence of a gas furnace, as a secondary benefit that reduces the levelized cost of the measure. This adjustment impacts only the measure's levelized costs; the magnitude of energy savings for the R-60 measure on the gas supply curve is not impacted by considering secondary energy benefits.

Forecast Technical Potential

After compiling UES estimates and developing unit forecasts for each permutation of each energy efficiency measure, Cadmus multiplied the two to create 24-year forecasts of technical potential beginning in 2022. Figure 9 shows the equation for calculating technical potential. Blue components make up the measure unit calculation (shown previously in Figure 7.).

Figure 9. Technical Potential Equation



[4] Northwest Power & Conservation Council. January 1, 2010. "Northwest Power Act." http://www.nwcouncil.org/library/poweract/default.htm.

Forecast Achievable Potential

Achievable technical potential equals the product of a unit forecast, the measure UES, the maximum achievability factor, and ramp rate factors (Figure 10). Blue components are a part of the measure unit calculation. The purple component is a part of the technical potential calculation. The blue, purple, and orange components make up the achievable potential calculation.

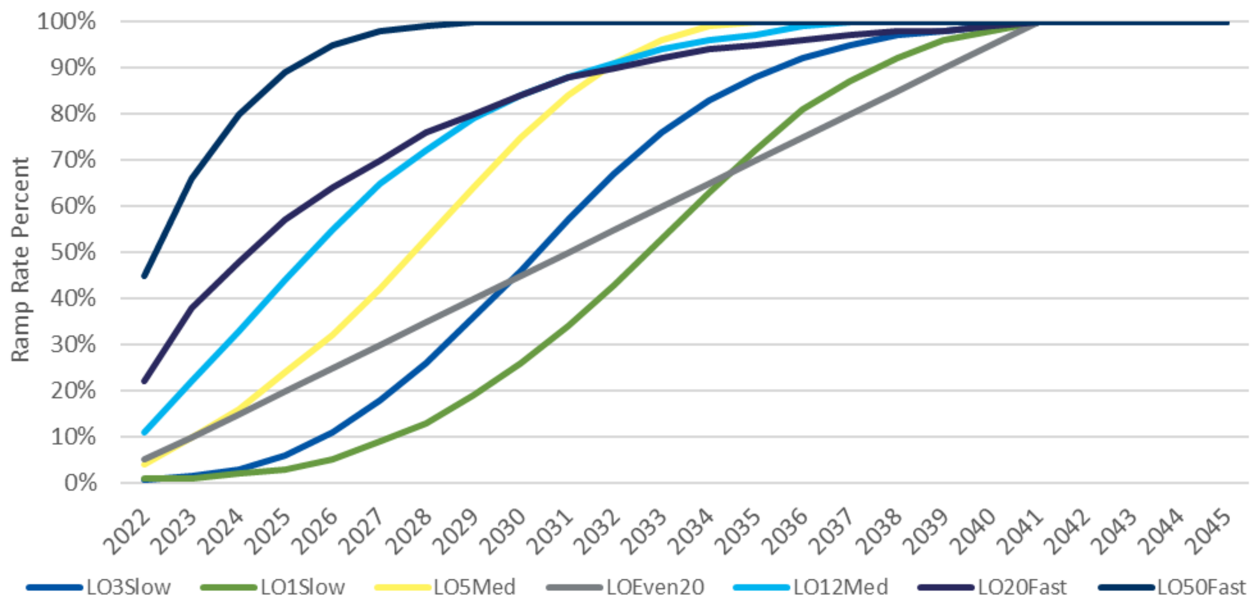
Figure 10. Equation for Estimating Achievable Technical Potential

As illustrated in Figure 10, achievable technical potential is the product of technical potential and both the maximum achievability factor and the ramp rate percentage. Cadmus used maximum achievability factors from the Council's draft 2021 Plan supply curves. Ramp rates are measure-specific and were based on the ramp rates developed for the Council's draft 2021 Plan supply curves but were adjusted to account for this study's 2022 to 2045 horizon.

For discretionary measures, Cadmus assumed all savings are acquired at an even rate over the first 10 years of the study. In other words, achievable potential for discretionary measures equals one-tenth of the total cumulative achievable potential in each of the first 10 years of the study (2022 through 2031). After 2031, there is no additional potential from discretionary measures.

For lost opportunity measures, we used the same ramp rates as those developed by the Council for its draft 2021 Plan supply curves. However, the draft 2021 Plan ramp rates cover only the 2022 to 2041 period of this study's horizon. Because nearly all lost opportunity ramp rates approach 100%, we set ramp values for 2041 through 2045 to equal the 2041 value from the Council's draft 2021 Plan. Figure 11 illustrates the lost opportunity ramp rates.

Figure 11. Lost Opportunity Ramp Rates



Develop IRP Inputs

Cadmus developed energy efficiency supply curves to allow PSE's IRP optimization model to identify the cost-effective level of energy efficiency. PSE's optimization model required hourly forecasts of electric energy efficiency potential and monthly forecasts of gas potential. To produce these hourly forecasts, we applied hourly end use load profiles shapes to annual estimates of achievable technical potential for each measure. These hourly end use load profiles are generally the same as those used by the Council in its draft 2021 Plan supply curves and by the RTF in its UES measure workbooks (including generalized shapes that we expanded to hourly shapes).

Cadmus worked with PSE to determine the format of inputs into the IRP model. We grouped energy efficiency and CHP potential into the levelized costs bundles shown in Table 15 and Table 16. Whereas the 2019 CPA included only 10 bundles – with the highest cost bundle representing energy efficiency potential at a net total resource cost (TRC) levelized cost greater than $150 per megawatt-hour – the 2021 CPA update includes three additional bundles which add greater granularity for more expensive resources. The number and delineating values of the natural gas levelized cost bundles remain unchanged from the 2019 CPA.

Table 15. Electric Levelized Cost Bundles

Bundle	Electric Bundle ($/kWh)
1	($9,999.000) to $0.028
2	$0.028 to $0.055
3	$0.055 to $0.062
4	$0.062 to $0.070
5	$0.070 to $0.077
6	$0.077 to $0.085
7	$0.085 to $0.115

Bundle	Electric Bundle ($/kWh)
8	$0.115 to $0.130
9	$0.130 to $0.150
10	$0.150 to $0.175
11	$0.175 to $0.200
12	$0.200 to $0.225
13	$0.225 to $999.00

Table 16. Natural Gas Levelized Cost Bundles

Bundle	Natural Gas Bundle ($/Therm)
1	($9,999.00) to $0.22
2	$0.22 to $0.30
3	$0.30 to $0.45
4	$0.45 to $0.50
5	$0.50 to $0.55
6	$0.55 to $0.62
7	$0.62 to $0.70
8	$0.70 to $0.85
9	$0.85 to $0.95
10	$0.95 to $1.20
11	$1.20 to $1.50
12	$1.50 to $999.00

Energy Efficiency Potential

Scope of Analysis

PSE requires accurate estimates of technically-achievable energy efficiency potential because they are essential for its IRP and program planning efforts. PSE then bundles these potentials in terms of levelized costs of conserved energy so the IRP model can determine the optimal amount of energy efficiency potential PSE should select.

To support these efforts, Cadmus performed an in-depth assessment of technical potential and achievable technical potential for electric and natural gas resources in the residential, commercial, and industrial sectors. The next section is in two parts—the first summarizes resource potential by fuel and sector and the second presents detailed results by fuel and sector.

Summary of Resource Potential – Electric

Table 17 shows 2045 forecasted baseline electric sales and potential by sector.[5] Cadmus' analysis indicates that 706 average megawatts (aMW) of technically feasible electric energy efficiency potential will be available by 2045, the end of the 24-year planning horizon, which translates to an achievable

5 These savings derive from forecasts of future consumption, absent any utility program activities. Note that consumption forecasts account for the savings PSE has acquired in the past, but the estimated potential is inclusive of—not in addition to—current or forecasted program savings.

technical potential of 600 aMW. Should all this potential prove cost-effective and realizable, it will result in an 19% reduction in 2045 forecasted retail sales.

Table 17. Electric 24-Year Cumulative Energy Efficiency Potential

Sector	2045 Baseline Sales (aMW)	Achievable Technical Potential	
		aMW	Percentage of Baseline Sales
Residential	1,846	339	18%
Commercial	1,339	250	19%
Industrial	122	10	8%
Total	**3,306**	**600**	**19%**

Figure 12 shows each sector's relative share of the overall electric energy efficiency achievable technical potential. The residential sector accounts for roughly 57% of the total electric energy efficiency achievable technical potential, followed by the commercial (42%) and industrial (2%) sectors.

Figure 12. Electric 24-Year Achievable Technical Potential by Sector

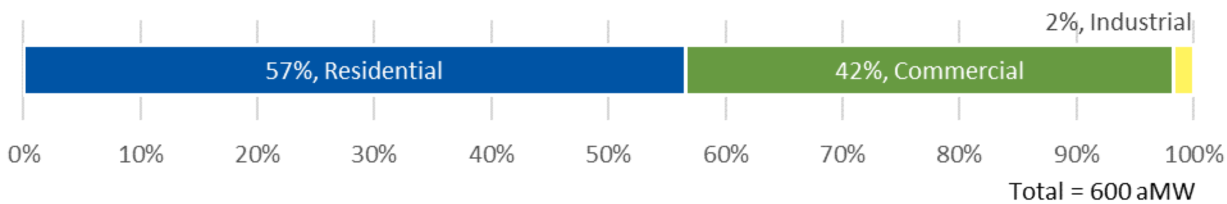


Figure 13 shows the relationship between each sector's cumulative (through 2045) electric energy efficiency achievable technical potential and the corresponding cost of conserved electricity.[6] For example, approximately 431 aMW of achievable technical potential exists, at a cost less than $150 per MWh.

6 In calculating levelized costs of conserved energy, non-energy benefits are treated as a negative cost. This means some measures will have a negative cost of conserved energy, although incremental upfront costs would occur.

Figure 13. Electric 24-Year Cumulative Energy Efficiency Supply Curve

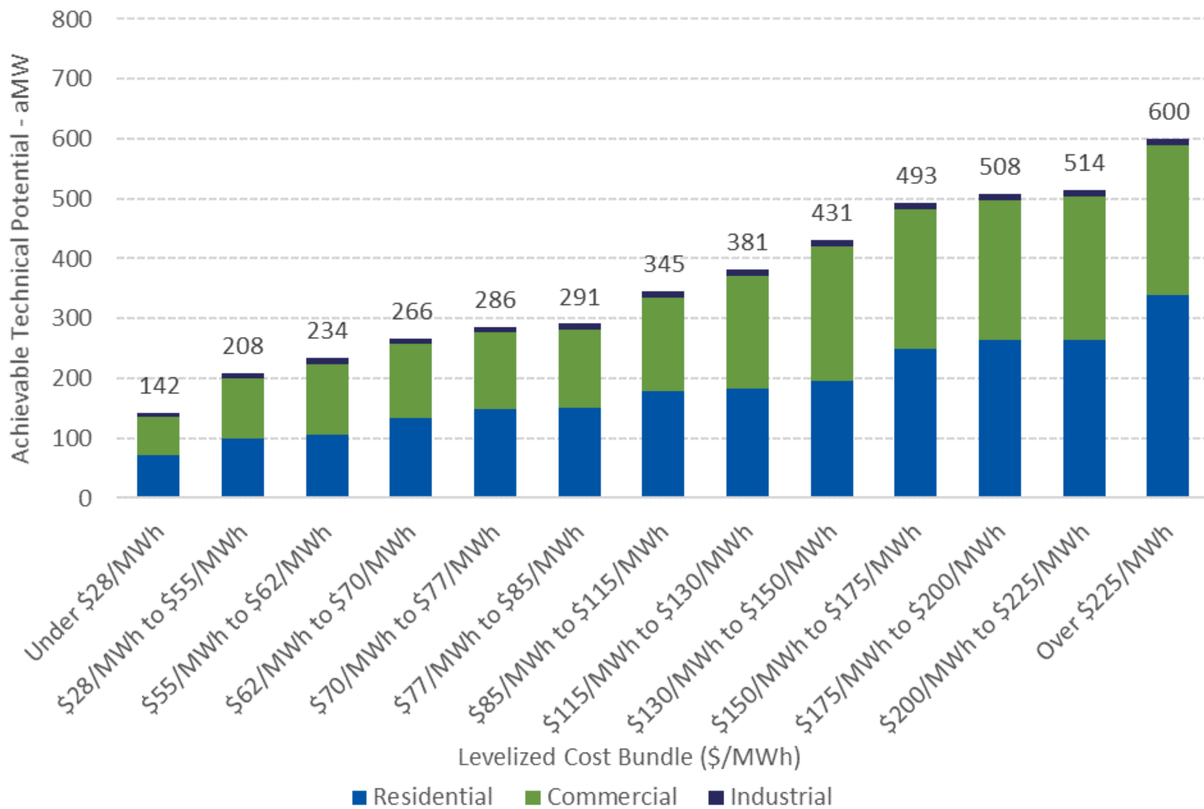
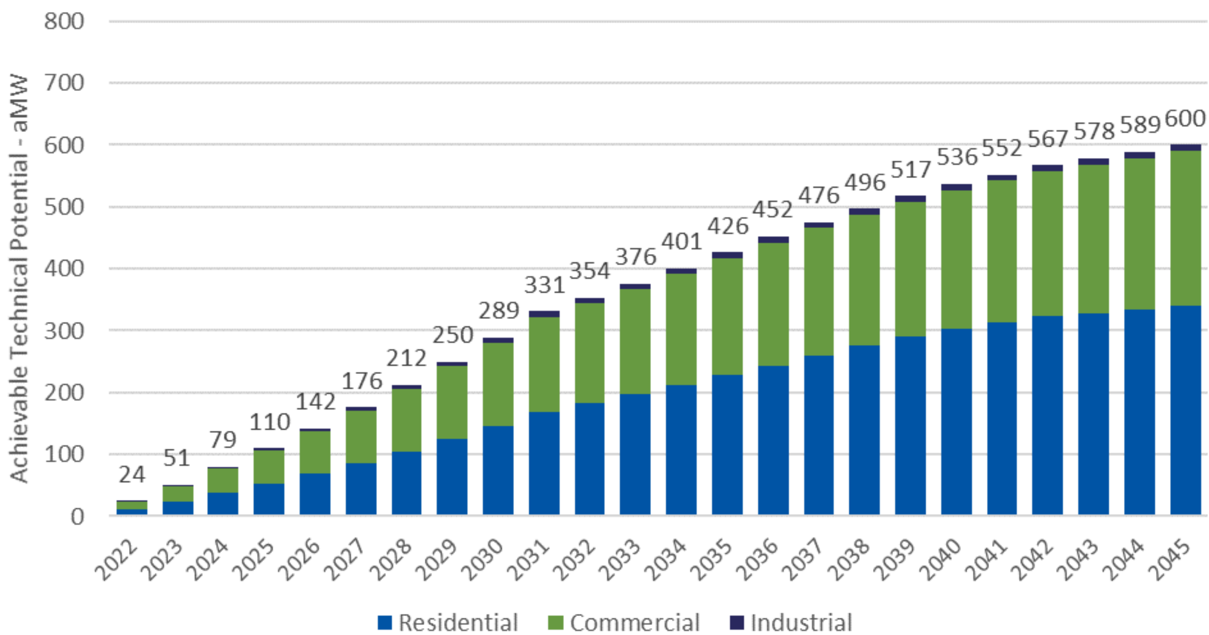


Figure 14 illustrates the cumulative potential annually available in each sector. The study assumes all discretionary resources will be acquired on a 10-year schedule between 2022 and 2031. The 10-year acceleration of discretionary resources will lead to the change in slope after 2031, at which point lost opportunity resources offer the only remaining potential.

Figure 14. Electric Energy Efficiency Potential Forecast



Summary of Resource Potential – Gas

Table 18 lists the 2041 forecasted baseline natural gas sales and potential by sector. The study results indicate roughly 174 million therms of achievable technical energy efficiency potential by 2041, the end of the 20-year planning horizon. Should all this potential prove cost-effective and realizable, it will amount approximately to a 15% reduction in 2041 forecasted retail sales.

Table 18. Natural Gas 20-Year Cumulative Energy Efficiency Potential

Sector	2041 Baseline Sales (MM Therms)	Achievable Technical Potential	
		MM Therms	Percentage of Baseline Sales
Residential	757	147	19%
Commercial	362	25	7%
Industrial	22	2	8%
Total	**1,141**	**174**	**15%**

Figure 15 shows the cumulative annual potential through 2041 available in each sector. The residential sector dominates natural gas potential with nearly 82% of total cumulative achievable technical potential, followed by commercial (17%) and industrial (1%).

Figure 15. Natural Gas 20-Year Achievable Technical Potential by Sector

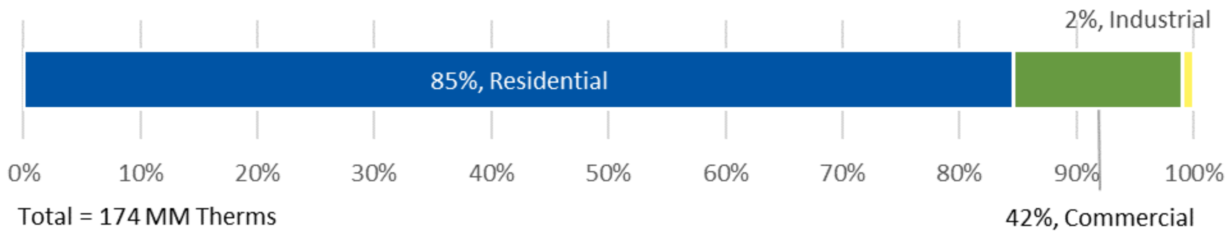


Figure 16 illustrates the relationship between identified natural gas achievable technical potential and its corresponding cost of conserved energy. For example, roughly 105 million therms of achievable technical potential will be available at a cost of less than $0.95 per therm.

Figure 16. Natural Gas 20-Year Cumulative Energy Efficiency Supply Curve

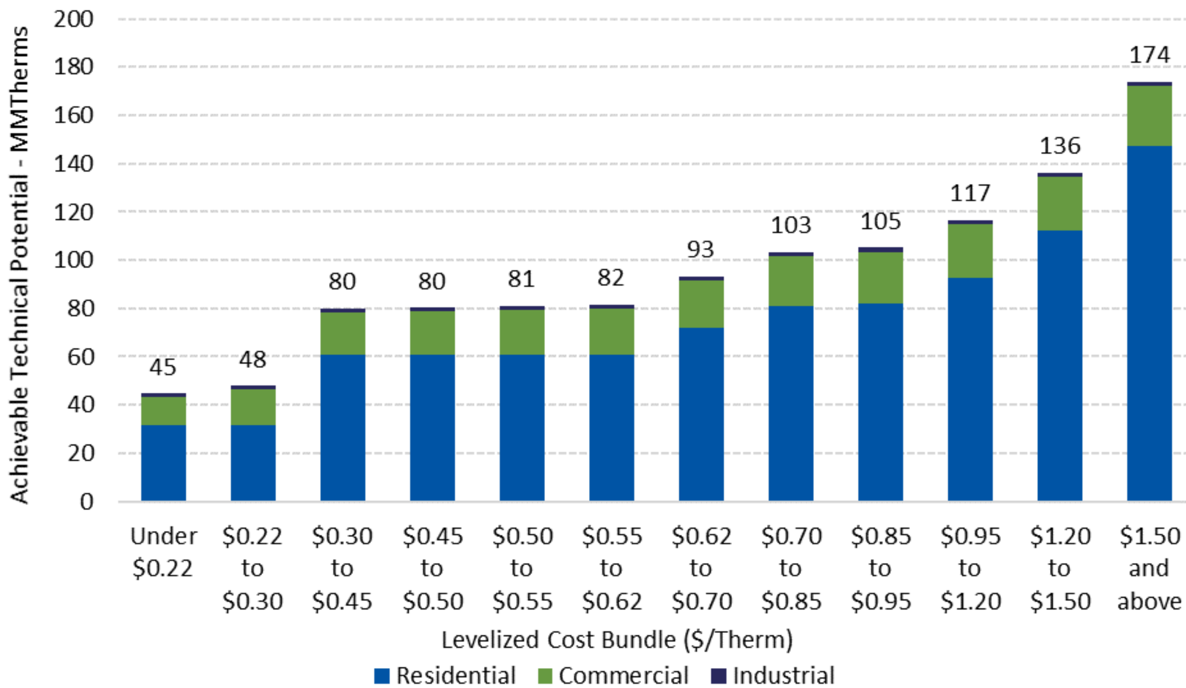
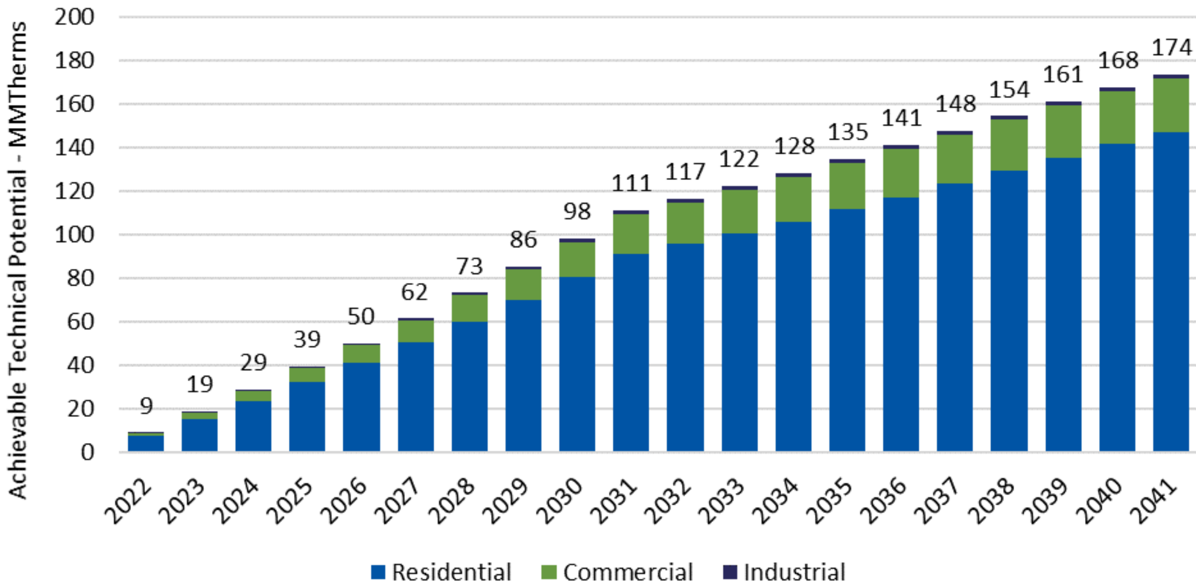


Figure 17 shows the cumulative potential available annually in each sector. As with electric potential, the study assumes all achievable discretionary opportunities will be acquired over the first 10 years of the study, from 2022 through 2031. Therefore, nearly 64% (111 MM therms) of the total natural gas achievable technical potential (174 MM therms) is achieved in the first ten years.

Figure 17. Natural Gas Energy Efficiency Potential Forecast



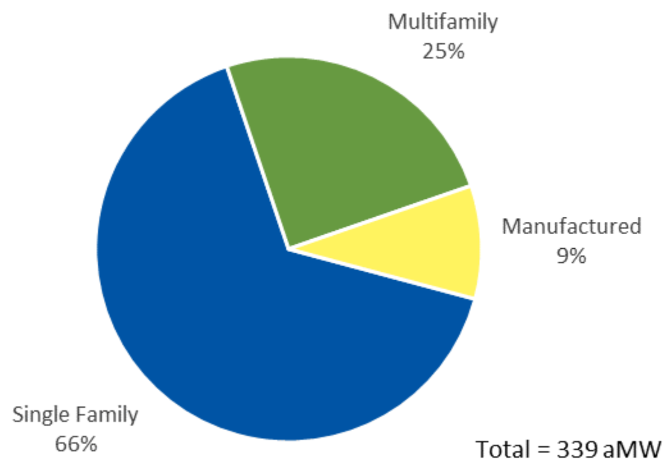
Detailed Resource Potential – Electric

Residential Sector – Electric

By 2045, residential customers in PSE's service territory will likely account for approximately 56% of forecasted electric retail sales. The single-family, manufactured, and multifamily dwellings comprising this sector present a variety of potential savings sources, including equipment efficiency upgrades (e.g., heat pumps, refrigerators), improvements to building shells (e.g., insulation, windows, air sealing), and increases in domestic hot water efficiency (e.g., heat pump water heaters).

As shown in Figure 18., single-family homes represent 66% of the total achievable technical residential electric potential, followed by multifamily (25%) and manufactured homes (9%). Each home type's proportion of baseline sales is the primary driver of these results, but other factors such as heating fuel sources and equipment saturations play an important role in determining potential.

Figure 18. Residential Electric Achievable Potential by Segment



For example, a higher percentage of manufactured homes use electric heat than do other home types, which increases their relative share of the potential. However, manufactured homes also tend to be smaller than detached single-family homes, and they experience lower per-customer energy; therefore, the same measure may save less in a manufactured home than in a single-family home.

Space heating end uses represent the largest portion (42%) of achievable technical potential. Appliances and water heating each also represent 15% and 14% respectively of the total identified potential (Figure 19). Lighting, an end use with considerably higher amounts of energy efficiency potential in previous PSE studies, comprises only 1% of the total residential electric energy efficiency potential due to the updated Washington State standard (H.B. 1444) and greater penetration of screw-based LEDs in recent years. The total achievable technical potential for residential increases to 339 aMW over the study horizon (Figure 20).

Figure 19. Residential Electric Achievable Potential by End Use

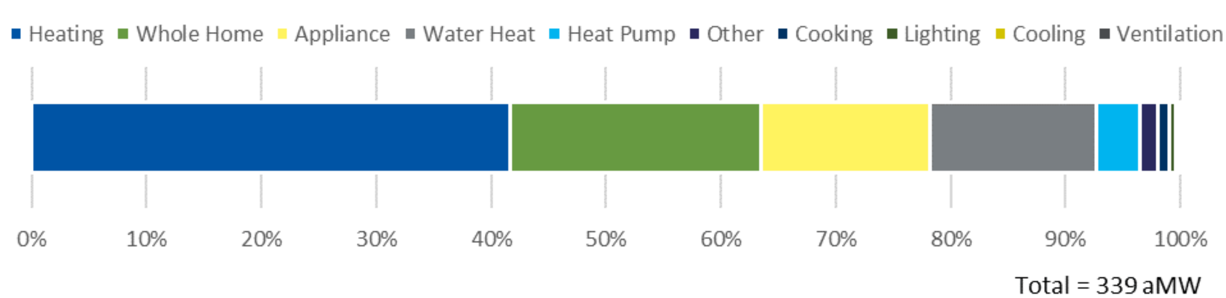


Figure 20. Residential Electric Achievable Potential Forecast

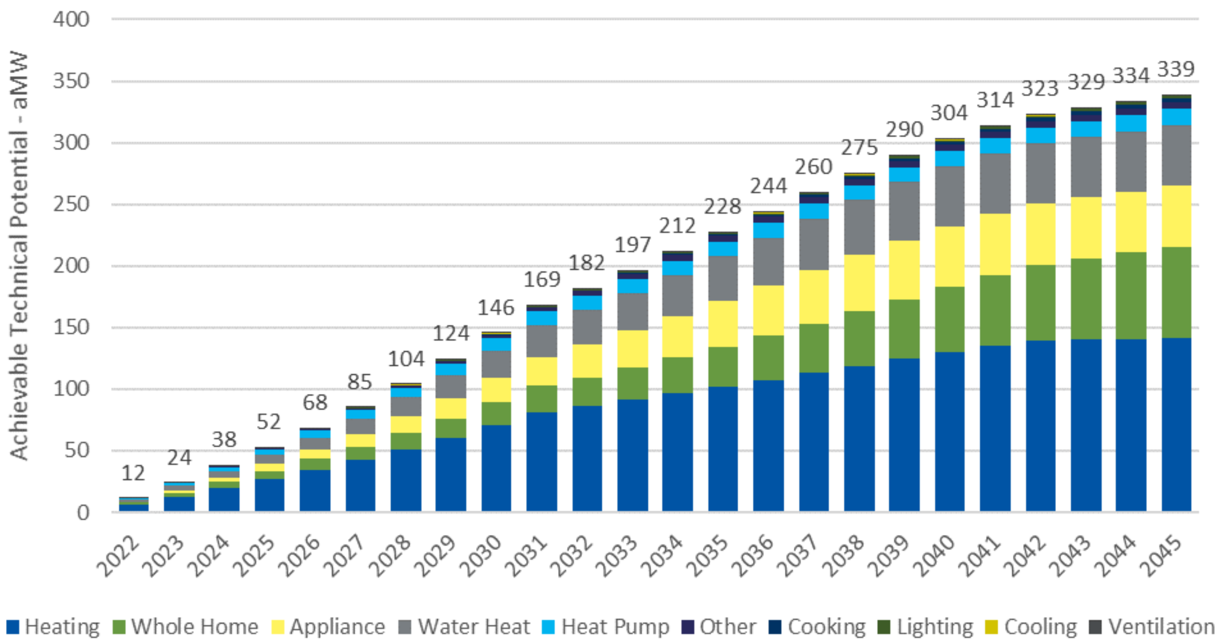


Table 19 lists the top 15 residential electric energy efficiency measures ranked in order of cumulative 24-year achievable technical potential. Combined, these 15 measures account for roughly 294 aMW, or approximately 87% of the total residential electric achievable technical potential. Various ductless heat pumps applications represent the measure group with the highest energy savings and eight of the top 15 measures reduce electric heating loads. These measures include equipment measures (i.e., ductless heat pumps and air-source heat pumps) and retrofit measures (i.e., windows, web-enabled thermostats, infiltration reduction, duct sealing, and wall insulation).

Table 19. Top Residential Electric Measures

Measure Name	Cumulative 10-Year Achievable Technical Potential (aMW)	Cumulative 24-Year Achievable Technical Potential (aMW)
Ductless Heat Pump	16.3	58.0
Whole Home	5.2	57.7
Heat Pump Water Heater	11.2	34.5
Window	26.3	26.3
Clothes Dryer	8.2	17.0
Home Energy Report	16.6	16.6
Heat Pump	4.9	17.7
Clothes Washer	5.9	14.2
Refrigerator	5.1	12.7
Thermostat	9.5	9.5
Solar Water Heater	3.9	3.9
Ground Source Heat Pump	0.7	8.1
Duct Sealing and Insulation	5.4	5.4
Wall Insulation	7.2	7.2
Duct Sealing	4.9	4.9

Residential Low Income – Electric

In addition to estimating potential for each residential housing segment, Cadmus also estimated potential for low income customers within PSE's electric service territory. Our team derived estimates of low income customers using income and housing sector variables from PSE's 2017 RCS. Based on PSE qualifying monthly income limit from PSE's Weatherization Assistance program. Varies by number of household occupants and 2016 annual household income (before taxes) from PSE's 2017 RCS. Table 20 provides the percent each residential sector's low income customers.

Table 20. PSE Low Income Customers - Electric Service

Segment	Electric Low Income Customers as a Percent of Total Electric Housing Segment Customers
Single Family	15.4%
Multifamily	24.4%
Manufactured	35.6%

Cadmus derived unit energy savings estimates specifically for low income customers using low income specific measures from PSE's business cases. Low income customer specific measures included the following:

- Weatherization. Attic, floor, and wall insulation, whole-home ventilation, and air/duct sealing
- Water heating. Tier 3 heat pump water heaters and low-flow showerheads and aerators
- HVAC equipment. Ductless heat pumps and air source heat pumps
- Smart thermostats, refrigerator replacements, and mobile home replacements

The study also apportioned savings from non-low income specific measures to low income customers for other measures, including:

- clothes dryers and clothes washers
- advanced power strips
- home energy reports
- refrigerator/freezer recycling
- freezers
- ovens and microwaves

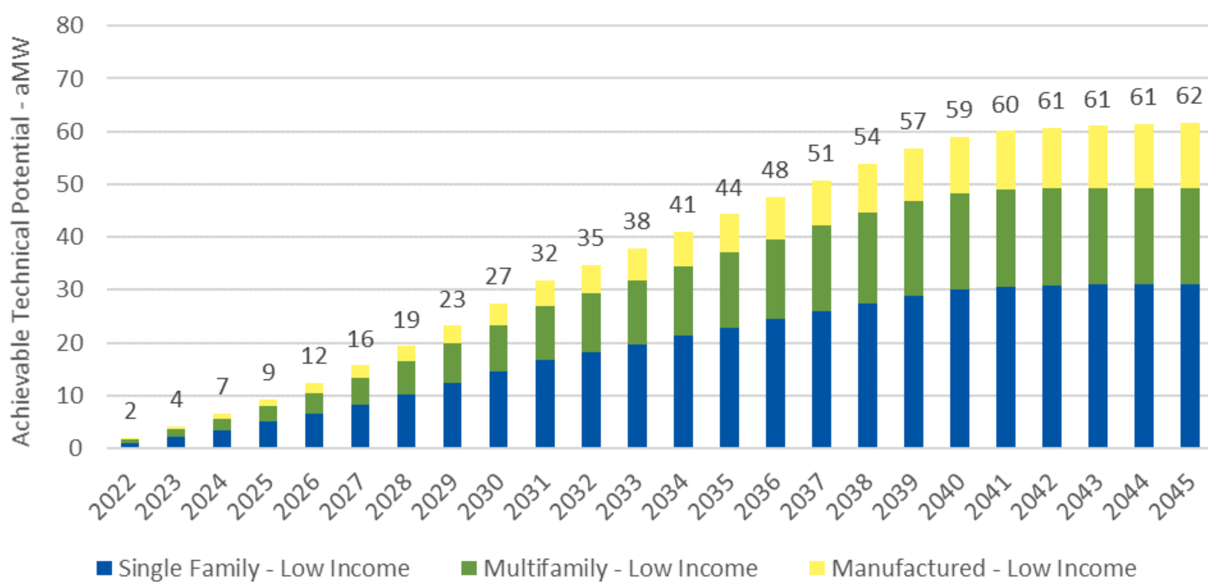
Table 21 shows the cumulative 10-year (through 2031) and 24-year (through 2045) achievable technical potential for PSE's low income customers by housing segment.

Table 21. Residential Low Income Customer Potential - Electric

Segment	Cumulative 10-Year Achievable Technical Potential (aMW)	Cumulative 24-Year Achievable Technical Potential (aMW)
Single Family - Low Income	16.8	31.0
Multifamily - Low Income	10.2	18.2
Manufactured - Low Income	4.8	12.3
Total	**31.8**	**61.6**

Figure 21 provides the cumulative residential low income electric achievable potential forecast by housing segment. The potentials shown in Figure 20 include the low income customer potential shown in Figure 21.

Figure 21. Residential Low Income Electric Achievable Potential Forecast

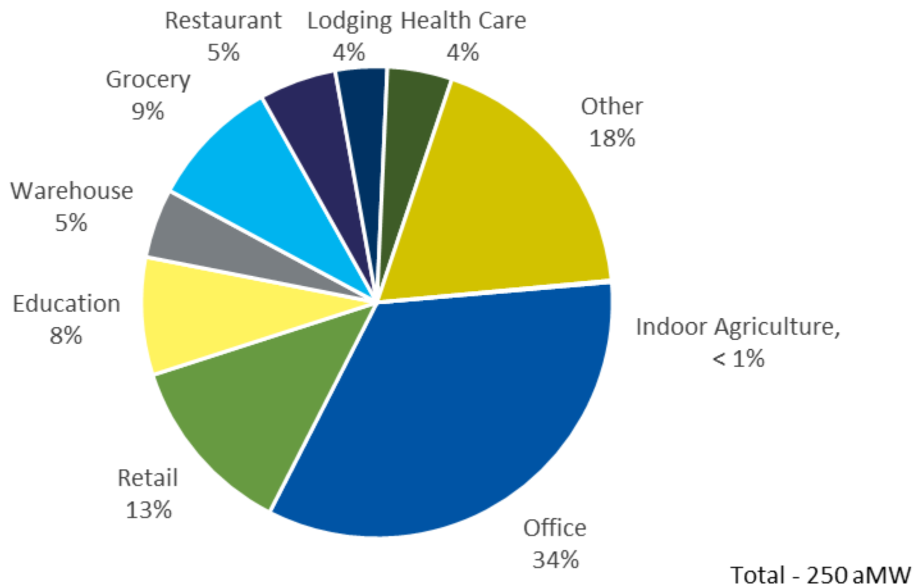


Commercial Sector - Electric

Based on the energy efficiency measure resources used in this assessment, electric energy efficiency achievable technical potential in the commercial sector will likely be 250 aMW over 24 years, which is approximately a 19% reduction in forecasted 2045 commercial sales.

As shown in Figure 22, the Office and Other segments represent 34% and 19%, respectively, of the total commercial achievable technical potential; no other single commercial segment represents more than 12% of commercial achievable technical potential. The Other segment includes customers that do not fit into any of the other categories and customers with insufficient information for classification.

Figure 22. Commercial Electric Achievable Potential by Segment



As shown in Figure 23, lighting efficiency improvements represent the largest portion for achievable technical end use savings potential in the commercial sector (39%), followed by other (29%), and cooling (8%) end uses. Lighting potential includes bringing existing buildings to code and exceeding code in new and existing structures. Figure 24 presents the cumulative electric commercial end use achievable technical by end use.

Figure 23. Commercial Electric Achievable Potential by End Use

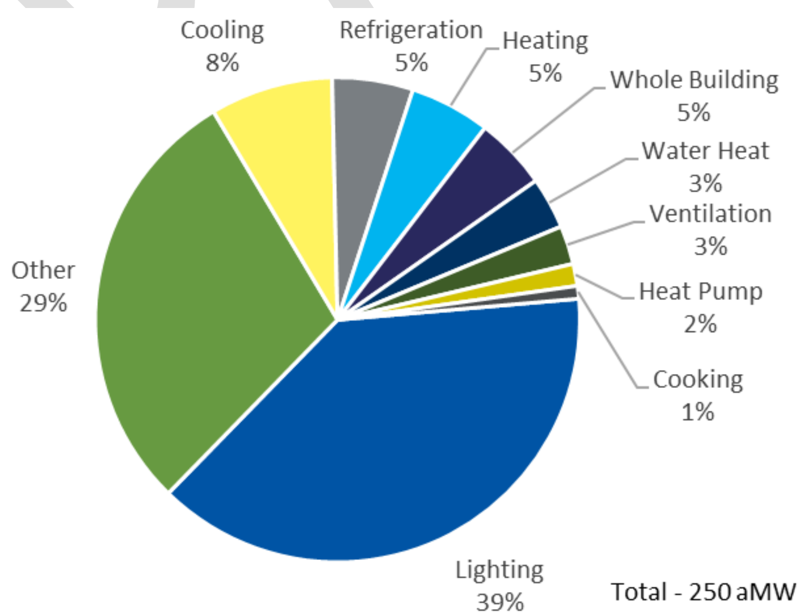


Figure 24. Commercial Electric Achievable Potential Forecast

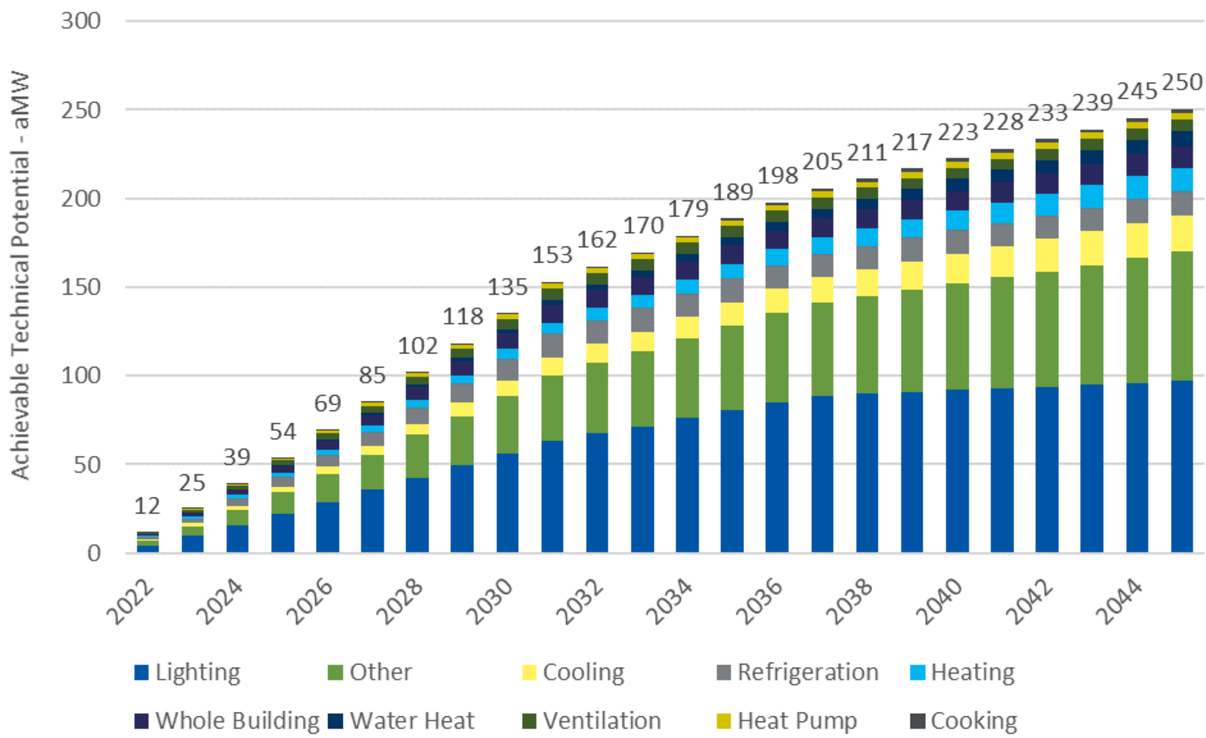


Table 22 lists the top 15 commercial electric energy efficiency measures ranked in order of cumulative 24-year achievable technical potential. Combined, these 15 measures account for 177 aMW, or approximately 71% of the total electric commercial achievable technical potential. Commercial LED lighting measures, including linear fixtures, high bay, and “other” applications including some measures falling outside of the top 15 commercial measures, account for approximately 97 aMW, or 39% of total commercial electric energy efficiency potential.

Table 22. Top Commercial Electric Measures

Measure Name	Cumulative 10-Year Achievable Technical Potential (aMW)	Cumulative 24-Year Achievable Technical Potential (aMW)
LED Panel	27.5	44.8
Variable Speed Efficient Motor	11.6	40.4
Linear LED	7.7	18.4
Variable Refrigerant Flow	4.4	10.6
Wastewater	9.6	9.6
High Bay LED Panel	5.2	8.1
Circulator Pump (bronze or stainless, learning-run hours)	7.1	7.1
Refrigeration – Electrically Commutated Motor	6.7	6.7
Pool Heat Recovery	5.7	5.7
Showerhead	5.2	5.2
Commercial Strategic Energy Management	4.2	4.9
Parking Garage Lighting	4.5	4.5
LED Sign	4.5	4.5
Residential-type Advanced Heat Pump Water Heater EF2.8	1.0	4.3
LED Other	4.2	4.2

Industrial Sector – Electric

This study estimates technical and achievable technical energy efficiency potential for major end uses in 19 major industrial sectors Across all industries, achievable technical potential is approximately 10 aMW over the 24-year planning horizon, corresponding to an 8% reduction of forecasted 2045 industrial electric retail sales.

Figure 25 shows 24-year electric industrial achievable technical potential by segment. Miscellaneous manufacturing represents 29% of the total electric industrial achievable technical potential, followed by streetlighting (26%), food manufacturing (17%), and wood manufacturing (8%). No other industry represents more than 5% of industrial electric potential.

Figure 25. Industrial Electric Achievable Technical Potential Forecast

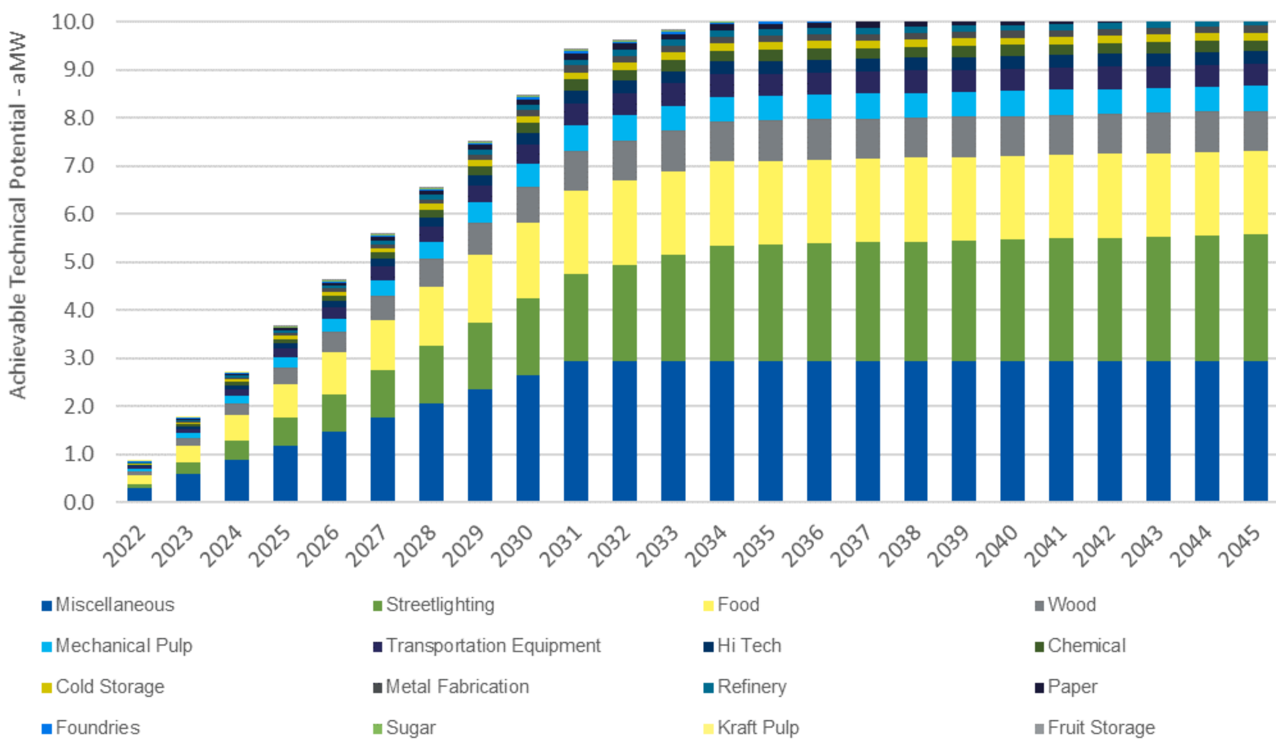


Table 23 presents electric cumulative 24-year achievable technical potential for the top 15 measures in the industrial sectors. Cadmus derived these measures from the Council's Seventh Power Plan and the top three measures combined—plant energy management, streetlighting, and energy project management—equal approximately 2.7 aMW of achievable technical potential, or roughly 27% of the industrial total.

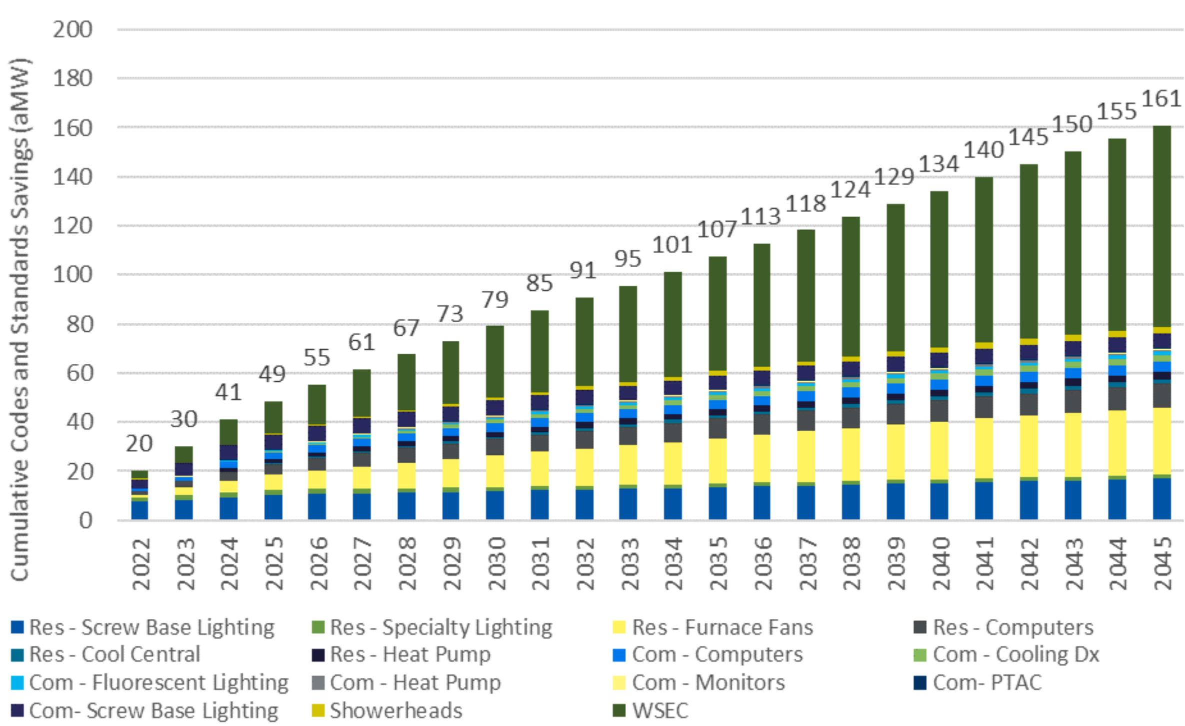
Table 23. Top Industrial Electric Measures

Reporting Group	Cumulative 10-Year Achievable Technical Potential (aMW)	Cumulative 24-Year Achievable Technical Potential (aMW)
Plant Energy Management	1.1	1.1
Streetlight - MH 400W - NR	0.7	0.9
Energy Project Management	0.7	0.7
Fan System Optimization	0.6	0.6
Integrated Plant Energy Management	0.6	0.6
Fan Equipment Upgrade	0.6	0.6
Pump System Optimization	0.5	0.5
Pump Equipment Upgrade	0.5	0.5
Streetlight - HPS 250W - NR	0.3	0.4
Streetlight - HPS 100W - NR	0.3	0.4
Wood: Replace Pneumatic Conveyor	0.3	0.3
Clean Room: Change Filter Strategy	0.3	0.3
Material Handling VFD2	0.3	0.3
Streetlight - MH 200W - NR	0.2	0.2
Food: Cooling and Storage	0.2	0.2

Codes and Standards – Electric

Figure 26 presents naturally occurring savings in PSE's service area from Washington state energy codes and equipment standards and federal equipment standards. Overall, the Washington State Energy Code (WSEC) accounts for roughly two-thirds of total electric codes and standards savings, with approximately 82 aMW over the 24-year study horizon. Of these 82 aMW, the commercial WSEC accounts for roughly 35 aMW, whereas the residential WSEC accounts for approximately 47 aMW.

Figure 26. Electric Codes and Standards Potential Forecast



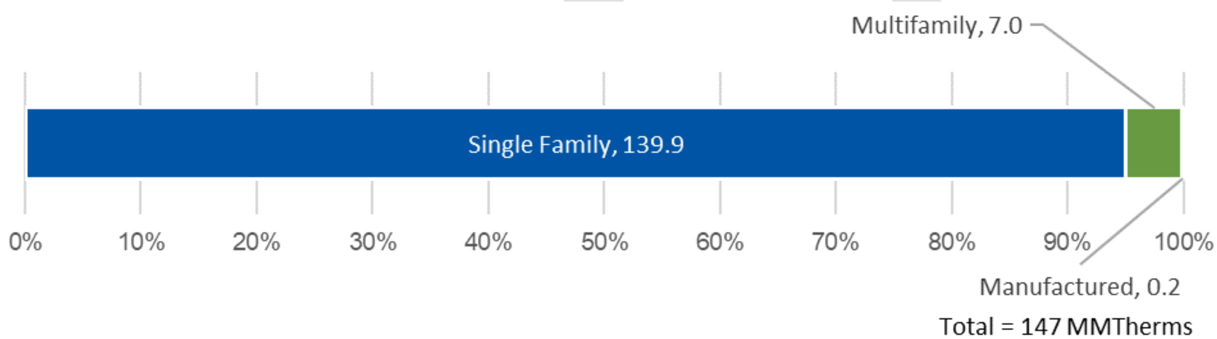
Detailed Resource Potential – Gas

Residential Sector - Gas

By 2041, residential customers will likely account for approximately 67% of PSE's natural gas sales. Unlike residential electricity consumption, there are relatively few natural gas-fired end uses (primarily space heating, water heating, and appliances including dryers and stove tops). Nevertheless, significant available energy savings opportunities remain. Based on the energy efficiency measures used in this assessment, achievable technical potential in the residential sector will likely provide about 147 million therms over 20 years, corresponding to a 19% reduction of forecasted 2041 retail sales.

Single-family homes account for 95% of the identified achievable technical potential, as Figure 27 shows. Less than 5% of total achievable technical potential occurs in multifamily and manufactured residences due to a lack of gas connections.

Figure 27. Residential Natural Gas Achievable Potential by Segment



As shown in Figure 28, space heating (59%), whole home measure (21%), and water heating (18%) end uses account for over 98% of the identified achievable technical potential, which combines high-efficiency equipment (such as condensing furnaces and water heaters) and retrofits (such as shell measures, smart thermostats, and duct and pipe insulation). Figure 29 shows the cumulative natural gas achievable technical potential by residential end use.

Figure 28. Residential Natural Gas Achievable Potential by End Use

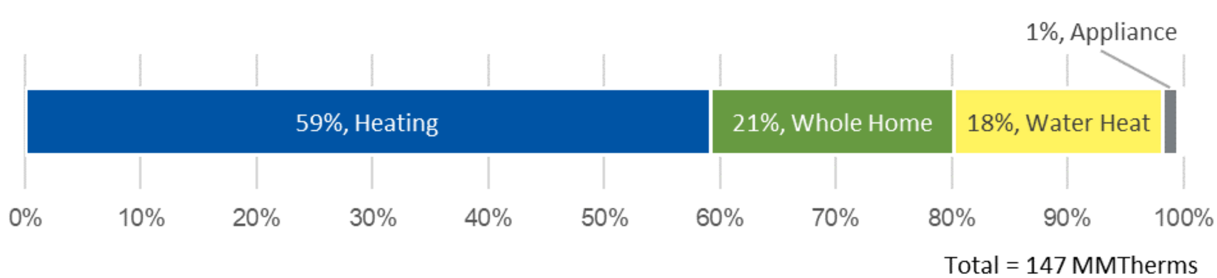


Figure 29. Residential Natural Gas Achievable Potential Forecast

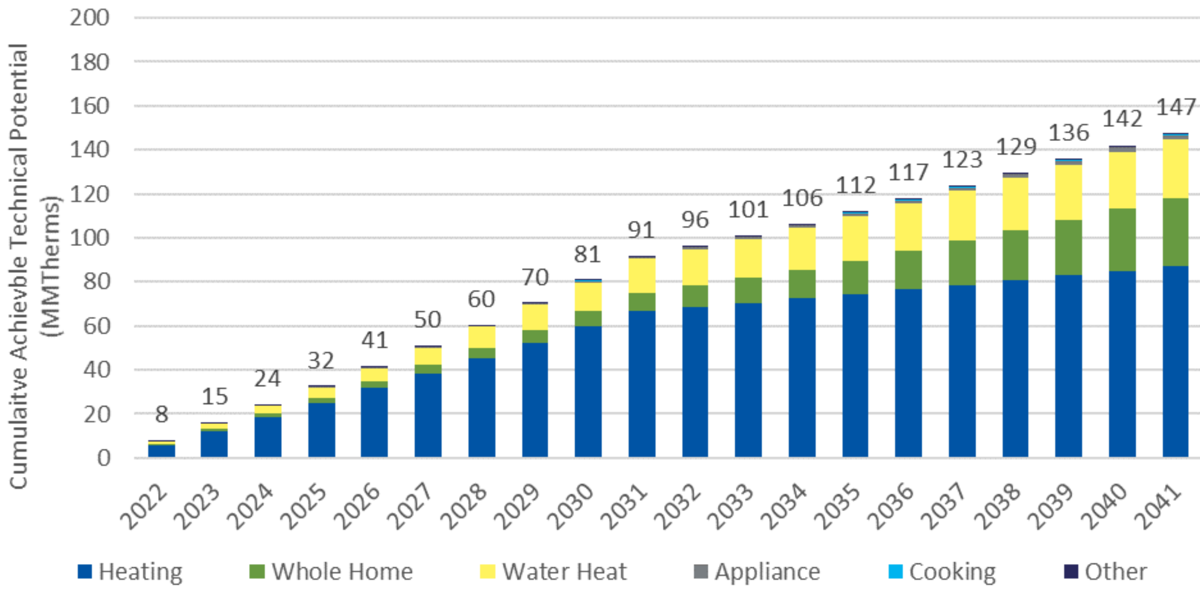


Table 24 shows the top 15 residential natural gas energy efficiency measures ranked in order of cumulative 20-year achievable technical potential. Combined, these 15 measures account for 136 million therms, or approximately 93% of the total residential achievable technical potential.

Table 24. Top Residential Gas Measures

Measure Name	Cumulative 10-Year Achievable Technical Potential (MM Therms)	Cumulative 20-Year Achievable Technical Potential (MM Therms)
Furnace	12.8	32.1
Whole Home	3.3	25.7
Water Heater	5.1	16.3
Thermostat	11.2	11.2
Window	10.5	10.5
Wall Insulation	7.3	7.3
Duct Sealing and Insulation	7.1	7.1
Duct Sealing	5.4	5.4
Home Energy Report	5.2	5.2
Thermostatic Restrictor Valve	3.1	3.1
Whole House Sealing	3.0	3.0
Floor Insulation	2.6	2.6
Showerhead	2.4	2.4
Aerators	2.3	2.3
Solar Water Heater	2.3	2.3

Residential Low Income – Gas

In addition to estimating potential for each residential housing segment, Cadmus also estimated potential for low income customers within PSE's natural gas service territory. Our team derived estimates of low income customers using income and housing sector variables from PSE's 2017 RCS. Based on PSE qualifying monthly income limit from PSE's Weatherization Assistance program. Varies by number of household occupants and 2016 annual household income (before taxes) from PSE's 2017 RCS. Table 25 provides the percent each residential sector's low income customers.

Table 25. PSE Low Income Customers - Gas Service

Segment	Electric Low Income Customers as a Percent of Total Electric Housing Segment Customers
Single Family	9.1%
Multifamily	8.3%
Manufactured	11.3%

Cadmus derived unit energy savings estimates specifically for low income customers using low income specific measures from PSE's business cases. Low income customer specific measures included the following:

- **Weatherization:** Attic, floor, and wall insulation, and air/duct sealing
- **Water heating**: ENERGY STAR tankless and storage water heaters, water heater pipe insulation, and low-flow showerheads and aerators
- **HVAC equipment:** Furnace replacements
- **Additional measures:** Smart thermostats and integrated space and water heating

The study also apportioned savings from non-low income specific measures to low income customers for other measures, including:

- clothes dryers and washers
- boilers
- home energy reports
- refrigerator/freezer recycling
- convection ovens

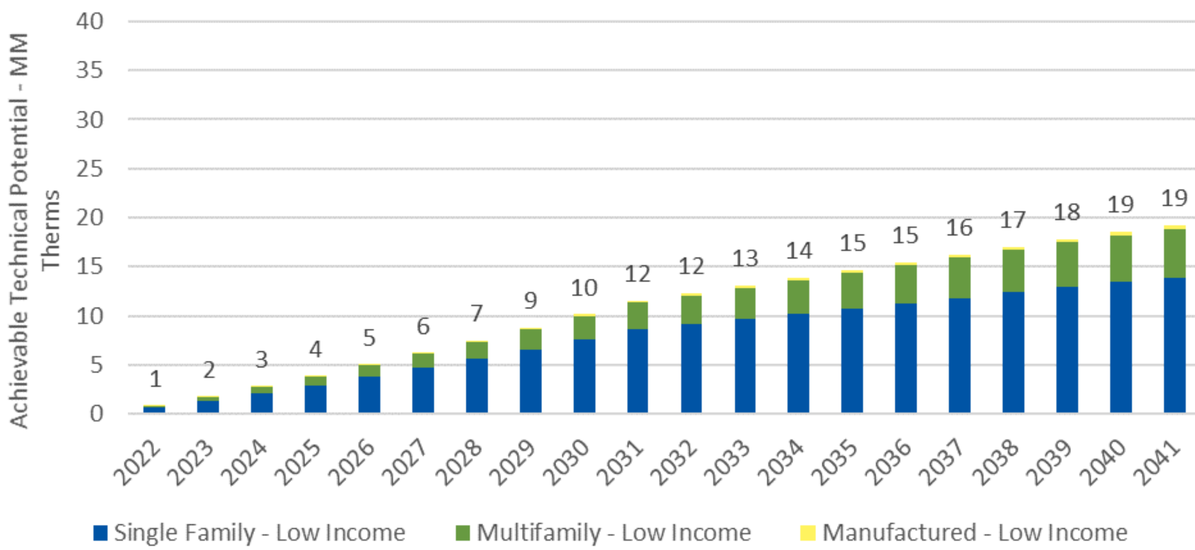
Table 26 shows the cumulative 10-year (through 2031) and 20-year (through 2041) natural gas achievable technical potential for PSE's low income customers by housing segment.

Table 26. Residential Low Income Customer Potential - Gas

Segment	Cumulative 10-Year Achievable Technical Potential (MM Therms)	Cumulative 20-Year Achievable Technical Potential (MM Therms)
Single Family - Low Income	8.6	13.8
Multifamily - Low Income	2.7	5.0
Manufactured - Low Income	0.2	0.4
Total	**11.6**	**19.2**

Figure 30 provides the cumulative residential low income natural gas potential forecast by housing segment. The potentials in Figure 29 include the low income customer potential shown in Figure 30.

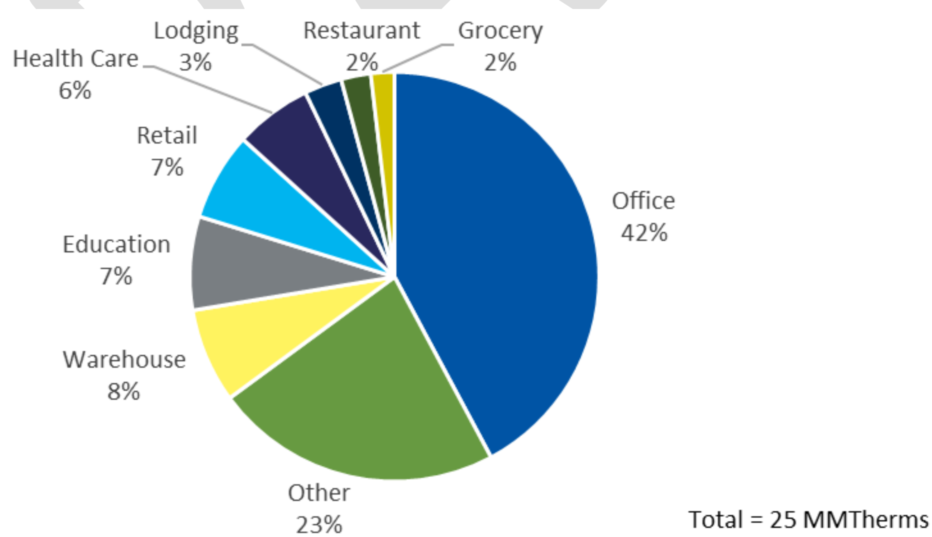
Figure 30. Residential Low Income Customer Potential - Gas



Commercial Sector – Gas

According to the resources used in this assessment, natural gas achievable technical potential in the commercial sector will likely be 25 million therms over 20 years, a 7% reduction in forecasted 2041 commercial retail sales. As shown in Figure 31., for natural gas customers, office buildings represent the largest portion of potential (42%), followed by other commercial facilities (23%), and warehouses (8%).

Figure 31. Commercial Gas Achievable Potential by Segment



As in the residential sector, far fewer gas-fired end uses exist compared to electric end uses. Space heating accounts for 44% of the identified commercial natural gas potential. The remaining potential is comprised mainly of whole building measures (27%),other end uses (15%), and water heating (11%), with the remaining potential coming from cooking (8%), and ventilation (3%), as shown in Figure 32.

Figure 33 provides the commercial natural gas annual cumulative achievable technical potential by end use.

Figure 32. Commercial Gas Achievable Potential by End Use

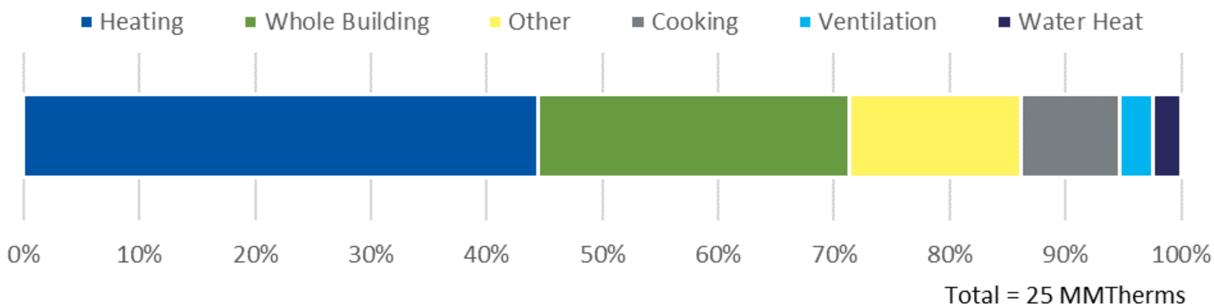


Figure 33. Commercial Gas Achievable Potential Forecast

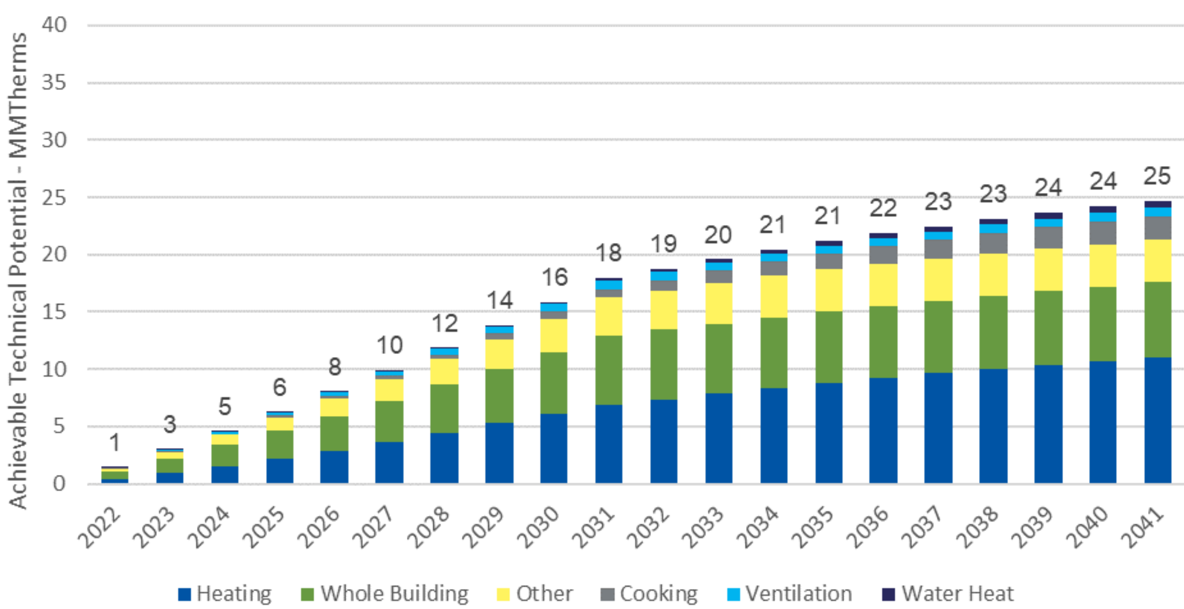


Table 27 shows the top 15 commercial natural gas energy efficiency measures ranked in order of cumulative 20-year achievable technical potential. Combined, these 15 measures account for approximately 18 million therms, or about 71% of the total natural gas commercial achievable technical potential.

Table 27. Top Commercial Gas Measures

Measure Name	Cumulative 10-Year Achievable Technical Potential (MM Therms)	Cumulative 20-Year Achievable Technical Potential (MM Therms)
Gas RTU Supply Fan VFD and Controller	3.0	3.0
Furnace LT 225 kBtuh High AFUE 92% Non-Weatherized	1.0	1.8
Furnace LT 225 kBtuh Premium AFUE 94% Non-Weatherized	0.8	1.9
Ozone Laundry	1.5	1.5
Pool Heat Recovery	2.4	2.4

Measure Name	Cumulative 10-Year Achievable Technical Potential (MM Therms)	Cumulative 20-Year Achievable Technical Potential (MM Therms)
DDC Energy Management	1.5	1.7
Commissioning Retro	1.5	1.5
Boiler 300 to 2500 kBtuh AFUE 95%	0.4	1.1
Clothes Washer	0.5	0.9
Boiler 300 to 2500 kBtuh AFUE 85%	0.3	0.8
DCV Kitchen	0.6	0.6
Oven Double Rack	0.2	0.6
Gas Water Heater 94% Efficient	0.2	0.5
Boiler 300 to 2500 kBtuh AFUE 79%	0.2	0.6
Convection Oven	0.2	0.5

Industrial Sector – Gas

Because electricity powers most industrial processes and end uses, the industrial sector represents a small portion of natural gas baseline sales and potential.

Across all industries, achievable technical potential totals approximately 1.7 million therms over 20 years. Although this represents 8% of forecasted 2041 industrial sales, it accounts for only 0.9% of the achievable technical potential across the three sectors. As shown in Figure 34, substantial achievable technical potential occurs in miscellaneous manufacturing (44%), transportation (17%), mechanical pulp (15%), and food production (10%).

Figure 34. Industrial Gas Achievable Technical Potential Forecast

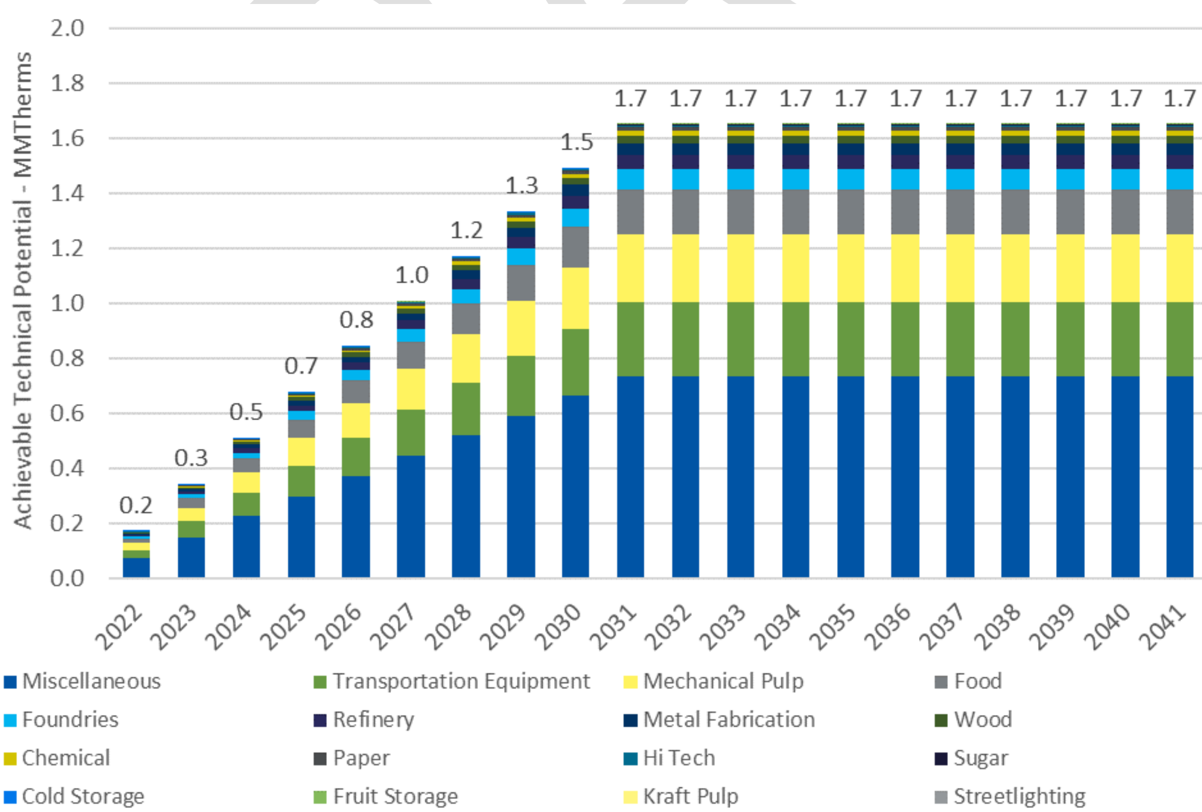


Table 28 lists the top 15 industrial natural gas energy efficiency measures ranked in order of cumulative 20-year achievable technical potential. Combined, these 15 measures account for approximately 1.4 million therms, or about 87% of the total natural gas industrial achievable technical potential.

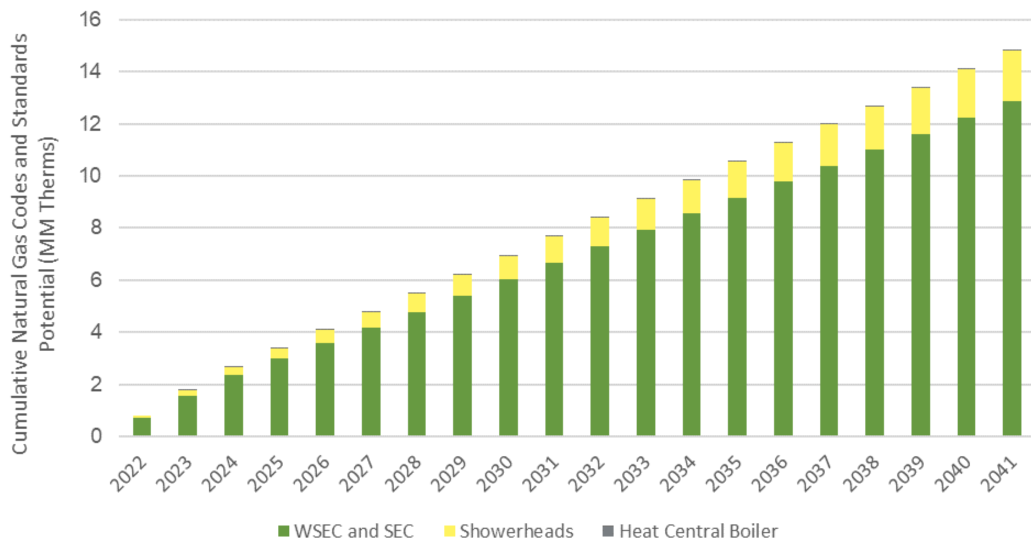
Table 28. Top Industrial Gas Measures

Measure Name	Cumulative 2031 Achievable Technical Potential (Therms)	Cumulative 2041 Achievable Technical Potential (Therms)
Equipment Upgrade - Replace Existing HVAC Unit with High Efficiency Model	196,537	196,537
Process Improvements to Reduce Energy Requirements	174,386	174,386
Improve Combustion Control Capability and Air Flow	138,408	138,408
HVAC Equipment Scheduling Improvements - HVAC Controls, Timers or Thermostats	114,484	114,484
Install or Repair Insulation on Condensate Lines and Optimize Condensate	110,464	110,464
Optimize Ventilation System	93,553	93,553
Waste Heat from Hot Flue Gases to Preheat	86,669	86,669
Heat Recovery and Waste Heat for Process	75,334	75,334
Equipment Upgrade - Boiler Replacement	71,916	71,916
Optimize Heating System to Improve Burner Efficiency, Reduce Energy Requirements and Heat Treatment Process	71,900	71,900
Building Envelope Infiltration Improvements	64,671	64,671
Building Envelope Insulation and Window/Door Improvements	62,980	62,980
Thermal Systems Reduce Infiltration; Isolate Hot or Cold Equipment	59,471	59,471
Replace Steam Traps	58,755	58,755
Repair and Eliminate Steam Leaks	53,159	53,159

Codes and Standards – Gas

Figure 35 presents naturally occurring natural gas savings in PSE's service area from Washington State energy codes and federal equipment standards. Overall, the WSEC represents most natural gas codes and standards savings, with approximately 13 million therms over the 20-year study horizon. The commercial and residential WSEC account for 6 million and 7 million therms, respectively.

Figure 35. Natural Gas Codes and Standards Forecast



Combined Heat and Power

CHP Technical Potential Approach

CHP technical potential represents total electric generation, if installing all resources in all technically feasible applications. Technical potential assumes every end-use customer in PSE's service territory—if meeting CHP energy demand requirements—installs a system. This largely unrealizable potential should be considered a theoretical construct.

Cadmus assessed applicable, technical CHP potential for the commercial and industrial sectors in PSE's service area. Traditionally, CHP systems have been installed in hospitals, schools, universities, military bases, and manufacturing facilities. They can be used, however, across nearly all commercial and industrial market segments with average monthly energy loads greater than approximately 30 kW, which encompasses nearly all commercial and industrial facilities.

CHP can be broadly divided into two subcategories, based on the fuels used:

- Nonrenewable CHP, typically using natural gas
- Renewable systems using biologically derived fuel (biomass or biogas)

Cadmus analyzed the following **non-renewable, natural gas-consuming CHP systems**:

- Reciprocating engines, which cover a wide range of sizes
- Microturbines, which represent newer technologies with higher capital costs
- Gas turbines, which typically are large systems

Cadmus analyzed the following **renewable-fueled systems:**

- ***Industrial biomass systems*** are used in industries for which site-generated waste products can be combusted in place of natural gas or other fuels (e.g., lumber, pulp, and paper manufacturing). This analysis assumed the type of combustion processes in a CHP system (generally steam turbines) to generate electricity on site. An industrial biomass system generally operates on a large scale, with a capacity greater than 1 MW.

- ***Anaerobic digesters*** create methane gas (i.e., biogas fuel) by breaking down liquid or solid biological waste. Anaerobic digesters can be coupled with a variety of generators, including reciprocating engines and microturbines, and typically are installed at landfills, wastewater treatment facilities, and livestock farms and feedlots.

Cadmus calculated technical potential to determine the number of eligible customers by segment and size (i.e., demand) in PSE's service area then applied assumptions about CHP or biomass/biogas system sizes and performance. Table 29 lists the sources Cadmus referenced for each input. Recent studies completed for the California Self-Generation Incentive Program (SGIP) have the largest sample sizes (as it is the longest-running CHP program in the nation). Cadmus also reviewed studies from other regions and, where possible, benchmarked SGIP data with other studies.

Table 29. Data Sources for CHP Technical Potential

Inputs	Source	Website Link (if available)
Capacity Factor, Performance Degradation, Heat Recovery Rate	Itron. *SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report].* Table 4-4: Summary of Operating Characteristics of SGIP Technologies. pp. 4-13. October 2015.	http://www.cpuc.ca.gov/General.aspx?id=7890
Measure Life	Marin, W., et al. *Understanding Early Retirement of Combined Heat and Power (CHP) Systems: Going Beyond First Year Impacts Evaluations*. 2015 International Energy Program Evaluation Conference, Long Beach.	https://www.iepec.org/wp-content/uploads/2015/papers/178.pdf
System Sizes	*Self-Generation Incentive Program Weekly Statewide Report.*	https://www.selfgenca.com/documents/reports/statewide_projects
Number of Customers, Projected Sector Growth, Line Losses	PSE data	N/A
Existing CHP Capacity	U.S. Department of Energy. "Combined Heat and Power Installation Database."	https://doe.icfwebservices.com/chpdb/
Customer Size Data	PSE data	N/A

CHP Achievable Potential Approach

Cadmus applied an achievable penetration rate to technical potential estimates to determine the market potential or likely future installations. Determining this rate involved reviewing a range of market penetration estimates using benchmarked estimates from recent studies, as listed in Table 30. We examined historic trends in installed capacity for several states (including Washington), technology, and fuel type using the U.S. Department of Energy (DOE) CHP Installation Database and reviewing states' favorability toward CHP as scored by the American Council for an Energy-Efficient Economy (ACEEE).

Table 30. CHP Achievable Potential Data Sources

Input	Source	Website Link (if available)
Annual Market Penetration Rate	U.S. Department of Energy. "Combined Heat and Power Installation Database."	https://doe.icfwebservices.com/chpdb/
	Navigant. *2017 IRP Conservation Potential Assessment IRPAG Meeting Draft DSM Results.* Prepared for Puget Sound Energy. January 2017.	https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/GetDocument.ashx?docID=30&year=2016&docketNumber=160918
	U.S. Department of Energy. *Combined Heat and Power (CHP) Potential in the United States.* March 2016.	https://www.energy.gov/sites/prod/files/2016/04/f30/CHP%20Technical%20Potential%20Study%203-31-2016%20Final.pdf
	ICF International. *Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment*. Prepared for California Energy Commission. June 2012. CEC-200-2012-002-REV	http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002-REV.pdf
	ACEEE. "State-by-State CHP Favorability Index Estimate."	http://aceee.org/sites/default/files/publications/otherpdfs/chp-index.pdf

Using the ACEEE State-by-State CHP Favorability Index Estimate, we identified the top three most favorable states for CHP (California, Connecticut, and Massachusetts) and calculated the percentage of technical potential installed per year in these states over the five-year period 2012-2016. We also calculated this percentage for Washington state for comparison. This percentage is derived by dividing the capacity of CHP installed over the five-year period 2012-2016 (from the DOE CHP Installation Database) by the CHP potential (from the 2016 DOE CHP Potential in the United States) then dividing by five years. This provides an upper bound for the annual market penetration rate in PSE territory. Based on the benchmarking results (shown in Table 31) as well as the other data sources, we assumed an annual market penetration rate of 0.2% to provide the most likely and realistic achievable potential.

Table 31. Market Penetration for 2012-2016

State	MW Installed 2012-2016	Technical Potential (MW)	Percent of Technical Potential Installed Per Year
Washington	15.1	2,387	0.126%
California	382.2	11,542	0.662%
Connecticut	15.2	1,214	0.248%
Massachusetts	40.2	3,028	0.265%

Levelized Costs

For each technology, Cadmus calculated the levelized cost from a TRC perspective. Although assumptions varied between technologies, these sources were included in overall total resource levelized costs:

- Installation costs
- Federal tax credits and other rebates
- O&M costs assumed to occur annually, adjusted to the net present value
- Fuel costs

The levelized cost analysis used the sources shown in Table 32 as well as the sources listed above for technical and achievable potential. To calculate the TRC, Cadmus used PSE's inflation rate of 1.9% to adjust future costs to present dollars. The study divided costs by the system's production over its lifespan, obtaining the levelized cost of energy. Energy production includes PSE's average line loss factor of 6.80%, which represents avoided losses on the utility system, not energy losses from customer-sited units to the facility (assumed to be zero).

Table 32. CHP Levelized Cost Data Sources

Input	Source	Website Link (if available)
State Cost Adjustment	R.S. Means	N/A
Inflation and Discount Rate	PSE	N/A
Gas Rates and Gas Futures	Northwest Power and Conservation Council. *Fuel Price Forecast: Revised Fuel Price Forecasts for the Seventh Power Plan.* Table 1: Proposed Natural Gas at Henry Hub Price Range ($2012/MMBTU). pp. 11. July 2014.	https://www.nwcouncil.org/media/7113626/Council-FuelPriceForecast-2014.pdf
Installed Cost	U.S. Environmental Protection Agency. "Catalog of CHP Technologies." March 2015.	https://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf
O&M Cost	Itron. *SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report].* Appendix A. October 2015.	http://www.cpuc.ca.gov/General.aspx?id=7890
State and Federal Incentives and Tax Credits	U.S. Environmental Protection Agency. "dCHPP (CHP Policies and Incentives Database)."	https://www.epa.gov/chp/dchpp-chp-policies-and-incentives-database

Combined Heat and Power Results

Combined Heat and Power Technical Potential

Cadmus calculated technical CHP potential for new installations, based on sources described in the CHP Technical Potential Approach section of this report, including commercial and industrial customer data along with data on farms, landfills, and wastewater treatment facilities within PSE's power utility customer service area. This resulted in a total estimated 24-year, system-wide technical potential of 186 aMW (233 MW).

Table 33 details technical potential by area, sector, and fuel. These results exclude 83 MW of previous installed CHP capacity at eight facilities throughout PSE's territory.[7]

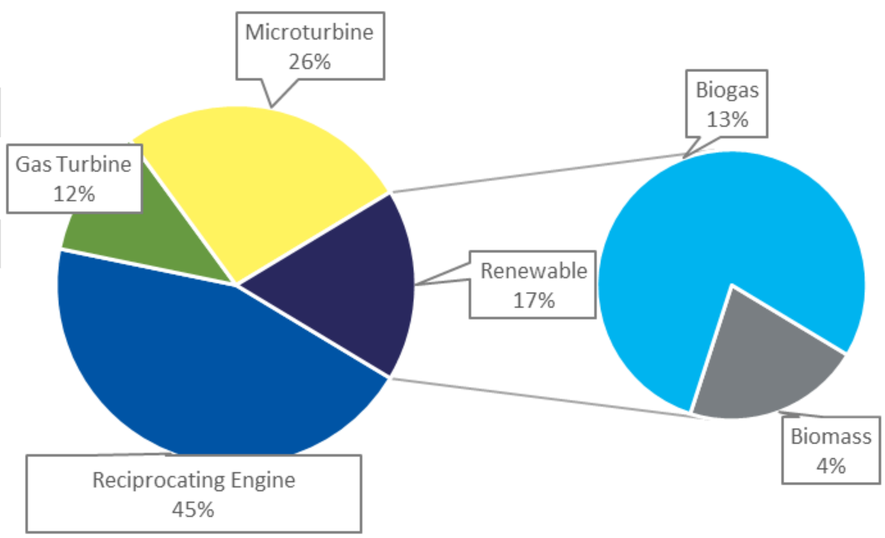
[7] U.S. Department of Energy. "Combined Heat and Power Installation Database." Accessed July 5, 2018.

Table 33. CHP Technical Potential by Area, Sector, and Fuel (Cumulative in 2045)

PSE	Technical Potential
Commercial	
Natural gas aMW	109
Number of sites	1,242
Industrial	
Natural gas aMW	56
Number of sites	293
Biomass and biogas aMW	35
Number of sites	67
Industrial total aMW	91
Industrial total number of sites	360
Total	
Total aMW	200
Total number of sites	1,602

The study based average energy production on unique capacity factors for each system type. To avoid double-counting opportunities across technologies, the study divided total potential for each size range into different technologies. Figure 36 shows the distribution of technical potential as a percentage of 2045 technical potential in aMW by these different technologies (e.g., reciprocating engines, microturbines, gas turbines, biomass, biogas).

Figure 36. Percentage of 2045 CHP Technical Potential in aMW by Technology



Combined Heat and Power Achievable Potential

Cadmus applied a market penetration rate of 0.20% per year to the technical potential data to determine achievable potential or likely installations in future years. The study based the assumed annual market penetration rate on secondary research of naturally occurring CHP installations in the region and on other CHP potential study reports, as described in the *CHP Achievable Potential Approach* section. As shown in Table 34 and Table 35, the market penetration rate was applied to technical potential for each year to calculate equipment installations along with achievable potential over the next 24 years. The study estimated a cumulative 2045 achievable potential of 7.82 aMW (9.78 MW of installed capacity) at the generator. We used PSE's line loss assumption of 6.8%.

Table 34. CHP 2045 Cumulative Achievable Potential Equipment Installations

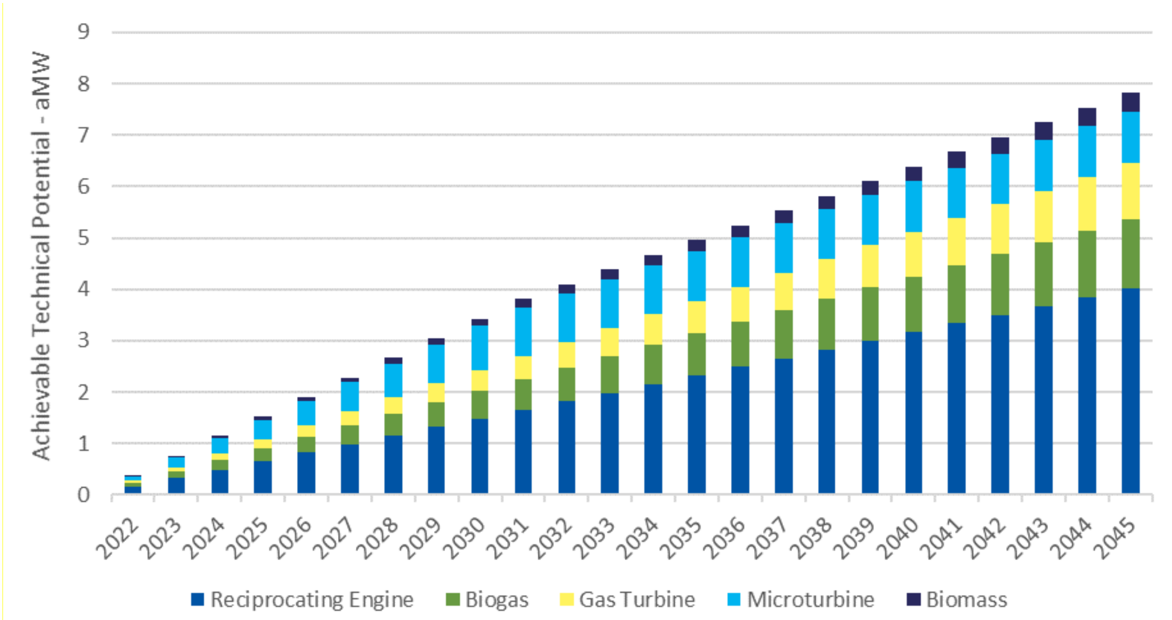
Technology	2045 Installs
Nonrenewable - Natural Gas (Total)	45
Reciprocating Engine	25
Gas Turbine	18
Microturbine	2
Renewables	2
Total CHP	47

Table 35. CHP 2045 Cumulative Achievable Potential at Generator

Technology	2045 aMW	2045 MW
Nonrenewable - Natural Gas (Total)		
30–99 kW	1.04	1.30
100–199 kW	0.83	1.04
200–499 kW	1.10	1.37
500–999 kW	0.76	0.96
1–4.9 MW	1.41	1.76
5 MW+	0.96	1.20
Renewable - Biomass (Total)		
< 500 kW	0.00	0.00
500-999 kW	0.00	0.00
1–4.9 MW	0.01	0.01
5 MW+	0.35	0.44
Renewable - Biogas (Total)		
Landfill	0.21	0.26
Farm	0.85	1.06
Paper Mfg	0.03	0.04
Wastewater	0.26	0.32
Total CHP	**7.82**	**9.78**

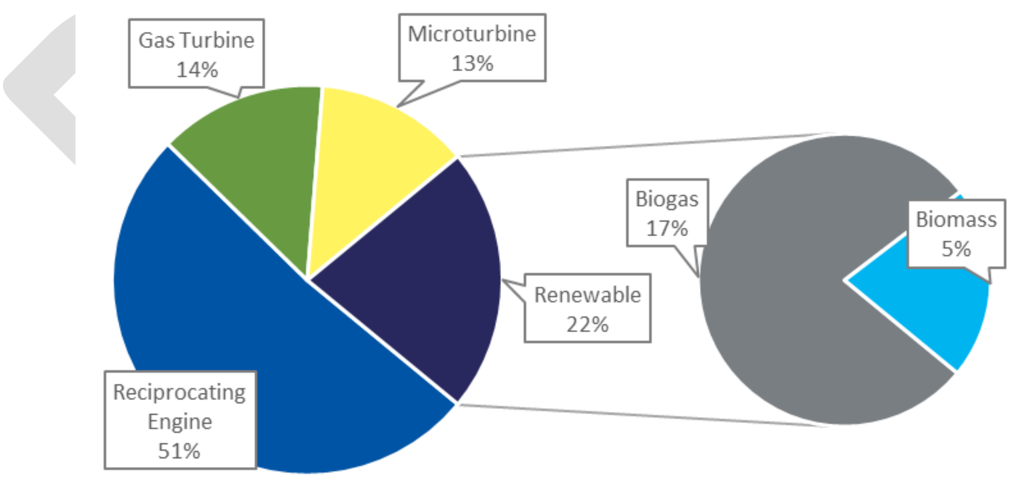
Figure 37 shows cumulative achievable CHP potential by year and technology. The decrease in the rate of adoption at year 2032 is caused by the assumed 10-year lifespan of microturbines. Microturbines are installed throughout the study horizon (2022-2045), but they don't begin to be decommissioned until 10 years after the start of the study. The rate for the first 10 years of the study is based on new installs, whereas the rate after the first 10 years includes new installs as well as decommissioned systems.

Figure 37. CHP Cumulative Achievable Potential by Year at Generation (aMW)



Of the 7.82 aMW of cumulative achievable potential, reciprocating engines made up 4.0 aMW (51%), gas turbines made up 1.3 aMW (14%), and microturbines made up 1.1 aMW (13%). The remaining 22% of renewable technologies consisted of biogas (1.0 aMW) and biomass (0.4 aMW) systems. In 2045, total energy generated across all technologies is 68.5 GWh (i.e., nonrenewable at 53.5 GWh and renewable at 15 GWh). Figure 38 shows the market potential of energy generation by each technology.

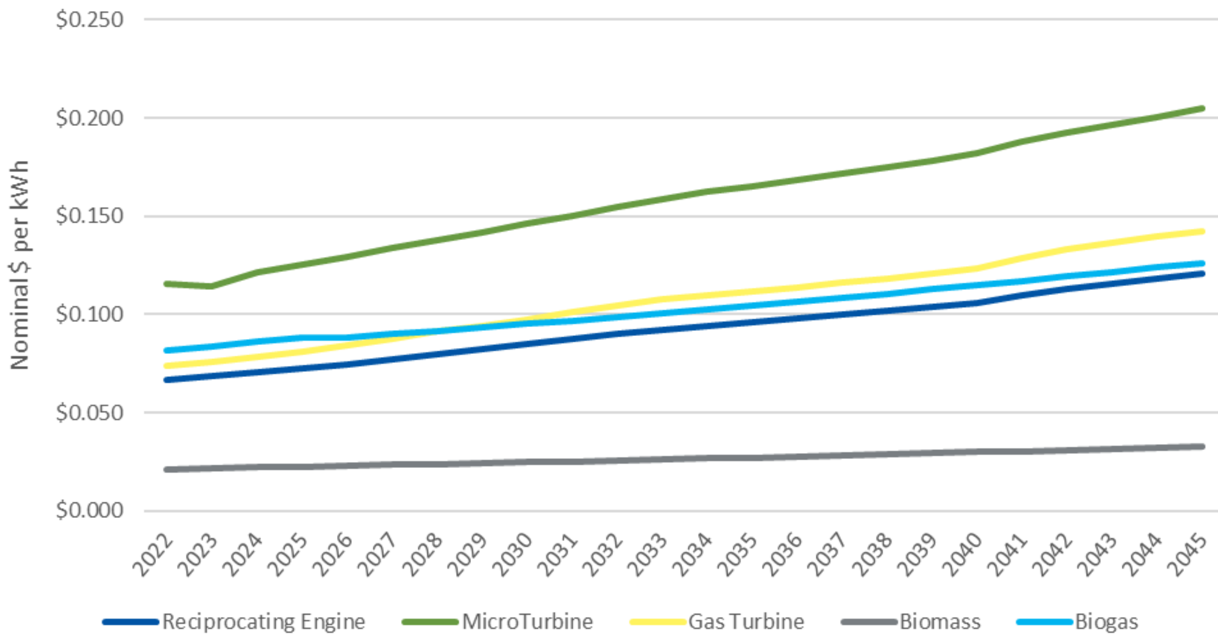
Figure 38. Breakout of CHP 2045 Cumulative Achievable Potential (GWh) at Generator



Combined Heat and Power Levelized Cost Results

Cadmus calculated the levelized cost, based on the TRC perspective, for each technology configuration in each installation year (2022 to 2045). Figure 41 shows the nominal levelized cost for units installed through the study period. The levelized cost increases slightly over time. For nonrenewable systems, the levelized cost increase results from increasing natural gas prices and inflation. For the renewable systems, the levelized cost increase results from inflation.

Figure 39. Nominal Levelized Cost by Technology and Installation Year



Section 2. Demand Response

Demand response programmatic options help reduce peak demand during system emergencies or periods of extreme market prices and promote improved system reliability. Demand response programs provide incentives for customers to curtail loads during utility-specified events (e.g., DLC programs) or offer pricing structures to induce participants to shift load away from peak periods (e.g., critical peak pricing (CPP) programs).

Overview of Technical and Achievable Potential

Cadmus' analysis focused on programs aimed at reducing PSE's winter peak demand. These programs include DLC space heat, DLC water heat, pricing, residential electric vehicle service equipment, residential behavioral, and nonresidential load curtailment and provide options for all major customer segments and end uses in PSE's service territory. Each of these programs may have more than one product option. For example, the nonresidential load curtailment program may offer customers a choice between manually turning off equipment to curtail loads or letting the utility communicate with an automated control system.

We defined each demand response program and its associated product option(s) according to typical program offerings, with particular specifications such as program implementation methods, applicable segments, affected end uses, load-reduction strategies, and incentives. To design the programs, we conducted an extensive review of secondary sources that addressed existing and planned programs predominantly in the Northwest, such as demand response potential assessments, program descriptions, evaluation reports, and pilot and demonstration projects from other utilities.

Estimate Technical Potential

Technical potential assumes 100% participation of eligible customers in all programs included in the assessment. Hence, technical potential represents a theoretical limit for unconstrained potential. Depending on the type of demand response product, this study applies either a bottom-up or a top-down method to estimate technical potential.

This study uses the bottom-up method for assessing potential for demand response programs that affect a piece of equipment in a specific end use, such as residential and commercial DLC space heat, residential DLC water heat, and residential electric vehicle service equipment. In the bottom-up method, technical potential is determined as the product of three variables: number of eligible customers, equipment saturation rate, and the expected per-unit (kW) peak load impact.

The top-down method estimates technical potential as a fraction of the participating facility's total peak-coincident demand. The calculation begins with disaggregating system electricity sales by sector, market segment, and end use then estimates technical potential as a fraction of the end-use loads. Total potential is then estimated by aggregating the estimated load reductions of the applicable end uses. The top-down estimation method is applied to demand response products that target the entire facility or load (rather than specific equipment), such as residential CPP, residential behavioral, commercial CPP, and commercial and industrial demand curtailment.

Estimate Achievable Potential

Achievable potential reflects a subset of technically feasible demand response opportunities that are assumed to be reasonably obtainable, based on market conditions and the end-use customers' ability and willingness to participate in the demand response market. There are two components for estimating achievable potential: market acceptance (or the participation rate) and the ramp rate. The participation rate is also broken down into program participation (the likelihood of the eligible population to enroll in a demand response program) and event participation (the probability that customers participating in a program will respond to a demand response event), an important consideration in voluntary demand response programs.

Ramp rates reflect the time needed for product design, planning, and deployment. Ramp rates vary depending on the type of demand response product and the stage in the product's life cycle. Ramp rates indicate when the maximum achievable potential may be reached, but they do not affect the amount of maximum achievable potential.

Both top-down and bottom-up methods calculate achievable potential as the product of peak load impact, program participation, and event participation, but note that event participation is assumed as 100% in involuntary load reduction programs such as DLC. Both methods apply ramp rates in the same manner to account for program start-up and ramp-up.

Calculate Levelized Costs

In the context of demand response, levelized cost of electricity (LCOE) represents the constant per-kilowatt-year cost of deploying and operating a demand response product, calculated as follows:

LCOE = (Annualized Cost of Demand Response Product) / (Achievable Annual Kilowatt Load Reduction)

This assessment calculated levelized costs based on the total resource cost (TRC) perspective, which includes all known and quantifiable costs related to demand response products and programs. The calculation of each demand response product's levelized cost accounts for the relevant, direct costs of a demand response product, including setup costs, program operation and maintenance costs, equipment cost, marketing cost, incentives, and transmission and distribution (T&D) deferral costs:

- **Upfront setup cost.** This cost item includes PSE's program development and setup costs for delivery of the subject demand response products, prior to program implementation. Because upfront costs tend to be small relative to total program expenditures, they can be expected to have a small effect on levelized costs.
- **Program operations and maintenance (O&M) cost.** This cost item includes all expenses that PSE incurs annually to operate and maintain the program. Expenses may cover administration, event dispatching, customer engagement, infrastructure maintenance, managing opt-outs and new recruiting of loads, and evaluation.
- **Equipment cost (labor, material, and communication costs).** This cost item includes all expenses necessary to enable demand response technology for each participating end user. The cost item applies only to each year's new participants. For some programs that assume or

require end users to already have demand response technology in place, this cost item would be zero.

- **Marketing cost.** This cost item includes all expenses for recruiting end users' participation in the program and applies only to new participants each year. For some programs (typically those run by third-party aggregators), the program O&M cost already includes this cost item.
- **Incentive.** This cost item covers all incentives offered to end users each year. Incentives may take the form of fixed monthly or seasonal bill credits or may be variable, tied to actual kilowatt load reduction. This assessment included 100% of the assumed incentive payment to eligible participants in the TRC levelized-cost calculation
- **Transmission and distribution (T&D) costs.** A transmission and distribution deferral value of $15.15/kW-year was included as a negative cost item in the levelized cost calculations for each product.
- **Discount rate.** A 6.8% discount rate, consistent with PSE's resource planning assumptions, was used for all demand response products.
- **Product life cycle.** All demand response products were assessed with an assumed 24-year life cycle.

Develop Supply Curves

Demand response supply curves show the quantity-price relationships for the demand response products that are being considered at the end of the planning period. A supply curve shows the incremental and cumulative achievable potential for a set of demand response products, in the ascending order of their levelized costs.

Demand Response Potential

This section introduces the analysis scope for assessing demand response potential in PSE's electric service territory, followed by a summary of potential results of the demand response programs and detailed descriptions of each program, including the product options and associated input assumptions.

Scope of Analysis

Focusing on reducing a utility's capacity needs, demand response programs rely on flexible loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost. These programs seek to help reduce peak demand and promote improved system reliability. In some instances, the programs may defer investments in delivery and generation infrastructure.

Demand response objectives may be met through a broad range of strategies, both price-based (such as time-of-use [TOU] or interruptible tariff) and incentive-based (such as DLC) strategies. This assessment considered 16 total demand response product options to estimate total achievable technical demand response potential in PSE's service area during peak load in winter. These product options included multiple residential and commercial DLC products targeting cooling, heating, and water heating end uses as well as electric vehicle service equipment (EVSE), commercial and industrial products such as demand curtailment contracts and interruptible tariffs, and other non-dispatchable products such as residential behavior demand response.

Cadmus reviewed recent demand response literature, including evaluations of pilots and programs in the Northwest and across the country, to design each demand response program. All but three of the evaluated product groups have two product options to capture the most common demand response product strategies from benchmarked studies. For example, customers participating in the residential DLC space heat program can either have a programmable communicating thermostat (PCT) installed in their home free of charge or let the utility communicate with the home's existing programmable PCT and receive a one-time bonus incentive.

Summary of Resource Potential

Table 36 lists the estimated resource potentials for all winter demand response programs for the residential, commercial, and industrial sectors during winter. The greatest achievable potential occurs in the residential sector from the DLC programs. Note that this analysis does not account for program interactions and overlap; therefore, the total achievable potential estimates may not be fully attainable upon implementation of all programs. The system peak load is calculated as the average of PSE's hourly loads during the 20 highest-load hours in the winter of 2019.

Table 36. Demand Response Achievable Potential and Levelized Cost by Product Option, 2045

Program	Product Option	Winter Achievable Potential (MW)	Winter Percent of System Peak	Levelized Cost ($/kW-year)
Residential CPP	Res CPP-No Enablement	64	1.28%	-$3
	Res CPP-With Enablement	2	0.04%	-$8
Residential DLC Space Heat	Res DLC Heat-Switch	50	1.00%	$71
	Res DLC Heat-BYOT	3	0.06%	$61
Residential DLC Water Heat	Res DLC ERWH-Switch	11	0.21%	$126
	Res DLC ERWH-Grid-Enabled	58	1.15%	$81
	Res DLC HPWH-Switch	< 1	< 0.1%	$329
	Res DLC HPWH-Grid-Enabled	1	0.02%	$218
Commercial CPP	C&I CPP-No Enablement	1	0.03%	$86
	C&I CPP-With Enablement	1	0.02%	$81
Commercial DLC Space Heat	Small Com DLC Heat-Switch	7	0.13%	$64
	Medium Com DLC Heat-Switch	5	0.10%	$29
Commercial and Industrial Curtailment	C&I Curtailment-Manual	3	0.06%	$95
	C&I Curtailment-AutoDR	3	0.06%	$127
Residential EVSE	Res EV DLC	9	0.17%	$361
Residential Behavioral	Res Behavior DR	9	0.17%	$76

Although PSE's electric distribution system incurs peak demand in winter, Cadmus also estimated the demand response potential for the summer season, as Table 37 shows. The remainder of the results presented in the demand response section focus on the winter demand response potential.

Table 37. Demand Response Achievable Potential and Levelized Cost by Product Option, 2045

Program	Product Option	Summer Achievable Potential (MW)	Summer Percent of System Peak	Levelized Cost ($/kW-year)
Residential CPP	Res CPP-No Enablement	39	1.0%	$5

Program	Product Option	Summer Achievable Potential (MW)	Summer Percent of System Peak	Levelized Cost ($/kW-year)
	Res CPP-With Enablement	1	< 0.1%	< $1
Residential DLC Space Heat	Res DLC Heat-Switch	24	0.6%	$160
	Res DLC Heat-BYOT	31	0.8%	$61
Residential DLC Water Heat	Res DLC ERWH-Switch	11	0.3%	$158
	Res DLC ERWH-Grid-Enabled	58	1.4%	$81
	Res DLC HPWH-Switch	< 1	< 0.1%	$406
	Res DLC HPWH-Grid-Enabled	1	< 0.1%	$218
Commercial CPP	C&I CPP-No Enablement	9	0.2%	$117
	C&I CPP-With Enablement	18	0.5%	$17
Commercial DLC Space Heat	Small Com DLC Heat-Switch	4	0.1%	$95
	Medium Com DLC Heat-Switch	4	0.1%	$126
Commercial and Industrial Curtailment	C&I Curtailment-Manual	2	< 0.1%	$41
	C&I Curtailment-AutoDR	3	0.1%	$36
Residential EVSE	Res EV DLC	9	0.2%	$361
Residential Behavioral	Res Behavior DR	5	0.1%	$77

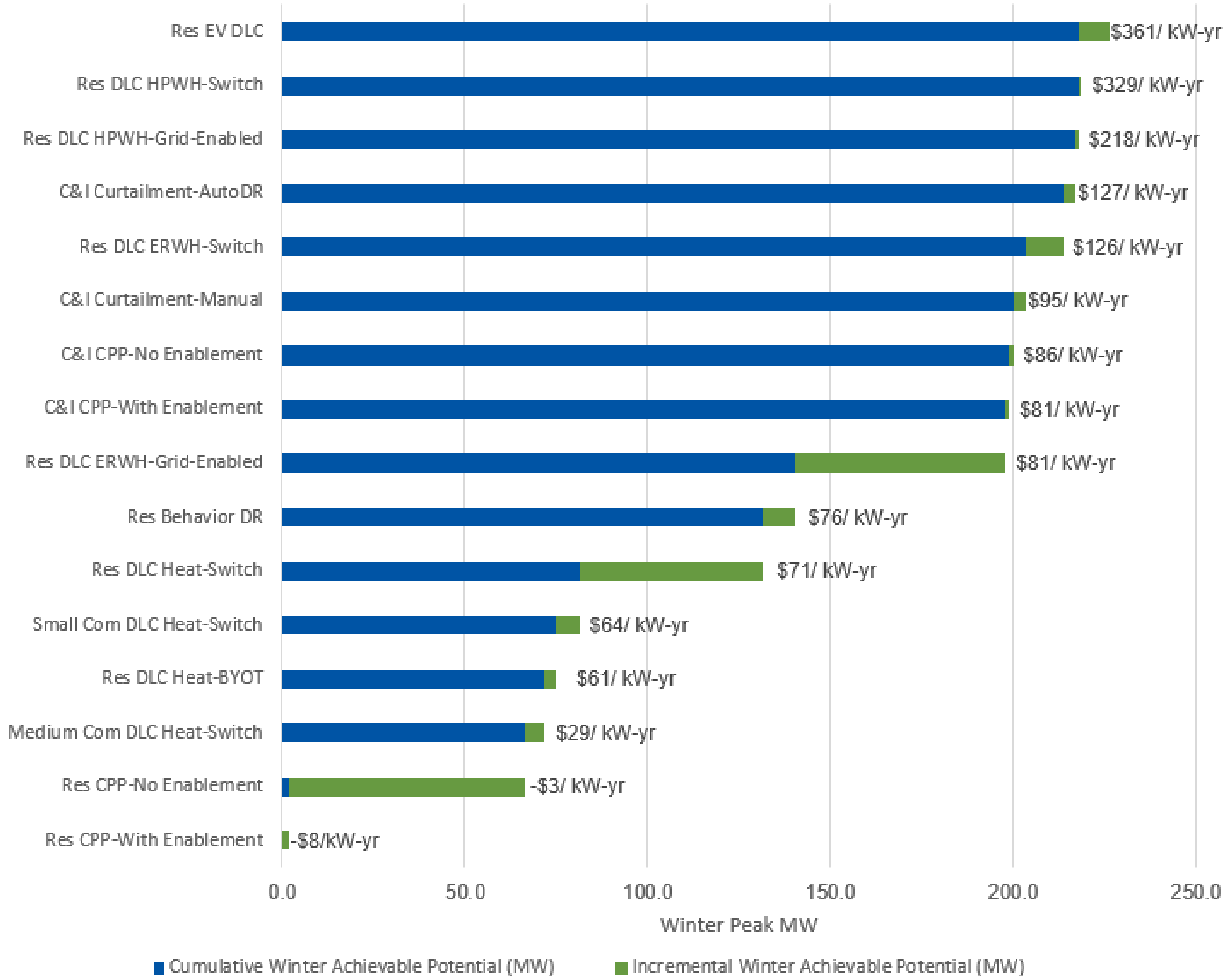
Cadmus constructed supply curves from quantities of estimated achievable technical demand response potential and per-unit levelized costs for each product option. Figure 40 shows the quantity of achievable potential (available during the system winter peak hours in 2045) as a function of levelized costs, at the product-option level. The green bars represent the incremental, achievable potential available for a product option at its associated levelized cost. The blue bars represent the cumulative achievable potential for the product options with lower levelized costs.

The supply curve starts with the lowest cost product option—residential CPP with enablement, which provides 2 MW of winter achievable potential at -$8 per kilowatt-year, levelized. The next lowest cost product in the supply curve is the same program but for the product option of no enablement, which adds 64 MW of winter achievable potential at -$3 per kilowatt-year, levelized. Thus, PSE could acquire a total of 66 MW of winter demand response at a negative levelized cost.

The two most cost-effective DR product options mentioned have negative costs due to the inclusion of deferred T&D costs in the TRC levelized cost calculation. Cadmus incorporated a transmission and distribution deferral value of $15.15/kW-year as a negative cost item in the levelized cost calculations for each product, resulting in negative values for products with very low costs. Without the inclusion of the T&D deferral value, the levelized costs of residential CPP with enablement and residential CPP with no enablement are $8 and $12, respectively.

Because residential EV DLC is the most expensive product option, PSE could acquire as much winter potential as achievable if it paid $361 per kilowatt-year (i.e., the levelized cost for the most expensive product option). However, PSE could acquire approximately 90% of the total achievable technical winter demand response potential at $95 per kilowatt-year, which is less than a third of the levelized cost of the most expensive product.

Figure 40. Demand Response Achievable Potential Supply Curve by Product Option

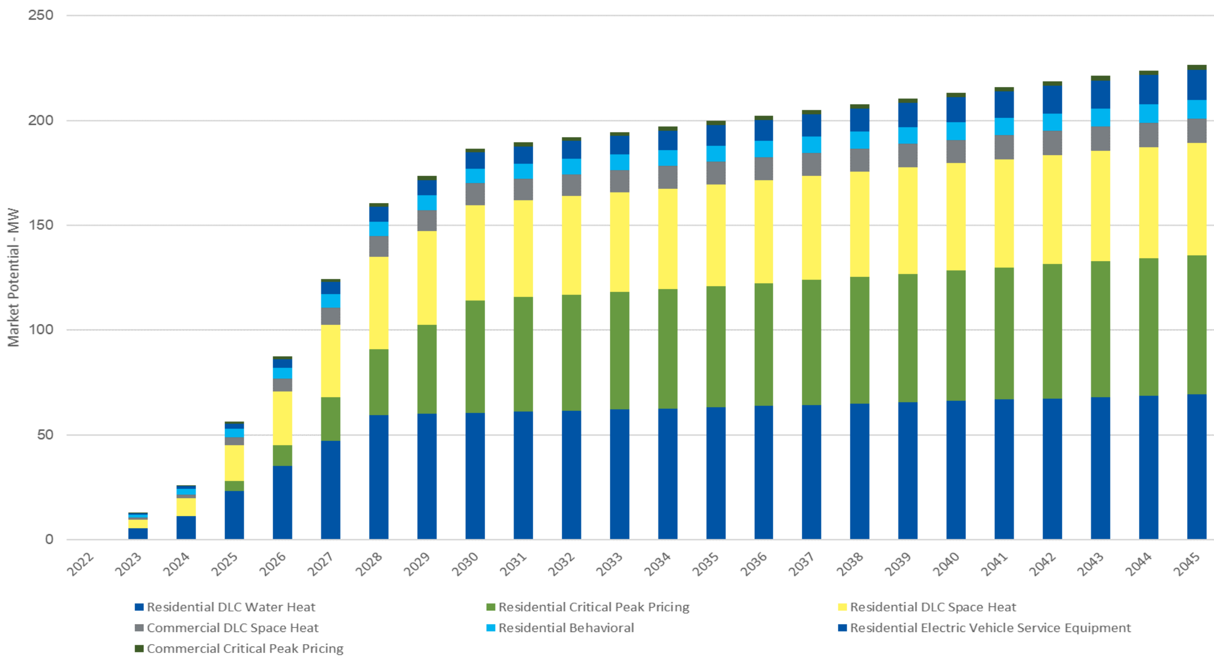


Cadmus assumes each program will require seven years of implementation before achieving the maximum achievable level of participation, allowing for an ample start-up period. Exceptions to this rule include:

- Residential Behavioral requires six years as this program would be an add-on to PSE's existing behavioral energy efficiency program, warranting a shorter ramp period than other DR programs.
- Residential Electric Vehicle Service Equipment requires five years to align with the 2021 Plan assumption to reach full program engagement.
- Residential DLC Heat – BYOT requires 5 years to align with ramp rate assumptions used in the 2021 Plan.
- CPP requires that PSE first establish a TOU tariff; therefore, the study assumed zero CPP participation until 2025.

Figure 41 shows the acquisition schedule for achievable potential by program.

Figure 41. Demand Response Achievable Potential Forecast by Program



Detailed Resource Potentials by Program and Product Option

This section provides the detailed demand response achievable potential and levelized cost for each program and its product options. For each program, Cadmus also describes the available product options and provides the costs and impact input assumptions.

Residential Critical Peak Pricing

Under a CPP program, customers receive a discount on their retail rates during noncritical peak periods in exchange for paying premium prices during critical peak events. The critical peak price is determined in advance, which gives customers some degree of certainty about participation costs.

The program follows the basic rate structure of a TOU tariff, where the rate has fixed prices for usage during different blocks of time (typically on-, off-, and mid-peak prices by season). During CPP events, the normal peak price under a TOU rate structure is replaced with a much higher price, which is generally set to reflect the utility's avoided cost of supply during peak periods.

CPP rates take effect for only a limited number of times during the winter. When emergency or high market prices are in effect, the utility can invoke a critical peak event. The utility notifies customers that rates have become much higher than normal and encourages them to shed or shift load. Typically, notification is via email or text a day prior to the CPP event and the day of the event. This analysis assumes that 5 critical peak price events are called, with a duration of four hours, for a total of 20 event hours during the winter.

Product Options

According to Cadmus' research of existing program studies across the nation, peak load impacts achieved by CPP programs vary depending on if the enabling technology, such as programmable communicating thermostats (PCTs), are integrated with the program. This analysis estimated two product options in the residential CPP program:

- No enablement (for customers without existing PCT)
- With enablement (for customers with existing PCT)

This analysis assumes that residential customers eligible for the with-enablement option have an existing PCT to control their central electric space heating equipment (i.e., electric furnace or air-source heat pump). During a critical peak event, these customers can reduce 40% of their space heat load, in addition to other end-use loads. All other residential customers are eligible for the no-enablement product option and achieve a relatively lower peak load impact.

Input Assumptions

Table 38 provides the cost and impact assumptions that Cadmus used in estimating potential and levelized costs for the residential CPP program.

Table 38. Residential Critical Peak Pricing Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	Assuming 1 FTE to set up the program.
O&M Cost	$ per year	$75,000	SDG&E (2017): $280,000; Applied (2017): $75,000. Assuming 0.5 FTE for the program.
Equipment Cost	$ per new participant	$0	No enablement: According to PSE (2018), AMI will be fully deployed in PSE's electric territory by 2023. Therefore, no equipment cost is incurred.
			With enablement: Because participant already has a PCT, no equipment cost is incurred.
Marketing Cost	$ per new participant	$25	Cadmus (2015): $25/new participant; Cadmus (2017): $25/new participant; Applied (2017): $50/new participant.
Incentives (annual)	N/A	$0	Program definition
Incentives (one time)	N/A	$0	Program definition
Attrition	% of existing participants per year	0%	N/A
Eligibility	% of segment load	Varies by product option and segment	No enablement: The proportion of residential customers who are not eligible for the with-enablement option.
			With enablement: The proportion of residential customers with a PCT (PSE's 2018 RCS) and have electric furnaces or air-source heat pumps (RBSA; heating zone 1).
Peak Load Impact	% of eligible segment load	Varies by product option and end use	No enablement: assuming 12% based on Cadmus (2015): 12%; Cadmus (2017): 12%; Applied (2017): 12.5%; and Brattle (2015): 14.8%.
			With enablement: For cool central, heat central, and heat pump end uses, assuming 40% based on Oklahoma (2011): 38.8%; DTE (2014): 44.5%; Nexant (2017) 44.6%. For other end uses, assuming 12%.

Parameters	Units	Values	Notes
Program Participation	% of eligible segment load	15%	Cadmus (2013b): 5%; Cadmus (2015): 10%; Cadmus (2017): 10%; Applied (2017): 17%; Brattle (2015): 29%.
Event Participation	N/A	No enablement: 100%	No enablement: peak load impact already takes into account of event participation.
		With enablement: 85%	With enablement: Customers can override the impact on their HVAC end uses by adjusting their PCTs.

Results

Residential CPP is the least expensive demand response program. As a tariff-based product, it does not offer incentives for load reductions. Without any enabling technology, residential CPP could obtain 64 MW of winter achievable potential by 2045 at -$3 per kilowatt-year, as shown in Table 39. Participating customers with enabling technology can provide even more peak load reductions, and—because PSE does not pay for the existing enabling technology—this peak load reduction is at a lower levelized cost of -$8 per kilowatt-year. Note that the potential results represent the load impact of a CPP event, during which only CPP prices are in effect.

Table 39. Residential Critical Peak Pricing Achievable Potential and Levelized Cost by Product Option

Product Option	Number of Events and Hours Curtailed	Notification Type	Levelized Cost ($/kW-year)	24-Year Achievable Potential (MW)
Res CPP-No Enablement	10 4-hour events	Day-ahead	-$3	64
Res CPP-With Enablement	10 4-hour events	Day-ahead	-$8	2

Residential Direct Load Control Space Heat

DLC programs seek to interrupt specific end-use loads at customer facilities through utility-directed control. When necessary, the utility, typically through a third-party contractor, is authorized to cycle or shut off participating appliances or equipment for a limited number of hours on a limited number of occasions. Customers do not have to pay for the control equipment or installation costs and typically receive incentives that are paid through monthly credits on their utility bills.

Product Options

For programs that target central electric space heating (i.e., heat pumps and electric forced-air furnaces), load control switches or PCTs are connected to a digital internet gateway. Load control switches allow the utility to cycle electric heating equipment on and off during peak events while PCTs automatically set back temperature setpoints on heating systems. For this analysis, two product options are offered:

- Bring-your-own-thermostat (BYOT) (for customers with existing PCT)
- Load control switches (for customers without existing PCT)

DLC programs have mandatory event participation once a customer elects to participate in the program. However, for the PCT product option, this analysis assumes that customers are able to opt out or override their participation in an event by readjusting their thermostat.

Input Assumptions

Table 40 lists the cost and impact assumptions that Cadmus used in estimating potential and levelized costs for the residential DLC space heat program.

Table 40. Residential Direct Load Control Space Heat Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	Assuming 1 FTE to set up the program.
O&M Cost	$ per participant per year	$7.50	The annual program administrative cost assumes 1 FTE at $150,000 per year per 20,000 residential participants. In PSE's 2015 CPA, admin costs were 5% of total costs and vendor costs were 15% of total costs (Cadmus 2015).
Equipment Cost	$ per new participant	BYOT: $0	BYOT: Because participant already has a PCT, no equipment cost is incurred.
		Switches: $215	Switches: Based on Applied (2017): $215 ($115 for the switch and $100 for installation). Other sources include Potter (2017): $166 (for the control technology, installation, and communication platform); Global (2011): $170; Navigant (2012): $370; Navigant (2015a) for central air-conditioning DLC: $125-$189 (including $60 switch); Xcel (2016) for central air-conditioning DLC: $150-$200 (equipment).
Marketing Cost	$ per new participant	$25	Range for DLC programs: Navigant (2012) $25; Applied (2017) $50; Brattle (2014) $80; Applied (2017) $50.
Incentives (annual)	$ per participant per year	$40	Assuming $10/month for the season (i.e., November to February). Applied (2017): $20; Navigant (2012): $32; Global (2011): $50.
Incentives (one time)	$ per new participant	$0	N/A
Attrition	% of existing participants per year	5%	Consistent with the residential DLC water heat program.
Eligibility	% of customer count (e.g. equipment saturation)	Varies by product option and segment	BYOT: The proportion of residential customers with a PCT (PSE's 2018 RCS) and have electric furnaces or air-source heat pumps (RBSA; heating zone 1). Switches: The proportion of residential customers without a PCT (PSE's 2018 RCS) and have electric furnaces or air-source heat pumps (RBSA; heating zone 1).
Peak Load Impact	kW per participant (at meter)	BYOT: 1.09	Based on 2021 Plan Workbook "Inputs_Product_ResBYOT-Winter" peak load impact assumption. Available at: https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655872907903
		Switches: 1.2	Based on 2021 Plan Workbook "Inputs_Product_ResHeatSwch-Winter" peak load impact assumption. Available at: https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655862892198
Program Participation	% of eligible customers	20%	Navigant (2012), Applied (2017), and Brattle (2016) use 20%. Global (2011) gives low- and high-range of 15% - 25%.
Event Participation	%	BYOT: 80%	BYOT: Customers can override the impact on their space heating by adjusting their PCTs (IPL 2014).

Parameters	Units	Values	Notes
		Switches: 94%	Switches: Space heat and central air-conditioning DLC programs for switch success rate range from 64% (Navigant 2012) to 96% (ConEd 2012; NIPSCO 2016). Using Cadmus (2013b) assumption.

Results

Table 41 shows that the residential DLC space heating program could, by 2045, obtain 53 MW of achievable potential in the winter. The switches option provides most of the achievable potential, at a levelized cost of $71 per kilowatt-year. Although it cannot provide much achievable potential, the bring-your-own-thermostat option is cheaper, at a levelized cost of $61 per kilowatt year.

Table 41. Residential Direct Load Control Space Heat Achievable Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed	Notification Type	Levelized Cost ($/kW-year)	24-Year Achievable Potential (MW)
Res DLC Heat-Switch	10 4-hour events	0-min	$71	50
Res DLC Heat-BYOT	10 4-hour events	0-min	$61	3

Residential Direct Load Control Water Heat

Water heating DLC programs directly control water heaters in customers' homes via load control switches. Communication between the utility and these switches can occur through advanced metering infrastructure (AMI) infrastructure, radio, consumer Wi-Fi connections to the internet, power line carrier, or paging infrastructure as well as through other web-based communications. Several other technologies, such as grid-enabled water heaters (GEWH) and water heater timers, exist for curtailing water heating energy usage during peak hours.

Product Options

All residential customers with electric storage water heaters are eligible to participate in the residential DLC water heat program. This analysis involves two product options for the residential DLC water heat program: load control switches and grid-enabled water heaters. However, considering the peak savings between electric-resistance water heaters (ERWH) and heat pump water heaters (HPWH) differ, this analysis split the eligible participants of these two product options between these two water heater types according to equipment saturations. The result was the following four product permutations for this simulated DLC water heat DR program:

- ERWH – Load control switches
- ERWH – GEWH
- HPWH – Load control switches
- HPWH - GEWH

For the switches class of product options, the utility installs the switch on customers' existing electric water heaters. This study assumed water heaters are cycled off for 50% of the event's duration. Because most electric water heaters use tank storage systems, which allow customers to draw on stored hot water during event times, the water heater load shifts on and off every 20 or 30 minutes during the event. The assessment assumes this product option will be available for four-hour duration events with up to 5 events per year.

The other class of product options is for customers who own GEWH. These water heaters are manufactured with an ANSI/CTA-2045 port that allows a universal communication device to be plugged in, enabling two-way connection to the utilities' grid infrastructure. The primary advantages of this built-in communication capability include the opportunity for greater participation in water heater DLC programs. These water heaters can also be controlled more often, potentially serving other utility grid needs.[8]

Washington State recently passed legislation that mandated electric storage water heaters manufactured on or after January 1, 2021, to comply with the modular demand response communications interface standard, ANSI/CTA–2045-A, or equivalent.[9] As a result, all new electric storage water heaters after 2021 will be GEWH and thus will be eligible for the GEWH product option. This analysis incorporates estimated impacts of this legislation by shifting most of the program participants to the GEWH products from the switch products over time for each water heater type.

Input Assumptions

Table 42 provides the cost and impact assumptions that Cadmus used in estimating potential and levelized costs for the residential DLC water heat program.

Table 42. Residential Direct Load Control Water Heat Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	Assuming 1 FTE to set up the program.
O&M Cost	$ per participant per year	$7.50	Assuming annual program O&M cost is 1 FTE at $150,000 per year per 20,000 residential participants.
Equipment Cost	$ per new participant	Switches: $315	Switches: Cadmus (2018) and Applied (2017). Range: Potter (2017) $350; Navigant (2015a): $106; Navigant (2012): $280 (space heat and water heat combined, additional $275 for gateway).
		GEWH: $40	GEWH: According to BPA (2018), communication device cost per tank will drop from $100 to $15 over 20 years as volume increases. Assuming $40 per tank (Eustis 2018).

8 Bonneville Power Administration. CTA-2045 Water Heater Demonstration Report. November 9, 2018. Available online: https://www.bpa.gov/EE/Technology/demand-response/Documents/Demand%20Response%20-%20FINAL%20REPORT%20110918.pdf

9 State of Washington. Second Substitute House Bill 1444, Certification of Enrollment. An act relating to appliance efficiency standards; amending RCW 19.260.010, 19.260.030, 19.260.040, 19.260.050, 19.260.060, and 19.260.070; reenacting and amending RCW 19.260.020; adding a new section to chapter 19.260 RCW; creating a new section; and repealing RCW 19.27.170. Passed April 18, 2019. http://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/House%20Passed%20Legislature/1444-S2.PL.pdf

Parameters	Units	Values	Notes
Marketing Cost	$ per new participant	$25	Range for DLC programs: Navigant (2012) $25; Applied (2017) $50; Brattle (2014) $80; Applied (2017) $50. According to BPA (2018), marketing cost per participant will drop from $150 to $25 over 20 years.
Incentives (annual)	$ per participant per year	$24	Assuming $2 per month for 12 months. Researched range: Applied (2017): $24-$25; Duke Energy (2015): $25; Navigant (2011): $8; BPA (2014): $4/month.
Incentives (one time)	$ per new participant	$0	N/A
Attrition	% of existing participants per year	5%	Cadmus (2011).
Eligibility	% of customer count (e.g., equipment saturation)	Varies by product option and segment	Electric water heat saturation was split between ERWH and HPWH based on RCS 2017 data. Ramp rate was adjusted to account for the growth in GEWH saturation over time. Methodology for ramp rate adjustment was informed by the 2021 Plan workbook "Inputs_Product_ResERWHDLCG-Winter". Available at: https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655867071789
Peak Load Impact	kW per participant (at meter)	ERWH: 0.58	ERWH: Cadmus (2015), Applied (2017), Navigant (2015a), and BPA (2014): 0.58 kW. Duke Energy (2015) 0.4 kW; Global (2011) 0.5 kW; Navigant (2011) 0.49 kW - 0.77 kW.
		HPWH: 0.24	HPWH: Based on weighted value from pilot results presented in March, 2018 (Eustis 2018).
Program Participation	% of eligible customers	Switches: 25%	Switches: Applied (2017) 15% - 23%; Global (2011) 15% - 25%; Navigant (2012) 20%; Navigant (2015a) 20% - 30% (realistic - max achievable).
		GEWH: 24%	GEWH: Based on BPA (2018) market transformation strategies. Program participation assumption adjusted down by half
Event Participation	% (switch success rate)	95%	Consistent with residential DLC space heat program.

Results

Table 43 presents assessment results for the residential DLC water heat program. The ERWH GEWH option could provide 58 MW of winter achievable potential by 2045, at a levelized cost of $81 per kilowatt-year. The ERWH load control switch option could add 11 MW of winter achievable potential at a levelized cost of $126 per kilowatt-year.

Table 43. Residential Direct Load Control Water Heat Achievable Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed	Notification Type	Levelized Cost ($/kW-year)	24-Year Achievable Potential (MW)
Res DLC ERWH-Switch	10 4-hour events	0-min	$126	11
Res DLC ERWH-Grid-Enabled	Unlimited	0-min	$81	58
Res DLC HPWH-Switch	10 4-hour events	0-min	$329	0.2
Res DLC HPWH-Grid-Enabled	Unlimited	0-min	$218	1

Commercial Critical Peak Pricing

The commercial CPP program is similar to the residential CPP program but for small and medium commercial customers.

Product Options

Commercial customers in the small or medium office or retail segments are eligible for the commercial DLC space heat program. Small office customers were defined as having a building square footage of less than 20,000, while medium office customers were those with a building square footage between 20,000 and 100,000. For retail, these square footage definitions were under 5,000 and between 5,000 and 50,000 for small and medium customers, respectively. According to existing program studies across the nation, peak load impacts achieved by CPP programs vary depending on if enabling technology such as PCTs are integrated with the program. This analysis estimated two product options within the commercial CPP program:

- No enablement (for customers without existing PCT)
- With enablement (for customers with existing PCT)

This analysis assumes that small and medium commercial customers with an existing PCT to control their electric space heating equipment (i.e., electric furnace or air-source heat pump) are eligible for the with-enablement option and can reduce 7% of their space heat load during a critical peak event, in addition to other end-use loads. All other small and medium commercial customers are eligible for the no-enablement product option and achieve a lower peak load impact.

Input Assumptions

Table 44 lists cost and impact assumptions that Cadmus used in estimating potential and levelized costs for the commercial CPP program.

Table 44. Commercial Critical Peak Pricing Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	Assuming 1 FTE to set up the program.
O&M Cost	$ per year	$75,000	SDG&E (2017): $280,000; Applied (2017): $75,000. Assuming 0.5 FTE.
Equipment Cost	$ per new participant	$0	No enablement: According to PSE (2018), AMI will be fully deployed in PSE's electric territory by 2023. Therefore, no equipment cost is incurred.
			With enablement: Because participant already has a PCT, no equipment cost is incurred.
Marketing Cost	$ per new participant	$50	Applied (2017): $50/new participant for small and medium commercial customers.
Incentives (annual)	N/A	$0	Program definition
Incentives (one time)	N/A	$0	Program definition
Attrition	% of existing participants per year	0%	N/A

Parameters	Units	Values	Notes
Eligibility	% of segment load	Varies by product option and segment	No enablement: The proportion of each segment's commercial customers that are not eligible for the with-enablement option.
			With enablement: The proportion of customers in small office, small retail, medium office, and medium retail with electric furnaces or air-source heat pumps (CBSA), assuming these customers have a PCT to control their heating load.
Peak Load Impact	% of eligible segment load	5%	No enablement: For small commercial customers, estimates ranged from 2.5% to 12.2% (Nexant 2017). For medium commercial customers, estimates ranged from 1.9% to 2.5% (Nexant 2017).
		7%	With enablement: Nexant (2017) reported 7% for participants with a PCT.
Program Participation	% of eligible segment load	10%	Assuming an opt-in program, estimates range from 2% (Cadmus 2015) to 18% (Applied 2017).
Event Participation	N/A	100%	Technical Potential already takes into account of event participation.

Results

Without any enabling technology, the commercial CPP program could obtain 1 MW of winter achievable potential by 2045 at $86 per kilowatt-year, as shown in Table 45. Participating customers with enabling technology can provide even more peak load reductions, and—because PSE does not pay for the existing enabling technology—they can provide the peak load reduction at a lower levelized cost, $81 per kilowatt-year.

Table 45. Commercial Critical Peak Pricing Achievable Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed	Notification Type	Levelized Cost ($/kW-year)	24-Year Achievable Potential (MW)
C&I CPP-No Enablement	10 4-hour events	Day-ahead	$86	1
C&I CPP-With Enablement	10 4-hour events	Day-ahead	$81	1

Commercial Direct Load Control Space Heat

Commercial DLC programs operate similarly to most residential DLC programs. In this commercial DLC space heat program, the utility directly reduces the electric space heating load of small and medium commercial buildings (in the office or retail segments) during event hours via load control switches. This analysis assumes four-hour events will be dispatched, with up to 5 events per winter season, using a cycling strategy of 50%. This means space heating equipment cycles off for 50% of an hour and remains on for 50% of an hour (i.e., 30 minutes off and 30 minutes on).

Program participants receive incentives at a yearly rate (though all payments may occur in the winter season), independent of the number and duration of events called. These incentives can be delivered through several applicable channels (e.g., bill credits, check incentives).

Product Options

Commercial customers in the small or medium office or retail segments with electric space heating (i.e., electric furnace or air-source heat pump) are eligible for the commercial DLC space heat program. This analysis involved two product options by eligible commercial segments:

- Small office and retail
- Medium office and retail

Input Assumptions

Table 46 lists cost and impact assumptions that Cadmus used in estimating potential and levelized costs for the commercial DLC space heat program.

Table 46. Commercial Direct Load Control Space Heat Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	Assuming 1 FTE to set up the program.
O&M Cost	$ per participant per year	$15	Assuming annual program O&M cost is 1 FTE at $150,000 per year per 10,000 small/medium commercial participants.
Equipment Cost	$ per new participant	Small: $387	Small: Applied (2017) for small C&I.
		Medium: $1,128	Medium: Applied (2017) for medium C&I.
Marketing Cost	$ per new participant	Small: $69	Small: Applied (2017) midpoint of $63-$75 for small C&I.
		Medium: $83	Medium: Applied (2017) midpoint of $75-$90 for medium C&I.
Incentives (annual)	$ per participant per year	Small: $38	Small: Applied (2017) for small C&I.
		Medium: $128	Medium: Applied (2017) for medium C&I.
Incentives (one time)	$ per new participant	$0	N/A
Attrition	% of existing participants per year	5%	Consistent with residential DLC programs.
Eligibility	% of customer count (e.g. equipment saturation)	Varies by segment	The proportion of customers in small office, small retail, medium office, and medium retail with electric furnaces or air-source heat pumps (CBSA).
Peak Load Impact	kW per participant (at meter)	Small: 1.87	Applied (2017) for WA for small and medium C&I (3.72 kW), adjusted to small C&I using a ratio of HVAC capacity sizes between small and medium C&I facilities (CBSA).
		Medium: 9.16	Applied (2017) for WA for small and medium C&I (3.72 kW), adjusted to medium C&I using a ratio of HVAC capacity sizes between small and medium C&I facilities (CBSA).
Program Participation	% of eligible customers	10%	Applied (2017): 2.3% - 3.4%; Global (2011): 10%; Brattle (2016): 14%; Navigant (2015a): 1-5%; and Brattle (2014): 15-42%.
Event Participation	% (switch success rate)	95%	Consistent with residential DLC programs.

Results

Table 47 presents results for the commercial DLC space heat program, which could provide 12 MW of winter load reduction by 2045, at a levelized cost of $64 per kilowatt-year for small office and retail buildings and $29 per kilowatt-year for medium office and retail buildings.

Table 47. Commercial Direct Load Control Space Heat Achievable Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed	Notification Type	Levelized Cost ($/kW-year)	24-Year Achievable Potential (MW)
Small Com DLC Heat-Switch	10 4-hour events	0-min	$64	7
Medium Com DLC Heat-Switch	10 4-hour events	0-min	$29	5

Commercial and Industrial Curtailment

For the commercial and industrial curtailment product, the utility requests that large commercial and industrial customers curtail their loads at a predetermined level for a predetermined period (i.e., the event duration). Event durations in similar programs across the country range from one hour to five hours. For this program, Cadmus assumes the event duration lasts four hours, and up to 5 events (for a total of 20 hours) could be called per season.

Participating customers execute curtailment after the utility calls the event. Customers may curtail any end-use loads to meet the curtailment agreement.[10] Although customers receive payments to remain ready for curtailment, actual curtailment requests may not occur. Therefore, this product represents a firm resource, and it assumes customers would be penalized for noncompliance. Because penalties exist, Cadmus assumes customers in the program will deliver a curtailed load that fulfills their contractual obligations 95% of the time (i.e., event participation).

Product Description

Cadmus assumes eligible participants include customers with at least 100 kW of monthly average demand in all commercial and industrial segments, excluding small office, small retail, medium office, and medium retail. The percentage of load represented by end-use customers meeting this requirement varies across commercial segments. Eligible customers can choose between two product options:

- Manual (where customers curtail loads during an event by manually turning off equipment)
- Automated (where customers install an automated control system that turns off certain pieces of equipment upon receiving the utility event dispatch signal)

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10 Cadmus assumed that participating customers could use standby generators to curtail load, similar to the assumption in Applied (2017).

Input Assumptions

Table 48 lists cost and impact assumptions that Cadmus used in estimating potential and levelized costs for the commercial and industrial curtailment program.

Table 48. Commercial and Industrial Curtailment Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	Assuming 1 FTE to set up the program.
O&M Cost	$ per kW pledged per year	$60	Based on Cadmus (2018). Applied (2017) $71/kW (including utility and vendor costs); other benchmarked values were $27/kW (Frontier 2016) and $3/kW (Idaho Power 2015), which Cadmus assumes only included utility administrative costs.
Equipment Cost	$ per new kW pledged	Manual: $0	Manual: Assuming end users have the necessary equipment to participate.
		Automated: $310	Automated: Potter (2017)'s automated demand response enablement cost for large commercial customers (>200 kW).
Marketing Cost	$ per new kW pledged	$0	Already included in vendor management costs: Cadmus (2018); Applied (2017); Cadmus (2013b); Cadmus (2015).
Incentives (Annual)	$ per kW pledged per year	$20	California utilities have incentives that range from $4/kW (SMUD 2017) to $12/kW (Christensen 2016). Incentives from non-California utilities included $10/kW (Cadmus 2018) and $20/kW (Idaho Power 2015).
Incentives (One Time)	$ per new kW pledged	$0	N/A
Attrition	% of existing participants per year	0%	N/A
Eligibility	% of segment/end-use load	Varies by segment	Eligible customer size ranges from 100kW (SDG&E 2017; PG&E 2017b) to 200kW (Cadmus' 2018 study for Snohomish County PUD; Freeman 2013). Cadmus used 100kW as the eligible customer size, consistent with PSE's 2015 study (Cadmus 2015). Eligibility percentages were calculated using PSE customer demand data (Cadmus 2015).
Peak Load Impact	% of eligible segment/end-use load	25%	Based on 2021 Plan Workbook "Inputs_Product_NRCurtailCom-Winter" peak load impact assumption. Available at: https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655869156072
Program Participation	% of eligible segment/end-use load	3%	Based on 2021 Plan Workbook "Inputs_Product_NRCurtailCom-Winter" program participation assumption. Available at: https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655869156072 Assume half of eligible participants would participate in the Manual option while the other half would participate in the AutoDR option.
Event Participation	%	Manual: 95%	Manual: Benchmarked event participation rates range from 52% (BPA 2012) to 95% (Cadmus 2018; BPA 2016; Cadmus 2015).
		Automated: 98%	Automated: Assuming higher than the manual option.

Results

As shown in Table 49, the commercial and industrial curtailment program could, by 2045, obtain 6 MW of winter achievable potential at $95 per kilowatt-year from the manual product option and a similar amount of potential at $127 per kilowatt-year from the automated product option.

Table 49. Commercial and Industrial Curtailment Achievable Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed	Notification Type	Levelized Cost ($/kW-year)	24-Year Achievable Potential (MW)
C&I Curtailment-Manual	10 4-hour events	Day-ahead (up to 2-hour-ahead)	$95	3
C&I Curtailment-AutoDR	10 4-hour events	0-min	$127	3

Residential Electric Vehicle Service Equipment

Residential EV charger demand response programs can be implemented to reduce EV charging in residential homes during peak hours. Networked level two EV chargers allow customers to better manage their EV charging and offer PSE some ability to control and track EV charging patterns.

Product Description

EV owners can charge their EVs at home, though not all are expected to have an installed level 2 charger. This study also assumes that most existing level 2 chargers are not networked. Therefore, this study focuses on EV owners that currently charge at home, but do not have a level 2 charger installed. The program would pay for the incremental cost of installing a connected level 2 charger. This study examines the potential of this program through the Residential EV DLC product option. Res EV DLC offers a financial incentive for residential EV owners to install a new networked level 2 charger and pays an annual incentive in exchange for curtailing EV charging loads during peak events. Connected level 2 chargers predominantly communicate via Wi-Fi or cellular service and can reduce 0% to 100% of output power in response to an event signal. This study assumes that events last up to four hours, for about 5 events during the winter.

Input Assumptions

Table 50 lists cost and impact assumptions that Cadmus used in estimating potential and levelized costs for the residential electric vehicle service equipment program.

Table 50. Residential Electric Vehicle Service Equipment Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	DLC: $150,000	Assuming 1 FTE to set up the program.
O&M Cost	$ per year	DLC: $150,000	Assuming 1 FTE.
Equipment Cost	$ per new participant	300	The Regional Technical Forum's researched incremental equipment cost of networked 240V level 2 charger compared to non-networked level 2 charger is $287 (Shum 2019).
Marketing Cost	$ per new participant	DLC: $30	City Light assumes this product requires higher marketing cost than the BPA assumption (Cadmus 2018a) for DLC products: $25 per new participant.
Incentives (Annual)	$ per participant per year	DLC: $25	In line with incentives for residential DLC space heat and cool products.
Incentives (One Time)	$ per new participant	$0	N/A
Attrition	% of existing participants per year	5%	In line with BPA assumption (Cadmus 2018a) for DLC products.

Parameters	Units	Values	Notes
Eligibility	% of customer count (e.g. equipment saturation)	36%	The number of EV owners is aligned with this study's assumptions for energy efficiency. The proportion of EV owners that already have a residential 240V AC level 2 charger (64%) is based on research by the Regional Technical Forum (Shum 2019).
Peak Load Impact	kW per participant (at meter)	0.34	Based on 2021 Plan Workbook "Inputs_Product_ResEVSEDLC-Winter" peak load impact assumption. Available at: https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655868985770
Program Participation	% of eligible customers	DLC: 25%	In line with assumptions for DLC products.
Event Participation	%	95%	Based on 2021 Plan Workbook "Inputs_Product_ResEVSEDLC-Winter" event participation assumption. Available at: https://nwcouncil.app.box.com/s/osjwinvjiomgo7vd4uc75y16z3x9b32i/file/655868985770

Results

As shown in Table 51, the residential electric vehicle service equipment program could, by 2045, obtain 9 MW of winter achievable potential at $361 per kilowatt-year.

Table 51. Residential Electric Vehicle Service Equipment Achievable Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed	Notification Type	Levelized Cost ($/kW-year)	24-Year Achievable Potential (MW)
Res EV DLC	10 4-hour events	Day-ahead	$361	9

Residential Behavioral

Residential behavior demand response encourages customers to save energy during peak day events through behavioral changes. Participants receive notice (via an email or automated phone message), which includes ways to save energy and reduce peak consumption. The notice is given 24 hours prior to an event. This product does not offer incentives but dispatches fewer events (for emergency use) compared to DLC products.

Product Description

This analysis modeled one product option based on benchmarked data and information from PGE's Flex Pricing and Behavioral Demand Response Pilot (Cadmus 2018c).

Input Assumptions

Table 52 lists cost and impact assumptions that Cadmus used in estimating potential and levelized costs for the residential behavioral program.

Table 52. Residential Behavioral Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	Assuming 1 FTE to set up the program.
O&M Cost	$ per kW pledged per year	$67	BPA assumption (Cadmus 2018) of $89/kW-year (or $4/participant) assumes implementing Res Behavior DR as a stand-alone product. However, Cadmus assumes it would cost $67/kW-year (or $3/participant)

Parameters	Units	Values	Notes
			to add Res Behavior DR to PSE's existing energy efficiency behavioral program.
Equipment Cost	$ per new kW pledged	$0	Participants must have a device to receive messages.
Marketing Cost	$ per new kW pledged	$0	Included in O&M costs.
Incentives (Annual)	$ per kW pledged per year	$0	In line with BPA assumption (Cadmus 2018a).
Incentives (One Time)	$ per new kW pledged	$0	In line with BPA assumption (Cadmus 2018a).
Attrition	% of existing participants per year	3.2%	PGE Flex Pricing and Behavioral Demand Response Pilot (Cadmus 2018c).
Eligibility	% of segment/ end-use load	100%	Assume all residential customers will have advanced meter by 2023
Peak Load Impact	% of eligible segment/end-use load	1.2%	PGE Flex Pricing and Behavioral Demand Response Pilot (Cadmus 2018c).
Program Participation	% of eligible segment/end-use load	20%	In line with BPA assumption (Cadmus 2018a).
Event Participation	%	100%	Peak load impact percentage accounts for event participation rate.

Results

As shown in Table 53, the residential behavioral program could, by 2045, obtain 9 MW of winter achievable potential at $76 per kilowatt-year.

Table 53. Residential Behavioral Achievable Potential and Levelized Cost

Product Option	Number of Events and Hours Curtailed	Notification Type	Levelized Cost ($/kW-year)	24-Year Achievable Potential (MW)
Res Behavior DR	10 4-hour events	Day-ahead (non-dispatchable)	$76	9

Section 3. Distributed Solar PV

Technical Potential Approach

Solar PV's technical potential depends on available areas suitable for PV installation and the power density of increasingly efficient PV arrays. Cadmus assessed these factors using the methods that follow.

Available Roof Area

We calculated the available roof area based on building square footage (RBSA[11] and CBSA[12]), number of floors (obtained from the CBSA), and a count of PSE customers. By dividing the overall square footage of each building category (single-family residential, K-12 school, etc.) by the number of floors, we estimated the roof area available for each type of building, as shown in Table 54. The estimated number of floors is an average, based on the number of floors reported by facility owners participating in the survey, rather than archetypal examples of each building type.

Table 54. Available Roof Area by Building Type

Building Type	Building Unit Floor Area (Square Feet)	Estimated Floors	Roof Area per Unit (Square Feet)	Customers in 2045
Large Office	229,882	12.0	19,085	2,708
Medium Office	41,759	3.1	13,404	11,599
Small Office	4,798	1.6	3,071	85,972
Extra Large Retail	280,351	1.4	196,246	139
Large Retail	94,426	1.4	66,098	537
Medium Retail	13,333	1.4	9,412	5,588
Small Retail	2,170	1.3	1,655	7,042
School K-12	36,550	1.6	23,100	3,458
University	121,328	1.6	76,679	2,599
Warehouse	34,314	1.5	22,529	6,957
Supermarket	49,734	1.3	37,300	1,749
Mini-Mart	2,116	1.1	1,996	1,202
Restaurant	9,727	1.2	8,447	8,772
Lodging	31,385	4.9	6,341	1,851
Hospital	80,979	2.0	39,803	366
Residential Care	89,214	2.0	43,851	358
Assembly	13,631	2.0	6,667	3,705
Other	22,415	2.0	10,964	19,507
Total Commercial				**164,109**
Single Family	1,284	1.6	934	752,283
Single Family Low Income	1,284	1.6	934	136,417
Multifamily Low Rise			371	231,646
Multifamily Low Rise Low Income			371	74,929
Multifamily High Rise			227	42,211
Multifamily High Rise Low Income			227	13,654
Manufactured	1,269	1.0	1,446	59,938

11 RBSA 2018 dataset of PSE oversample.

12 Based on CBSA 2014 data of all utilities within the "urban" subset.

Building Type	Building Unit Floor Area (Square Feet)	Estimated Floors	Roof Area per Unit (Square Feet)	Customers in 2045
Manufactured Low Income	1,269	1.0	1,446	33,158
Total Residential				**1,344,234**

Adjusted Available Area

The available raw area cannot be used directly to estimate technical potential because not every roof is suitable for solar PV. To account for factors such as unsuitable roof orientation, shading, and obstructions, Cadmus relied on PSE's 2017 assessment of potential that utilized Light Detection and Ranging (LIDAR) data from the National Renewable Energy Laboratory's (NREL's) rooftop solar PV technical potential study and filtered it to match PSE's service territory. In addition, Cadmus applied a reduction in available roof area due to Washington's adoption of the 2012 International Fire Code (IFC) Article 605.11.3, which requires that the minimum roof area be maintained for safe access by emergency personnel.[13] An addendum requires that PV arrays "shall be located no higher than 18 inches (457 mm) below the ridge in order to allow for fire department rooftop operations."[14] Although this is less stringent than similar codes adopted in California and other jurisdictions, it nevertheless limits the available roof area for installing PV modules. Cadmus estimated this would reduce the available square footage by 5% for residential applications. Table 55 provides the estimated technical constraints applied to each sector.

Table 55. Technical Constraints Assumptions by Sector

Sector/Building Type	Technical Constraints Assumptions
Residential	26% based on LIDAR data and IFC Article 605.11.3
Commercial	51% based on LIDAR data and IFC Article 605.11.3

Module Power Density

Cadmus determined the average module power density in the PSE region through a review of installed PV system data provided by PSE. Using model number lookups for modules installed in 2018 and 2019, we determined the 2018 average module watts per square foot. Cadmus estimated future module power density using the trends in module efficiency increases from the International Roadmap for Photovoltaic. [15] Module power density in 2018 was 17.3 W_p/square foot, the estimated power density in 2022 is 18.5 W_p/square foot and the estimated power density in 2045 is 21.1 W_p/square foot.

13 Washington State Department of Enterprise Services, State Building Code. https://fortress.wa.gov/ga/apps/sbcc/Page.aspx?nid=14

14 Ibid.

15 International Technology Roadmap for Photovoltaic. https://itrpv.vdma.org/web/itrpv/download

Electricity Generation

Once the potential solar PV direct current capacity was established, we converted this figure into annualized electricity (kilowatt-hour) generation. To approximate the generation profile of a typical PV system in PSE's service territory, Cadmus calculated an average capacity factor in kWh/kW_{DC} from the PSE's 2020 solar production database. The result is an average electricity generation figure, normalized to installed capacity, which accounts for specific regional characteristics for PSE's service territory.

Achievable Potential Approach

After calculating the technical potential that provides a theoretical upper bound on PV capacity growth, Cadmus considered relevant market factors (e.g., current costs, projected future cost trends, past adoption) to determine likely PV growth for PSE's service territory. To assess achievable potential, Cadmus first examined sector, end-use load, and customer economics for PV adoption in terms of simple payback. We applied these metrics to calculate achievable potential for two policy-based scenarios, considering the impacts of federal tax credits, incentives, and policies. The examination included the following scenarios:

- **Business-as-Usual Scenario.** This scenario reflects the base case with all current policies and incentives locked in place as written, including incentive amounts, expiration dates, and similar characteristics. Although this may not represent the most realistic scenario, this can provide a strong baseline for considering policy alternatives and planning scenarios. This includes several key policies:
  - Federal Investment Tax Credit: The ITC provides a 30% PV tax credit through 2019, with 26% in 2020, 22% in 2021, and expiring on December 31, 2021 for residential PV but reduced to 10% for commercial building PV thereafter.
  - Washington State Sales Tax Exemption: Solar PV equipment was exempt from a 6.5% Washington State Sales Tax. This benefit expired on September 30, 2017 and is not included in the business-as-usual scenario.
  - Washington State Renewable Energy System Cost Recovery Program (Production Incentive): The Production Incentive provided a variable, production-based incentive up to $5,000 per year for PV systems. The incentive level ranged from $0.15/kWh to $0.54/kWh, depending on the customer's eligibility for a variety of incentive adders (e.g., using equipment manufactured in Washington). PSE terminated this incentive December 12, 2019 and it is also not included in this study.
- **Advanced Cost Decline Scenario.** This scenario models a more rapid rate of cost decline while maintaining all the same financial incentives as the Business-as-Usual scenario. The cost decline is based on NREL's 2020 Annual Technology Baseline's[16] (ATB) advanced cost forecast compared to the moderate cost forecast used in the business-as-usual scenario.

[16] NREL provides an annual set of modeling input assumptions for energy technologies, known as the Annual Technology Baseline, including residential and commercial PV. Available online: https://atb.nrel.gov

Customer payback. A metric commonly used in selling energy efficiency and renewable energy technologies, annualized simple payback (ASP) is a simplistic calculation that customers can easily and intuitively understand and provides a key factor in their financial decision-making processes. For this analysis, Cadmus calculated simple payback using the following equation:

$$ASP = \frac{Net\ Costs\ (after\ incentives)}{Annual\ Energy\ Savings + Production\ Incentive\ Payments - Annual\ O\&M}$$

Although this equation is conceptually simple, the mix of incentives and cost projections added complexity to the calculations.

Installed costs. Cadmus based these assumptions of installed PV system costs on a variety of public data sources. Cadmus reviewed cost forecasts of both residential and commercial solar installations. These costs do not include any incentives, they are based on full costs of an installation. The PV $/Watt cost estimates for this study were developed from three major sources:

- 2020 EnergySage reported costs for installed residential solar PV systems in Washington state[17]
- 2020 Wood Mackenzie U.S. Solar Market Insight Full Report, 2019 Year in Review for nation-wide commercial solar PV systems[18]
- 2020 NREL ATB forecasts for residential- and commercial-scale PV pricing estimates to 2050[19]

Cadmus used a combination of these sources to validate and forecast $/watt. The projected installed dollar per watt is shown in Figure 42 over the planning horizon.

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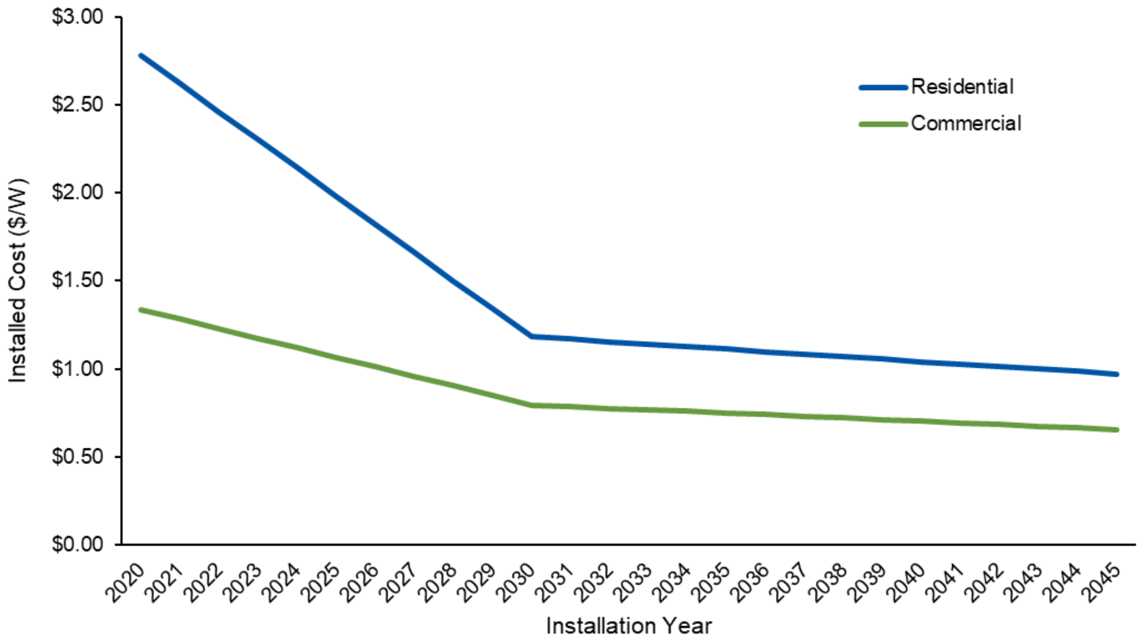
17 EnergySage is an online marketplace for residential solar installations that gathers real quotes from installers. This online marketplace was used to validate solar prices. EnergySage available online: https://www.energysage.com/solar-panels/solar-panel-cost/wa/

18 Wood Mackenzie, U.S. Solar Market Insight Full Report, 2019 Year in Review, March 2020. Available online: https://www.woodmac.com/reports/power-markets-us-solar-market-insight-2019-year-in-review-395500

19 NREL provides an annual set of modeling input assumptions for energy technologies, known as the Annual Technology Baseline, including residential and commercial PV. Available online: https://atb.nrel.gov

Figure 42. Projected Installed PV Costs by Sector (2020-2045)



Market penetration rates. Predicting which portion of technically feasible sites will install PV systems during the assessment period is a complex process, driven by many policy, economic, and technical factors beyond the direct control of PSE. These factors can be effectively modeled using their impacts on a quantitative metric (such as customer simple paybacks) and run for a variety of prototypical scenarios.

This model estimates (a percentage of) market penetration as a function of customer payback. The following equation provided the curve used in analysis:

$$MP = A*e^{-B*ASP}$$

where MP equals the percentage of market adoption, and ASP equals the annual simple payback (years).

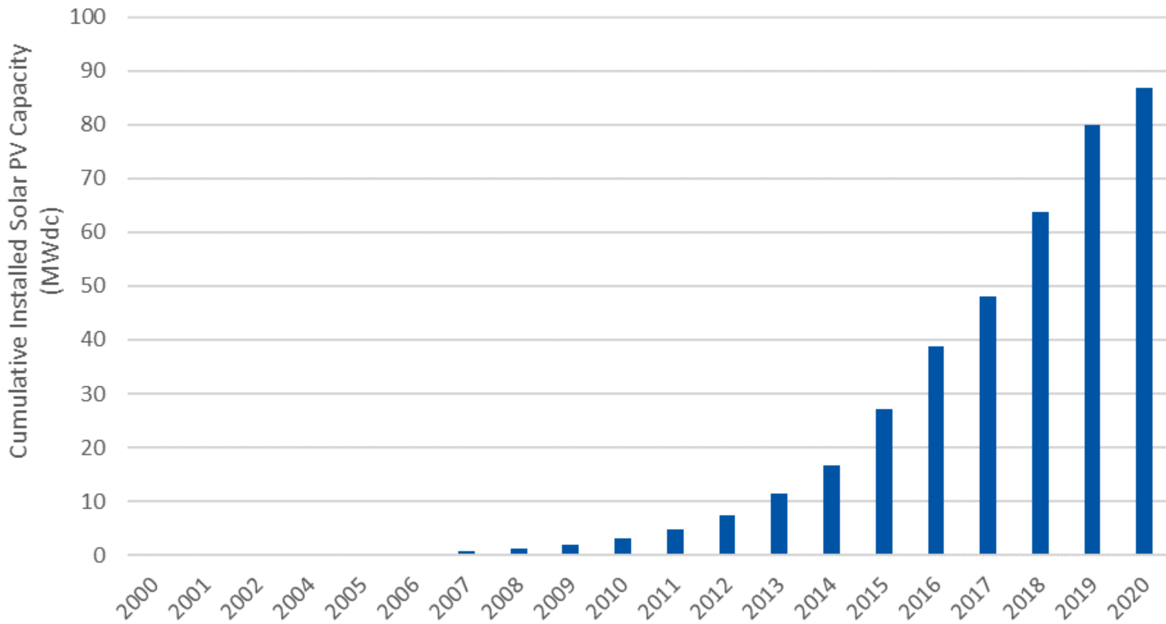
For this analysis, Cadmus calculated ASP from the end-use customers' perspectives, including all relevant incentives and fitting the curve to historical adoption rates. This curve-fitting process allowed Cadmus to account for, broadly speaking, regional attitudes and bias that might lead end-use customers to adopt solar at a given ASP level (the above equation shows these empirical factors as A and *B).*

After running the two scenarios of the plausible ranges in achievable potential, Cadmus relied on the base scenario to represent most realistic and current rate adoption. We used hourly profiles based on NREL's PVWatts calculator for the residential, commercial, and industrial sectors combined with the achievable base scenario potential to determine the PSE's IRP 8760 inputs.

Historical Solar PV Installations

As previously noted, the study estimated solar PV market potential for new installations from 2022 through 2045. This potential is in addition -- not inclusive of – the amount of solar PV capacity previously installed by customers in PSE's service territory. Figure 43 provides the cumulative installed solar PV capacity from 2000 through the first six months of 2020. Overall, the cumulative installed capacity is equal to 87 MW_{dc}. Nearly 60 MW, or 69% of the total, have been installed since 2016.

Figure 43. Historical Solar PV Installed Capacity, MW_{dc} through 2020



Distributed Solar PV Potential

Technical Potential Results

Based on the analysis described in the previous sections, Cadmus estimated 22,330 MW as the total new technical potential for PV installed on residential and commercial rooftops in PSE's service area over the 24 year study horizon. 71% of this technical potential arose in the commercial sector with the remaining 29% came from the residential sector. Each sector's technical potential is a function of the fraction of total roof area available and the total roof area. In this case, the residential sector accounted for a smaller percentage of the technical potential because only a modest proportion of total available area for this sector is likely to be suitable for PV installations. If the full technical potential were installed, it would generate approximately 2,362 aMW. This estimate derives from specific capacity factors for PSE (0.117 for residential and commercial), calculated using PSE's 2020 solar production database.

Table 56 provides the study period behind-the meter PV technical potential with growth due to increases in building stock from 2022 to 2045.

Table 56. PV Technical Potential (2022-2045)

Sector	Total 2022 aMW	Installed Capacity 2022 MW	Total 2045 aMW	Installed Capacity 2045 MW
Residential	534	4,560	697	6,584
Commercial	1,305	11,142	1,665	15,746

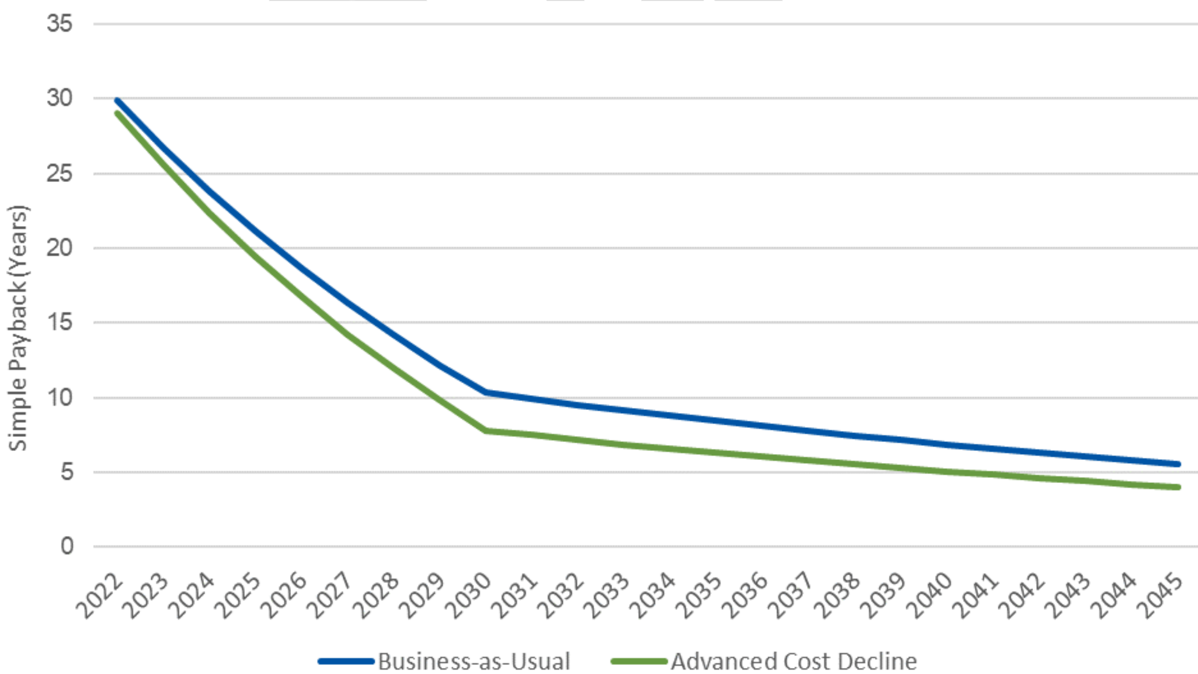
Sector	Total 2022 aMW	Installed Capacity 2022 MW	Total 2045 aMW	Installed Capacity 2045 MW
Total	**1,840**	**15,701**	**2,362**	**22,330**

Achievable Potential Results

Historically, the PV market has been heavily influenced by policy and incentive decisions, but, over time, future incentives may play a lesser role. For example, projects continue to be completed in California, even though major incentives have ended, and more projects continue to be completed under the Federal Public Utility Regulatory Policies Act. To model the influence of this policy shift away from incentives on the PV market potential within PSE's territory, Cadmus developed two scenarios reflecting the impact of only changes in upfront capital costs on customer paybacks and, by extension, market potentials. Unsurprisingly, the rate of decline in system capital cost heavily influences PV's achievable potential. In this section, Cadmus summarizes the results for each scenario (the business-as-usual and the advanced cost decline scenario).

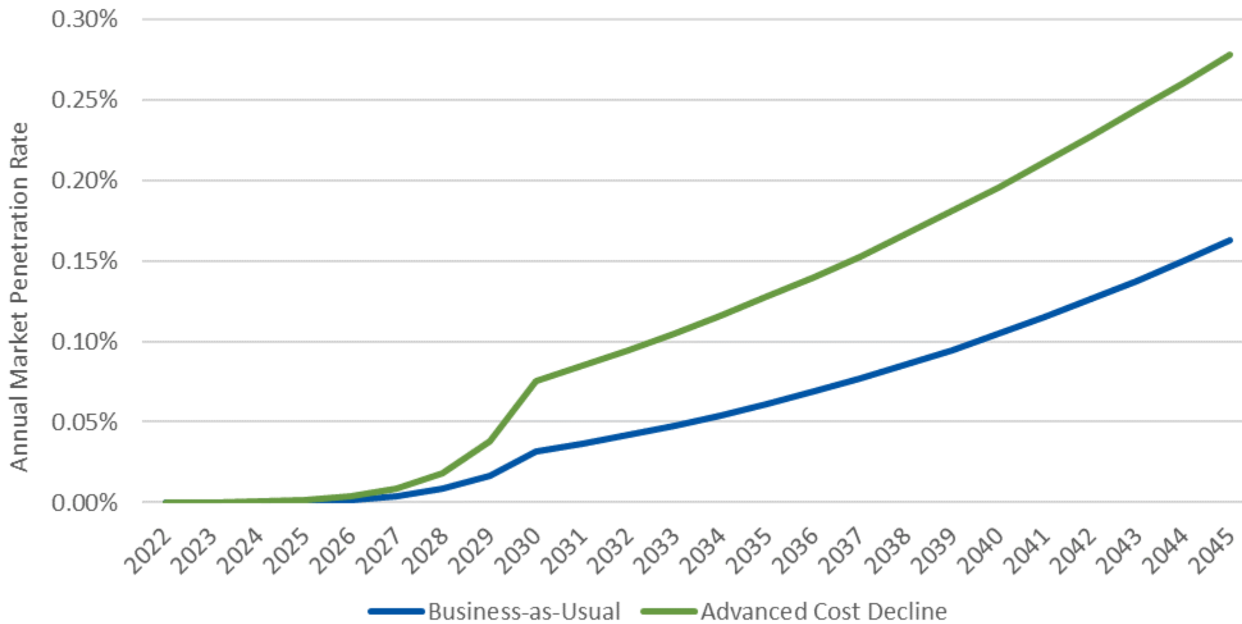
Figure 44 shows the impact of these scenario choices on expected customer payback periods (residential). The business-as-usual scenario shows a payback period of 30 years at the beginning of the study period and dropping to 6 years by 2045 primarily due to lower capital costs. The advanced cost decline scenario drops from a 29-year payback period in 2022 to 4 years in 2045.

Figure 44. Residential PV Simple Payback Projections Under Two Policy Scenarios



As a result, these varying payback periods have an impact on the likely adoption of PV systems. As discussed in the PV Achievable Potential Approach, Cadmus modeled a percentage of market penetration as a function of customer payback. Figure 45 shows the annual market penetration rate for the residential sector of each adoption scenario. Having lower PV costs is a major driver to increased market adoption.

Figure 45. Residential PV Annual Market Penetration Rate Under Two Policy Scenarios



Overall, across PSE's service area (residential and commercial), achievable potential will grow steadily year by year under both adoption scenarios, as shown in Figure 46. The advanced cost decline scenario results in achievable technical potential in 2045 of over 1.8 times that of the business-as-usual scenario.

Figure 46. Solar PV Total Cumulative Achievable Potential by Scenario

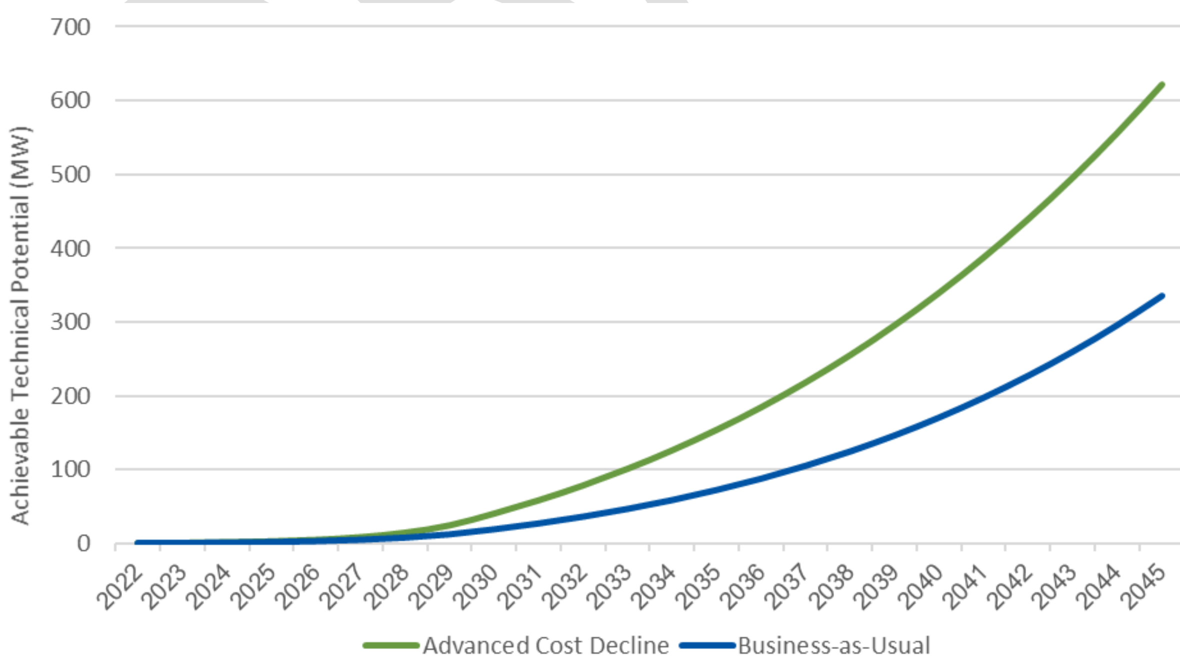


Table 57 summarizes the achievable potential results for each scenario. Cadmus relied on the business-as-usual scenario to represent the most realistic adoption rate for the IRP.

Table 57. Achievable Potential Results by Scenario and Sector, 2045 MW

Scenario	Residential MW	Commercial MW	Total MW
Business-as-Usual	87	249	336
Advanced Cost Decline	165	457	622

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Appendix A. IRP Sensitivities

This appendix provided comparisons of various electric and natural gas IRP sensitivies to the base case potentials presented throughout this report.

Electric IRP Sensitivities

Following engagements with stakeholders, PSE requested Cadmus to create four additional sensitivity scenarios for electric measures. The scenarios included are:

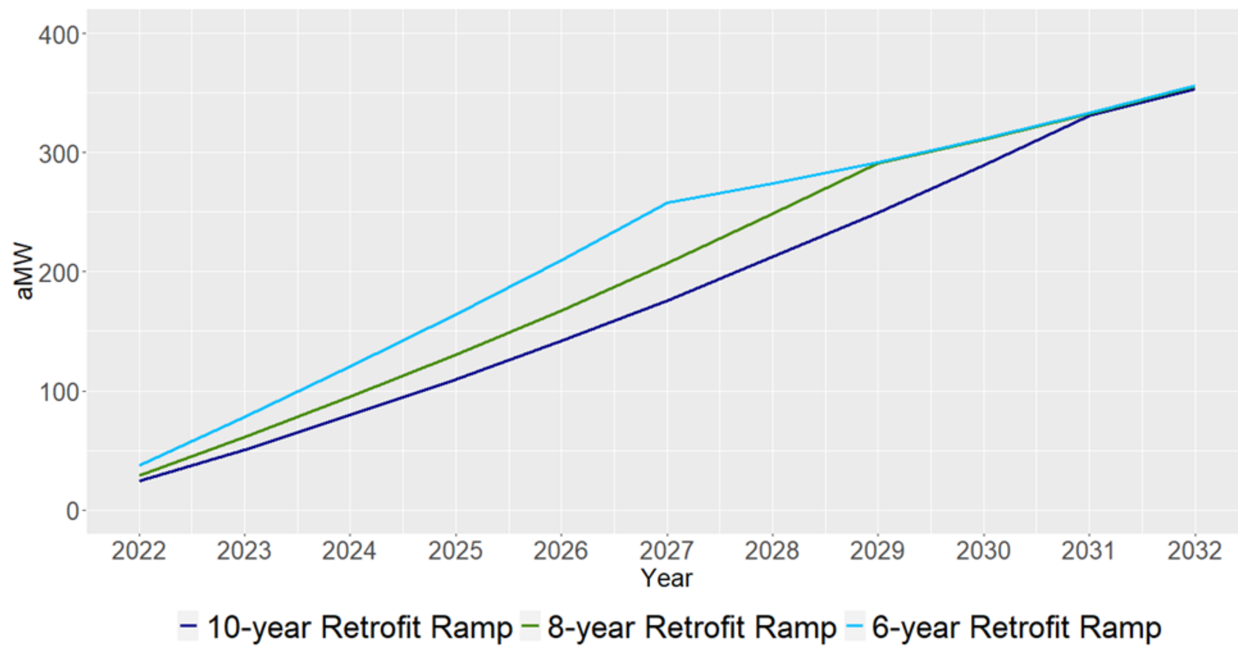
- **The 6-Year Retrofit Ramp Scenario** estimates potential using an accelerated ramp rate for discretionary measures, so all discretionary potential is obtained in the first 6 years of the study.
- **The 8-Year Discretionary Ramp Scenario** estimates potential using an accelerated ramp rate for discretionary measures, so all discretionary potential is obtained in the first 8 years of the study.
- **Societal Discount Rate Adjusted Scenario** utilizes a discount rate of 2.5%.
- **Non-energy Impact Adjusted Scenario** calculates the non-energy impact based on the EPA estimate for the cost of non-energy impacts of $0.02/kWh. [20]

Cadmus compared the results of these scenarios to the base scenario, with a 10-year retrofit ramp rate, to determine the impact of the scenarios on overall electric energy efficiency achievable potential.

Figure A-1 shows the impact of the differing ramp rate scenarios on the distribution of the cumulative energy efficiency achievable potential over the first ten years of the potential study.

[20] The Environmental Protection Agency estimates the per kWh non-energy benefits to be 2 cents for the PNW region.

Figure A-1. 10-Year Cumulative Energy Efficiency Achievable Potential (aMW)



The differing ramp rates for discretionary measures result in 43% of the 24-year electric achievable energy efficiency potential being achieved in the first 6 years and 48% of the 24-year electric achievable energy efficiency potential being achieved in the first 8 years**.** It is important to note that the 24-year cumulative electric achievable energy efficiency potential is equivalent across all scenarios and the differing ramp rates only have an impact on the distribution of the potential within the potential study horizon.

Table A-1 provides a comparison of the 6-year cumulative achievable potential from the base scenario with a 10-year retrofit ramp rate to the scenario with a 6-year retrofit ramp rate.

Table A-1. Comparison of 6-Year Electric Energy Efficiency Cumulative Achievable Potential for IRP Sensitivity Ramp Rate Scenarios (aMW)

Year	10-year Retrofit Ramp Achievable Potential (aMW)	6-year Retrofit Ramp Achievable Potential (aMW)	Percent Change Compared to 10-year Retrofit Ramp
2027	176.09	257.59	46.3%

In the first 6 years of the potential study, 176 aMW of cumulative achievable potential is obtained in the base scenario. In the 6-year retrofit ramp rate scenario, the cumulative achievable potential in the first six years is 46% greater with a value of 256 aMW.

Table A-2 provides a comparison of the 8-year cumulative achievable potential from the base scenario with a 10-year retrofit ramp rate to the scenario with an 8-year retrofit ramp rate.

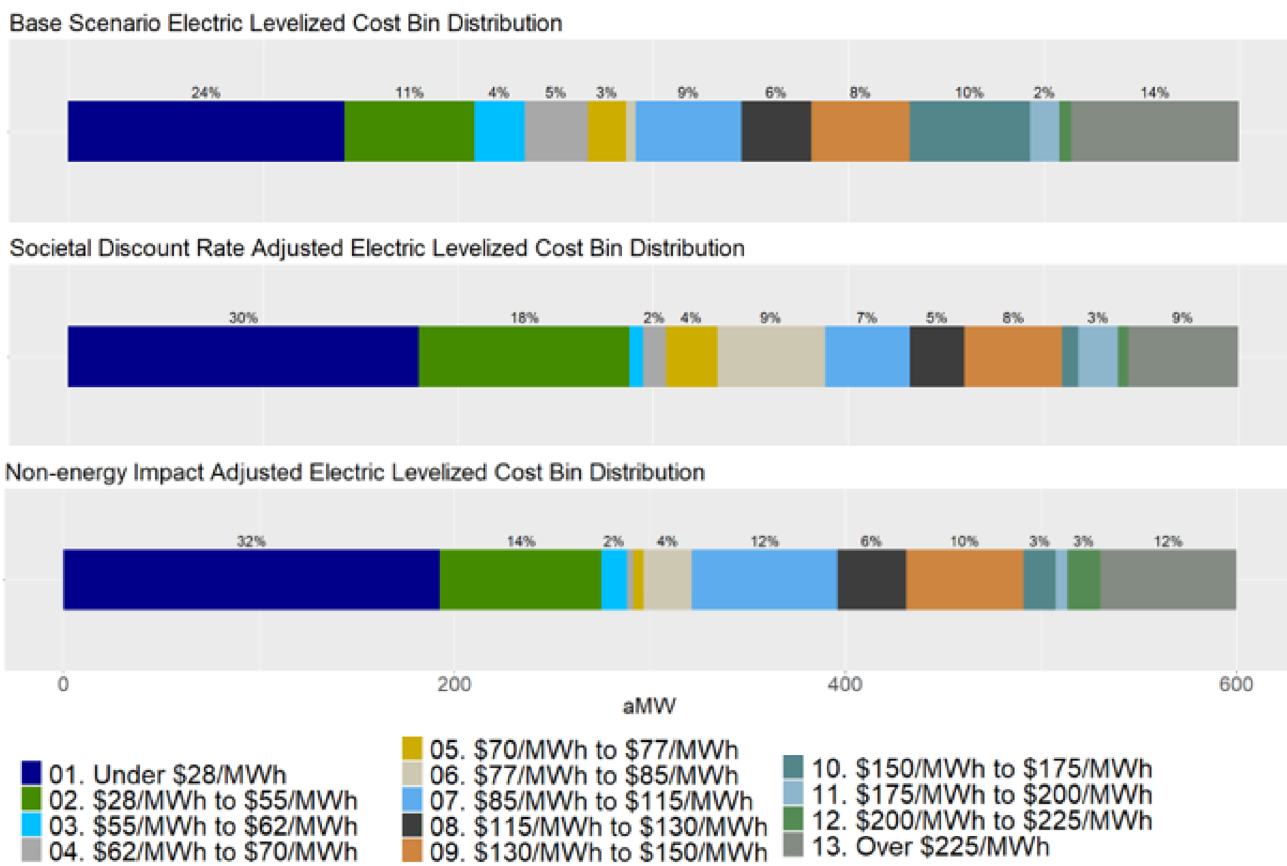
Table A-2. Comparison of 8-Year Electric Energy Efficiency Cumulative Achievable Potential for IRP Sensitivity Ramp Rate Scenarios (aMW)

Year	10-year Retrofit Ramp Achievable Potential (aMW)	8-year Retrofit Ramp Achievable Potential (aMW)	Percent Change Compared to 10-year Retrofit Ramp
2029	249.68	290.86	16.5%

In the first 8 years of the potential study, 250 aMW of cumulative achievable potential is obtained in the base scenario. In the 8-year retrofit ramp rate scenario, the cumulative achievable potential in the first eight years is 17% greater with a value of 291 aMW.

Figure A-2 shows the impact of the societal discount rate adjusted scenario and the non-energy impact adjusted on the electric levelized cost bin distribution when compared to the base scenario. Note that the base scenario has a discount rate of 6.8%.

Figure A-2. Comparison of Levelized Cost Bin Distribution for 24-Year Cumulative Achievable Potential in IRP Sensitivity Scenarios (aMW)



The non-energy impact adjusted scenario and the societal discount rate adjusted scenario have 13% and 11%, respectively, more of the 24-year cumulative electric achievable potential with a levelized cost under $55/MWh. This equates to about 80 and 67 more aMW, respectively, of 24-year cumulative achievable potential than the base scenario under $55/MWh. Additionally, in the societal discount rate adjusted and the non-energy benefit adjusted scenarios, the cost bin designated by a levelized cost greater than $225/MWh is reduced by 56 aMW and 69 aMW, respectively, and is no longer the second largest bin.

Gas IRP Sensitivities

PSE requested Cadmus to create four additional sensitivity scenarios for natural gas measures. The scenarios included are:

- **The 6-Year Retrofit Ramp Scenario** estimates potential using an accelerated ramp rate for discretionary measures, so all discretionary potential is obtained in the first 6 years of the study.
- **The 8-Year Discretionary Ramp Scenario** estimates potential using an accelerated ramp rate for discretionary measures, so all discretionary potential is obtained in the first 8 years of the study.
- **Societal Discount Rate Adjusted Scenario** utilizes a discount rate of 2.5%.

Cadmus compared the results of these scenarios to the base scenario, with a 10-year retrofit ramp rate, to determine the impact of the scenarios on overall natural gas energy efficiency achievable potential.

Figure A-3 shows the impact of the differing ramp rate scenarios on the distribution of the cumulative energy efficiency achievable potential over the first ten years of the potential study.

Figure A-3. 10-Year Cumulative Energy Efficiency Achievable Potential (Therms)

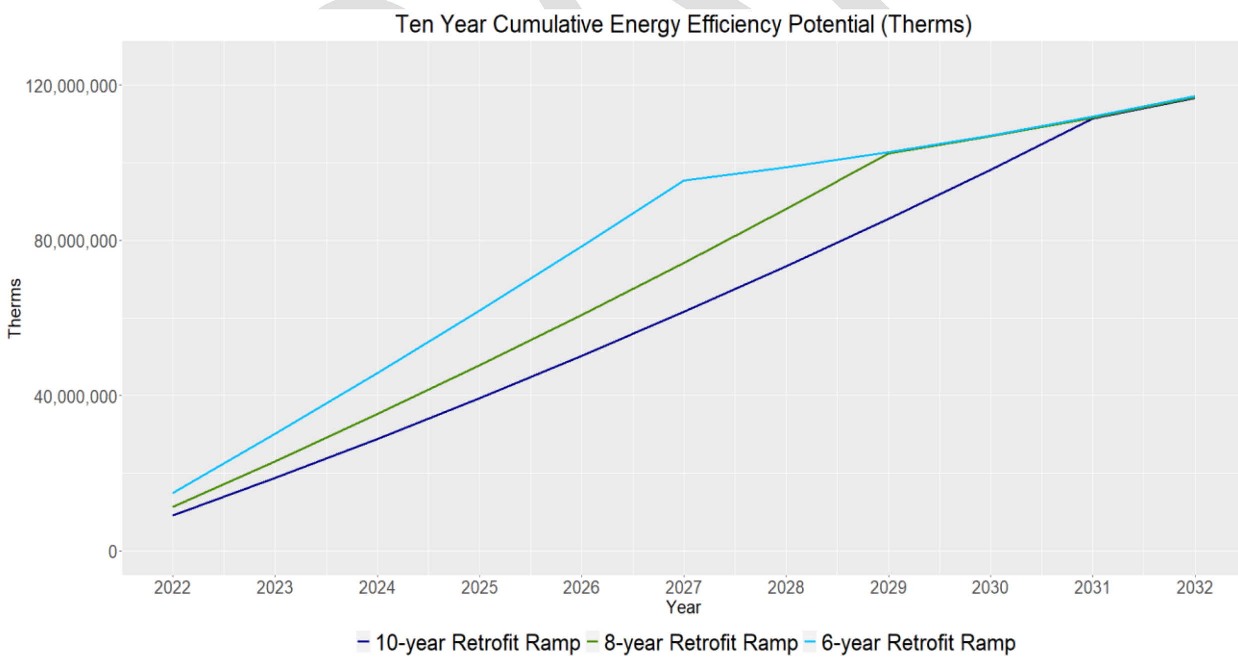


Table A-3 provides a comparison of the 6-year cumulative achievable potential from the base scenario with a 10-year retrofit ramp rate to the scenario with a 6-year retrofit ramp rate.

Table A-3. Comparison of 6-Year Natural Gas Energy Efficiency Cumulative Achievable Potential for IRP Sensitivity Ramp Rate Scenarios (Therms)

Year	10-year Retrofit Ramp Achievable Potential (Therms)	6-year Retrofit Ramp Achievable Potential (Therms)	Percent Change Compared to 10-year Retrofit Ramp
2027	61,576,169	95,411,744	54.9%

In the first 6 years of the potential study, 61.6 million therms of cumulative achievable potential are obtained in the base scenario. In the 6-year retrofit ramp rate scenario, the cumulative achievable potential in the first six years is 54.9% greater with a value of 95.4 million therms.

Table A-4 provides a comparison of the 8-year cumulative achievable potential from the base scenario with a 10-year retrofit ramp rate to the scenario with an 8-year retrofit ramp rate.

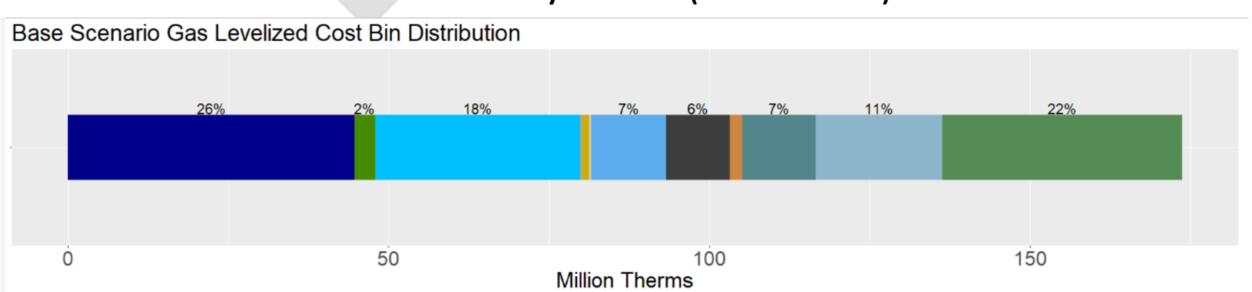
Table A-4. Comparison of 8-Year Natural Gas Energy Efficiency Cumulative Achievable Potential for IRP Sensitivity Ramp Rate Scenarios (Therms)

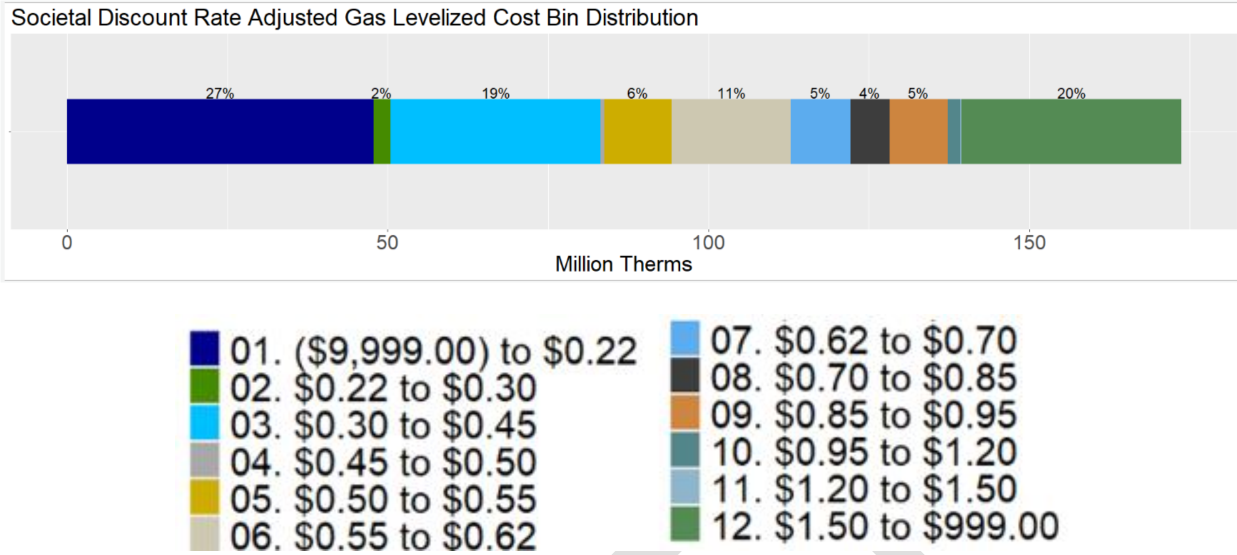
Year	10-year Retrofit Ramp Achievable Potential (Therms)	8-year Retrofit Ramp Achievable Potential (Therms)	Percent Change Compared to 10-year Retrofit Ramp
2029	85,553,452	102,425,509	19.7%

In the first 8 years of the potential study, 85.6 million therms of cumulative achievable potential is obtained in the base scenario. In the 8-year retrofit ramp rate scenario, the cumulative achievable potential in the first eight years is 19.7% greater with a value of 102.4 million therms.

Figure A-4 shows the impact of the societal discount rate adjusted scenario on the natural gas levelized cost bin distribution when compared to the base scenario. Note that the base scenario has a discount rate of 6.8%. When the societal discount rate is used the amount of cumulative 20-year achievable potential in the least expensive cost bin increases by one percent and the highest cost bin potential decreases by a percent compared to the base scenario. The greatest change in levelized cost bin distribution occurs across cost bins five to eleven (levelized costs $0.50 - $1.50). In the societal discount rate scenario, there is more cumulative achievable potential in the lower of these cost bins compared to the base scenario.

Figure A-4. Comparison of Levelized Cost Bin Distribution for 20-Year Cumulative Achievable Potential in IRP Sensitivity Scenarios (Million Therms)





Cost bins that make up less than 2% of the 20-Year Cumulative Achievable Potential are not labeled on the horizontal bar charts

F

Demand Forecasting Models

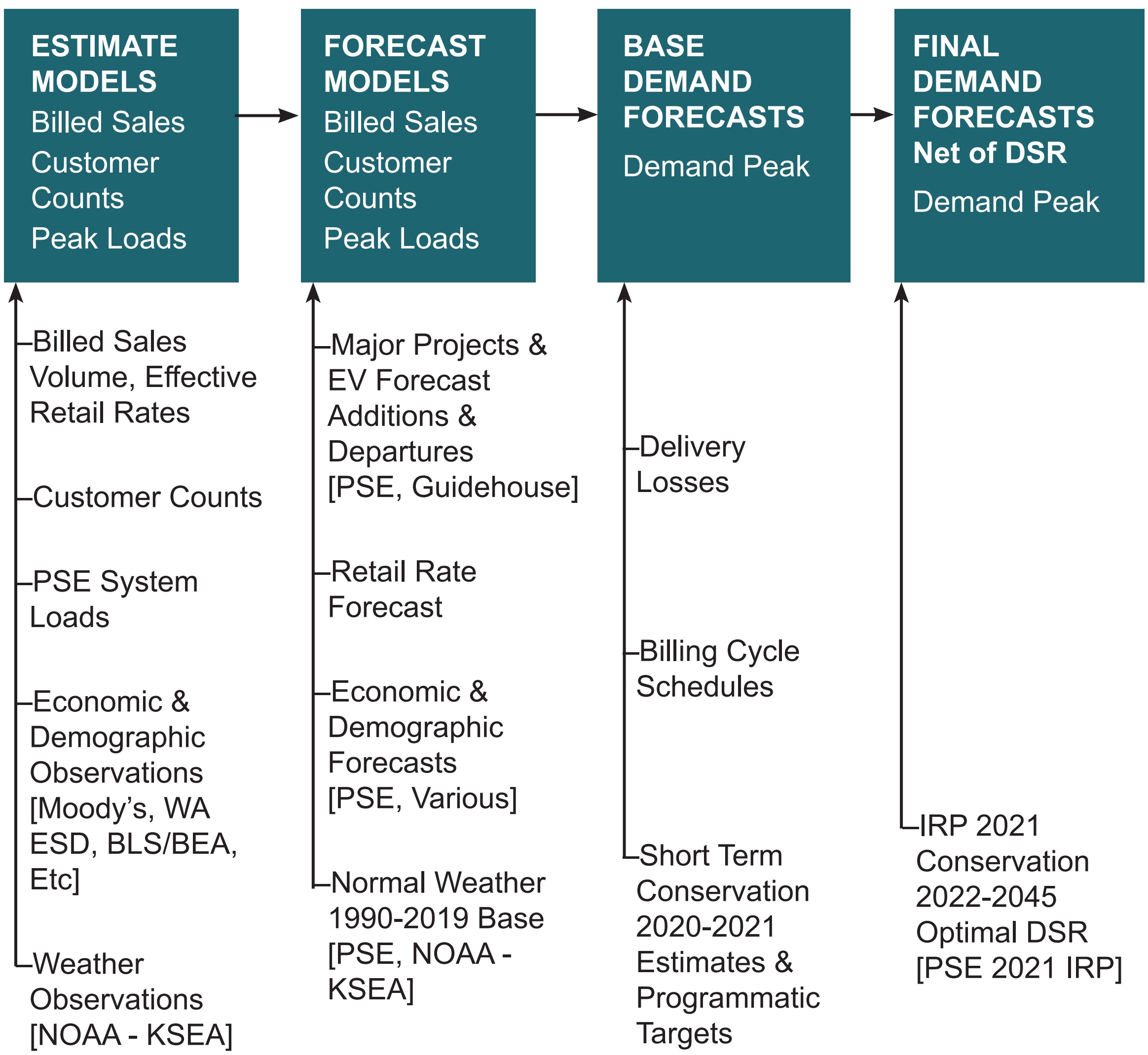
This appendix describes the econometric models used in creating the demand forecasts for PSE's 2021 IRP analysis.

Contents

1. THE DEMAND FORECAST

PSE employs time series econometric methods to forecast monthly energy demand and peaks for PSE's electric and gas service territories. PSE gathers observations of sales, customer counts, demand, weather and economic/demographic variables to estimate models of use per customer (UPC), customer counts and peaks. Once model estimation is complete, PSE utilizes internal and external forecasts of new major demand (block sales), retail rates, economic/demographic drivers, normal weather and programmatic conservation to create a 20-year projection of monthly demand and peaks. The 2021 IRP Base Demand Forecast for energy reflects committed, short-term programmatic conservation targets; the 2021 IRP Base Demand net of demand-side resources (DSR) additionally reflects the optimal DSR chosen in the 2021 IRP analysis. The following diagram depicts the demand forecast development process:

Figure F-1: Demand Forecast Development Process Flow



Model Estimation

To capture incremental customer growth and temperature/economic sensitivities, PSE forecasts billed sales by estimating use per customer (UPC) and customer count models. The models are disaggregated into the following major classes and sub-classes (or sectors, as determined by tariff rate schedule) in order to best estimate the specific driving forces underlying each class.

- Electric: residential, commercial (high-voltage interruptible, large, small/medium, lighting), industrial (high-voltage interruptible, large, small/medium), streetlights and resale
- Gas: firm classes (residential, commercial, industrial, commercial large volume and industrial large volume), interruptible classes (commercial and industrial) and transport classes (commercial firm, commercial interruptible, industrial firm and industrial interruptible).

Each class's historical sample period ranges from, at earliest, January 2003 to December 2019.

> > > See Chapter 6, Demand Forecasts, *for discussion of the development of economic/demographic input variables.*

Customer Counts

PSE estimates monthly customer counts by class and sub-class. These models use explanatory variables such as population, employment (both total and sector specific), and unemployment. Larger customer classes are estimated via first differences, with economic and demographic variables implemented in a lagged or polynomial distributed lag form to allow delayed variable impacts. Some smaller customer classes are not estimated, and instead held constant. ARMA(p,q) error structures are also imposed, subject to model fit.

The estimating equations for **customer counts** are specified as follows:*

$$CC_{C,t} = \boldsymbol{\beta_C}\left[\propto_C \quad \boldsymbol{D}_{M,t} \quad T_{C,t} \quad \boldsymbol{ED}_{C,t}\right] + u_{C,t},$$

where:

Customer Count ("$CC_{C,t}$")	=	Count of customers in Class/sub-class "C" and month "t"
Class ("C")	=	Service and class/sub-class, as determined by tariff rate
Time ("t")	=	Estimation time period $\{DateStart_C \ldots .2019M09\}$
Regression Coefficients ("$\boldsymbol{\beta_C}$")	=	Vector of CC_C regression coefficients estimated using Conditional Least Squares/ARMA methods
Constant ("$\propto_C$")	=	Indicator variable for class constant (if applicable)
Date Indicator ("$\boldsymbol{D}_{M,t}$")	=	Vector of month/date specific indicator variables
Trend ("$T_{C,t}$")	=	Trend variable (not included in most classes)
Economic/Demographic Variables ("$\boldsymbol{ED}_{C,t}$")	=	Vector of economic and/or demographic variables
Error term ("$u_{C,t}$")	=	ARMA error term (ARMA terms chosen in model selection process)

** The term vector or boldface type denotes one or more variables in the matrix.*

Use Per Customer

Monthly use per customer (UPC) is estimated at class and sub-class levels using explanatory variables including degree days, seasonal effects, retail rates, average billing cycle length, and various economic and demographic variables such as income and employment levels. Some of the variables, such as retail rates and/or economic variables, are modelled in a lagged form to account for both short-term and long-term effects on energy consumption. Finally, depending on the equation, an ARMA(p,q) error structure is employed to address issues of autocorrelation. The estimating equations for **use per customer** are as follows:*

$$\frac{UPC_{C,t}}{D_{c,t}} = \boldsymbol{\beta_C}\left[\propto_C \quad \frac{\boldsymbol{DD}_{C,t}}{D_{C,t}} \quad \boldsymbol{D}_{M,t} \quad T_{C,t} \quad \boldsymbol{RR}_{C,t} \quad \boldsymbol{ED}_{C,t}\right] + u_{C,t}$$

where:

Use Per Customer ("$UPC_{C,t}$")	=	Billed Sales ("$Billed\ Sales_{C,t}$") divided by Customer Count ("$CC_{C,t}$"), in class "C", month "t"
Cycle Days ("$D_{C,t}$")	=	Average number of billed cycle days for billing month "t" in class "C"
Regression Coefficients ("$\boldsymbol{\beta_C}$")	=	Vector of UPC_C regression coefficients estimated using Conditional Least Squares/ARMA methods
Constant ("$\propto_C$")	=	Indicator variable for class constant (if applicable)
Degree Days ("$\boldsymbol{DD}_{C,t}$")	=	Vector of weather variables. Calculated value that drives monthly heating and/or cooling demand.

$$\boldsymbol{HDD}_{C,Base,t} = \sum_{d=1}^{Cycle_t} |max(0, Base\ Temp - Daily\ Avg\ Temp_d)| * BillingCycleWeight_{C,d,t}$$

$$\boldsymbol{CDD}_{C,Base,t} = \sum_{d=1}^{Cycle_t} |max(0, Daily\ Avg\ Temp_d - Base\ Temp)| * BillingCycleWeight_{C,d,t}$$

Date Indicator ("$\boldsymbol{D}_{M,t}$")	=	Vector of month/date specific indicator variables
Trend ("$T_{C,t}$")	=	Trend variable (not included in most classes)
Effective Retail Rates ("$\boldsymbol{RR}_{C,t}$")	=	The effective retail rate. The rate is smoothed, deflated by a Consumer Price Index, and interacted with macroeconomic variables and/or further transformed.
Economic and Demographic Variables ("$\boldsymbol{ED}_{C,t}$")	=	Vector of economic and/or demographic variables
Error term ("$u_{C,t}$")	=	ARMA error term

** The term vector or boldface type denotes one or more variables in the matrix.*

Peak Electric Hour and Natural Gas Day

The electric and natural gas peak demand models relate observed monthly peak system demand to monthly weather-normalized delivered demand. The models also control for other factors, such as observed temperature, exceptional weather events, day of week, or time of day.

The primary driver of a peak demand event is temperature. In winter, colder temperatures yield higher demand during peak hours, especially on evenings and weekdays. The peak demand model uses the difference of observed peak temperatures from normal monthly peak temperature and month specific variables, scaled by normalized average *monthly* delivered demand, to model the weather sensitive and non-weather sensitive components of monthly peak demand. In the long-term forecast, growth in monthly weather-normalized delivered demand will drive growth in forecasted peak demand, given the relationships established by the estimated regression coefficients.

The **electric peak hour** regression estimation equation is:

$$\max\left(Hour_{1,t} \ldots Hour_{H_t,t}\right) =$$
$$\boldsymbol{\beta}\left[\frac{Demand_{N,t}}{H_t}\boldsymbol{D}_{M,t} \quad \Delta Temperature_{N,t}\frac{Demand_{N,t}}{H_t}\boldsymbol{D}_{S,t}\boldsymbol{D}_{PeakType,t} \quad \boldsymbol{D}_{DoW,t} \quad D_{LtHr,t} \quad D_{Hol,t} \quad T_{Hot,t}\right] + \varepsilon_t$$

where:

Hourly Demand ("$Hour_{J,t}$")	=	Hourly PSE system demand (MWs) for hour j=1 to $H_{t,}$
Total Hours ("H_t")	=	Total number of hours in a month at time "t"
Regression Coefficients ("$\boldsymbol{\beta}$")	=	Vector of electric peak hour regression coefficients
Normalized Demand ("$Demand_{N,t}$")	=	Normalized total demand in month at time "t"
Temperature Deviation ("$\Delta Temperature_{N,t}$")	=	Deviation of actual peak hour temperature from *hourly* normal minimum peak temperature
Month Indicator ("$\boldsymbol{D}_{M,t}$")	=	Vector of monthly date indicator variables
Month Indicator ("$\boldsymbol{D}_{S,t}$")	=	Vector of seasonal date indicator variables
Peak Type ("$\boldsymbol{D}_{PeakType,t}$")	=	Vector of heating or cooling peak indicators
Day of Week Indicator ("$\boldsymbol{D}_{DoW,t}$")	=	Vector of Monday, Friday, and Mid-Week indicators
Evening Peak ("$D_{LtHr,t}$")	=	Indicator variable for evening winter peak
Winter Holiday ("$D_{Hol,t}$")	=	Indicator variable for holiday effects
Cooling Trend ("$T_{Hot,t}$")	=	Trend to account for summer air conditioning saturation
Error term ("ε_t")	=	Error term

Similar to the electric peaks, the gas peak day is assumed to be a function of weather and non-weather-sensitive delivered demand, the deviation of actual peak day average temperature from normal daily average temperature in a month, and type of days.

The **gas peak day** estimation equation is:

$$\max\left(Day_{1,t} \ldots Day_{Days_{t,t}}\right) = \boldsymbol{\beta}[BDemand_{N,t} \quad \Delta Temperature_{N,t} HDemand_{N,t} \quad \boldsymbol{D}_{M,t} \quad \boldsymbol{D}_{WE,t}] + \varepsilon_t$$

where:

Daily Demand ("$Day_{i,t}$") = Firm delivered dekatherms for day "i"

Total Days ("$Days_{t}$,") = Total number of days in a month at time "t"

Regression Coefficients ("$\boldsymbol{\beta}$") = Vector of gas peak day regression coefficients

Normalized Firm Heating Demand ("$HDemand_{N,t}$") = Normalized monthly firm delivered heating demand

Normalized Firm Base load Demand ("$BDemand_{N,t}$") = Normalized monthly firm delivered base load demand

Temperature Deviation ("Δ $Temperature_{N,t}$") = Deviation of observed daily average temperature from the normal minimum temperature for that month

Month Indicator ("$\boldsymbol{D}_{M,t}$") = Vector of monthly date indicator variables

Weekend Indicator ("$\boldsymbol{D}_{WE,t}$") = Vector of date specific indicator variables

Error term (or "ε_t") = Error term

The gas peak day equation uses monthly normalized firm delivered demand as an explanatory variable, and the estimated model weighs this variable heavily in terms of significance. Therefore, the peak day equation will follow a similar trend as that of the monthly firm demand forecast with minor deviations based on the impact of other explanatory variables. An advantage of this process is that it uses demand of distinct gas customer classes to help estimate gas peak demand.

Billed Sales Forecast

To forecast billed sales, PSE uses the UPC and customer count models derived above with external and internally derived forecast drivers. Economic, demographic and retail rate forecasts, as well as "normal" monthly degree days, are fitted with model estimates to create the 20-year use per customer and customer count projections by class. The class total billed sales forecasts are formed by multiplying forecasted use per customer and customers ($\widehat{UPC}_{C,t} * D_{C,t} * \widehat{CC}_{C,t}$), then adjusting for known future discrete additions and subtractions ("$Block\ Sales_{C,t}$").

Major block sales changes are incorporated as additions or departures to the sales forecast as they are not reflected in historical trends covered in the estimation sample period. Examples of such items include emerging electric vehicle (EV) demand, large greenfield developments, changes in usage patterns by large customers, fuel and schedule switching by large customers, or other infrastructure projects. Finally, for the IRP Base Demand Scenario, the forecast of billed sales is reduced by new programmatic conservation ("$Conservation_{C,t}$") by class, using established conservation targets in 2020-2021.

The total **billed sales forecast** equation by class and service is:

$$Billed\ Sales_{C,t} = \widehat{UPC}_{C,t} * D_{C,t} * \ \widehat{CC}_{C,t} + Block\ Sales_{C,t} - Conservation_{C,t}$$

Where:

Time ("t")	=	Forecast time horizon, $\{2018M1 \ldots .2039M12\}$
Use Per Customer ("$\widehat{UPC}_{C,t}$")	=	Forecast use per customer
Cycle Days ("$D_{C,t}$")	=	Average number of scheduled billed cycle days for billing month "t" in class "C"
Customer Count ("$\widehat{CC}_{C,t}$")	=	Forecast count of customers
Conservation ("$Conservation_{C,t}$")	=	Base Scenario: Ramped/shaped programmatic conservation targets
Major New Sales ("$Block\ Sales_{C,t}$")	=	Ramped/shaped expected entering or exiting sales not captured as part of the customer count or UPC forecast.

Total billed sales in a given month are calculated as the sum of the billed sales across all customer classes:

$$Total\ Billed\ Sales_t = \sum_c Billed\ Sales_{c,t}$$

Base Demand and Final Demand Net of DSR Forecasts

Demand

Total system demand is formed by distributing monthly billed sales into calendar sales, then adjusting for company own use and losses from distribution, and for electric only, transmission. The electric and gas demand forecasts ("$\widehat{Demand}_{N,t}$") form the 2021 IRP Electric and Natural Gas Base Demand Forecasts. For the IRP Final Demand scenario, the optimal conservation bundle is found in the 2021 IRP.

Peak Demand

PSE forecasts peak demand using the peak models estimated above, plus assumption of normal design temperatures, forecasted total system normal demand less conservation ("$\widehat{Demand}_t - Conservation_t$"), and short-term forecasted peak conservation targets. Peak conservation and demand conservation are distinct: they are related, however, different conservation measures may have larger or small impacts on peak when compared with energy. Thus, the peak models seek to reflect exact peak conservation assumption from programmatic activities and the previous Conservation Potential Assessment, as opposed to simple downstream calculations from demand reduction. These calculations yield system hourly peak demand each month based on normal design temperatures.

$$Peak\ Demand_t = F\left(\widehat{Demand}_{t,}, \Delta Temperature_{N,Design,t}\right) - Conservation_{Peak,t}$$

Where:

$Peak\ Demand_t$	=	Forecasted maximum system demand for month "t"
Time ("t")	=	Forecast time horizon, $\{2020M1 \ldots .2039M12\}$
Delivered Demand Forecast ("$\widehat{Demand}_t$")	=	Forecast of delivered demand for month "t"
Temperature Deviation ("$\Delta Temperature_{Normal,Design,t}$")	=	Deviation of peak hour/day design temperature from monthly normal peak temperature
Conservation ("$Conservation_{Peak,t}$")	=	Ramped/shaped peak conservation resulting from programmatic conservation targets; IRP Optimal DSR

For the electric peak forecast, the normal design peak hour temperature is based on the median ("1 in 2" or 50th percentile) of the last of seasonal minimum temperatures for years 1988 to 2017 during peak hours (HE8 to HE20) observed at Sea-Tac (KSEA), as reported by NOAA. For winters spanning 1988 to 2017, the median observed peak temperature is 23 degrees Fahrenheit. The annual winter peak forecast is set at the maximum normal peak observed in a year, which is currently a December weekday evening.

For the gas peak day forecast, the design peak day is a 52 heating degree day (13 degrees Fahrenheit average temperature for the day). This standard was adopted in 2005 after a detailed cost-benefit analysis requested by the WUTC. The analysis considered both the value customers place on reliability of service and the incremental costs of the resources necessary to provide that reliability at various temperatures. We use projected delivered demand by class with this design temperature to estimate gas peak day demand. PSE's gas planning standard covers 98 percent of historical peak events, and it is unique to our customer base, our service territory and the chosen form of energy.

For the 2021 IRP Base Peak Demand Scenario, the effects of the 2020 and 2021 DSR targets are netted from the peak demand forecast to account for programmatic conservation already underway. This enables the choice of optimal resources and conservation to meet peak demand. Once the optimal DSR is derived from the IRP, the peak demand forecast is further adjusted for the peak contribution of future conservation.

2. STOCHASTIC DEMAND FORECASTS

Demand forecasts are inherently uncertain, and to acknowledge this uncertainty, the IRP considers stochastic forecast scenarios. Examples of drivers of forecast uncertainty include future temperatures, customer growth, usage levels and electric vehicle growth. To model these uncertainties, multiple types of stochastic forecast scenarios are created for different IRP Analyses. These demand and peak forecast permutations include:

- Monthly demand and peak forecasts
  - 250 gas and 310 electric stochastic monthly demand and peak forecasts
  - high/low forecast monthly demand and peak forecasts
- Hourly demand forecasts
  - A typical hourly load shape
  - 88 stochastic hourly forecasts for years 2027-2028 and 2031-2032.

Monthly Demand and Peak Demand

To create the set of stochastic electric and gas demand forecasts, the demand forecasts assume economic/demographic, temperature, electric vehicle and model uncertainties. The high and low demand forecasts are derived from the distribution of these stochastic forecasts at the monthly and annual levels.

Economic and Demographic Assumptions

The econometric demand forecast equations depend on certain types of economic and demographic variables; these may vary depending on whether the equation is for customer counts or use per customer, and whether the equation is for a residential or non-residential customer class. In PSE’s demand forecast models, the key service area economic and demographic inputs are population, employment, unemployment rate, personal income, manufacturing employment and US gross domestic product (GDP). These variables are inputs into one or more demand forecast equations.

To develop the stochastic simulations of demand, a stochastic simulation of PSE’s economic and demographic model was performed to produce the distribution of PSE’s economic and demographic forecast variables. Since these variables are a function of key U.S. macroeconomic variables such as population, employment, unemployment rate, personal income, personal consumption expenditure index and long-term mortgage rates, we utilized the stochastic simulation functions in EViews[1] by providing the standard errors for the quarterly growth of key

1 / *EViews is a popular econometric forecasting and simulation tool.*

U.S. macroeconomic inputs into PSE's economic and demographic models. These standard errors were based on historical actuals from the last 30 years, ending 2019. This created 1,000 stochastic simulation draws of PSE's economic and demographic models, which provided the basis for developing the distribution of the relevant economic and demographic inputs for the demand forecast models over the forecast period. Outliers were removed from the 1,000 economic and demographic draws. Then 250 draws were run through the electric and natura; gas demand forecasts to create the 250 stochastic simulations of PSE's demand forecasts.

Temperature

Uncertainty in the levels of heating and cooling load is modeled by considering varying historical years' degree days and temperatures. Randomly assigned annual "normal" weather scenarios are sourced from actual observations of degree days for electric and natural gas demand and seasonal minimum/maximum on-peak hourly temperatures for electric peak. The years considered for stochastic energy demand and peak range between 1990 and 2019.

Electric Vehicles

PSE's high and low EV energy consumption scenarios are based on PSE's base case EV forecast. The high and low scenarios were developed by calibrating data from the Pacific Northwest National Laboratory's "Electric Vehicles at Scale – Phase I; Analysis: High EV Adoption Impacts on the Western U.S. Power Grid" (July 2020) to PSE's EV forecast. To determine EV energy consumption and peak loads, the ratios of kWh/vehicle and kW/vehicle for residential charging and commercial charging were calculated based on PSE's load forecast data in the year 2028. The ratios were applied to the high and low scenarios of incremental EVs in the PSE balancing area.

Model Uncertainty

The stochastic demand forecasts consider model uncertainty by adjusting customer growth and usage by normal random errors, consistent with the statistical properties of each class/sub-class regression model. Model adjustments such as these are consistent with Monte-Carlo methods of assessing uncertainty in regression models.

The high and low demand forecasts are defined in the IRP as the monthly 90th and 10th percentile, respectively, of the 250 stochastic simulations of demand based on uncertainties in the economic and demographic inputs and the weather inputs.

Hourly Demand

Resource Adequacy Modelling

For the resource adequacy model, 88 stochastic hourly forecasts for year 2027-2028 and 2031-2032 were developed. For the period April 1, 2013 to December 31, 2019, PSE used the statistical hourly regression equation to estimate hourly demand relationships:

$$Demand_{h,d,s,t} = \boldsymbol{\zeta_h}\left[(1 - D_{h=1})Demand_{h-1,d,t} \quad \boldsymbol{D_{M,t}} \quad D_{Hol,d,t} \quad \boldsymbol{D}_{DoW,d,t} \quad \boldsymbol{T}_{h,d,t}\right] + u_{i,d,t}$$

where:

$$\boldsymbol{T}_{h,d,t} = \left[\max\left(55 - T_{h,d,t}, 0\right) \quad \max\left(T_{h,d,t} - 55{,}0\right) \quad \max\left(55 - T_{h,d,t}, 0\right)^2 \quad D_{h=1}\max(40 - DAvg_{t-1}, 0) \quad D_{h=1}\max(DAvg_{t-1} - 70{,}0)\right]$$

Hourly Demand (“$Demand_{h,d,t}$”)	=	PSE hourly demand
Hour “h”	=	Hour of day {1…24}
Day “d”	=	Day grouping {Weekday, Weekend/Holiday}
Date “t”	=	Date
Daily temperature shape “s”	=	Indicator of daily average temperature type
Regression Coefficients (“$\boldsymbol{\zeta_h}$”)	=	Vector regression coefficients
Hourly Temperature (“$T_{h,d,t}$”)	=	Hourly temperature at Sea-Tac (“KSEA”)
Lag Daily Average Temp (“$DAvg_{t-1}$”)	=	Previous daily average temperature
Monthly Indicator (“$\boldsymbol{D}_{M,t}$”)	=	Vector of monthly date indicator variables
Day of Week Indicator (“$\boldsymbol{D}_{DoW,d,t}$”)	=	Vector day indicators {Monday, Friday, Sunday}
Holiday Indicator (“$D_{Hol,d,t}$”)	=	Holiday indicator
Hour Ending 1 Indicator (“$D_{h=1}$”)	=	Indicator Variable for hour ending 1
Error term (or “$u_{i,d,t}$”)	=	ARMA(1,1) error term

Demand is estimated for each hour, day of week type and daily average temperature type, yielding 24x2x4 sets of regression coefficients. An annual hourly demand profile is forecasted by fitting an annual 8,760-hour temperature profile and calendar. After creating this fitted value, the forecast is further calibrated by additional hourly demand from an annual EV profile, an AC saturation adjustment for future peak hours with temperatures greater than 72 degrees, the monthly delivered demand ("$\widehat{Demand}_{N,t}$") forecasted for the 2021 Base Demand Forecast, and various stochastic temperature and demand scenarios.

Aurora Modeling Process

An hourly profile of PSE electric demand was produced to support the IRP portfolio analyses. We use our hourly (8,760 hours + 10 days) profile of electric demand for the IRP as an input into the AURORA portfolio analysis. One full year of hourly data is created and then the monthly demand forecast is shaped to the hourly data when running the portfolio analysis. Day one of the hourly shape is a Monday, day two is a Tuesday and so on, so the AURORA model adjusts the first day to line up January 1 with the correct day of the week. The estimated hourly distribution is built using statistical models relating actual observed temperatures, recent demand data and the latest customer counts.

2021 PSE Integrated Resource Plan

G

Electric Analysis Models

To be provided in the final IRP.

2021 PSE Integrated Resource Plan

H

Electric Analysis Inputs and Results

To be provided in the final IRP.

I Natural Gas Analysis Results

To be provided in the final IRP.

J Regional Transmission Resources

This appendix describes the Pacific Northwest transmission system and the constraints that currently impact PSE; the opportunities for expanding transmission capabilities; how transmission is modeled in this IRP; and regional efforts to coordinate transmission planning and investment.

Contents

1. OVERVIEW

PSE buys and sells wholesale power and transmission with counterparties in the Pacific Northwest, California and Canada. To deliver remote, off-system power to our customers, PSE relies on the Pacific Northwest regional transmission system; however, that system is already constrained, especially the regional systems that serve the Puget Sound area.

These constraints present a growing challenge for PSE, because PSE moves significant amounts of energy and capacity into the Puget Sound area from resources in eastern Washington (east of the Cascades), the Mid-C trading hub, eastern Montana, and from resources along the I-5 corridor. The IRP portfolio modeling results confirm that PSE's capacity and resource needs due to CETA will dramatically increase PSE's need to cost effectively deliver off-system renewable resources to our service territory, and this rapid growth in renewable resources in locations outside the PSE service territory will put increased demand on transmission providers in the region.

PSE will work to optimize use of its existing transmission portfolio to meet our growing need for renewable resources in the near term, but in the long term, meeting CETA requirements will mean that the Pacific Northwest transmission system will need significant expansion and upgrades to keep pace. The main areas of high-potential renewable development are east of the Cascades (Washington and Oregon), in the Rocky Mountains (Montana, Wyoming), in the desert southwest (Nevada, Arizona) and in California.

This appendix describes the Pacific Northwest transmission system and the constraints that currently impact PSE; the opportunities for expanding transmission capabilities; how transmission is modeled in this IRP; and regional efforts to coordinate transmission planning and investment.

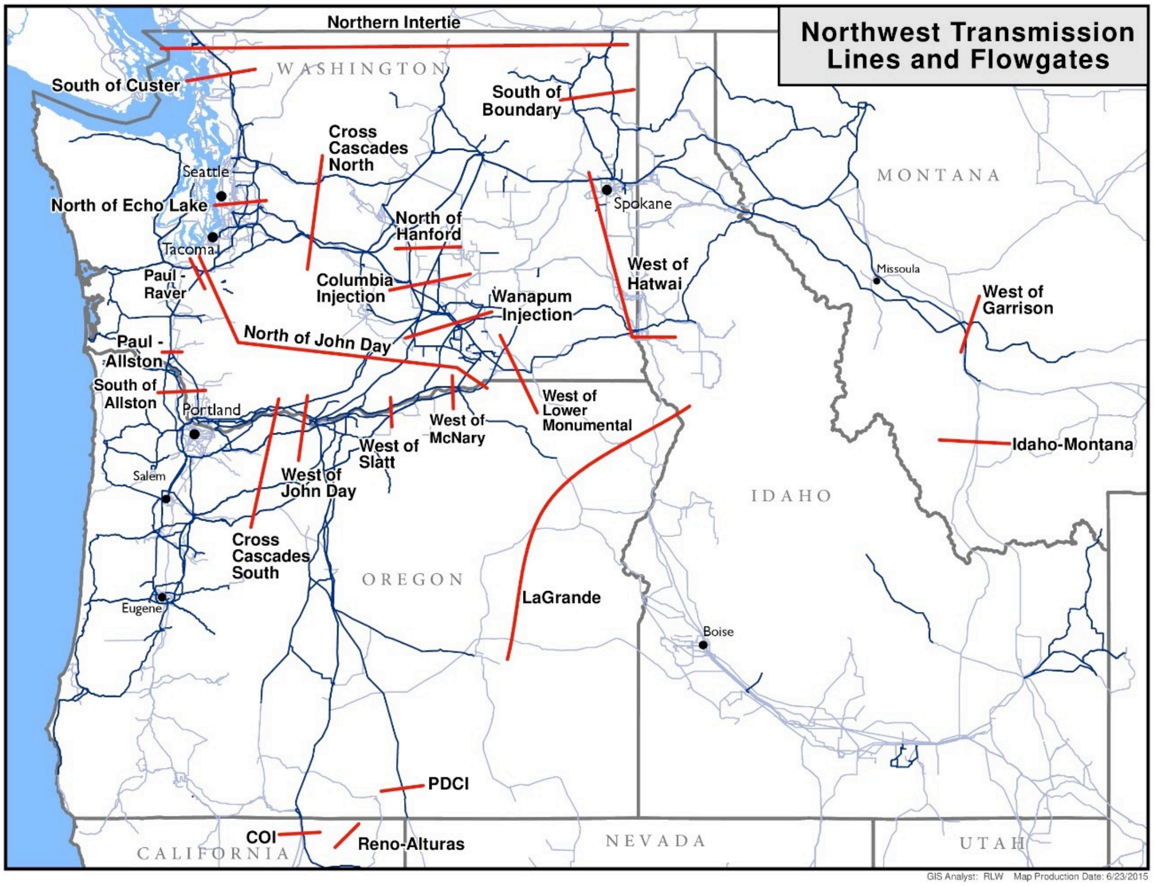
2. THE PACIFIC NORTHWEST TRANSMISSION SYSTEM

The power that PSE delivers to customers from remote, off-system resources travels through the Pacific Northwest transmission system in order to reach the Puget Sound area. The Bonneville Power Administration (BPA) owns and operates approximately 75 percent of the high-voltage transmission grid across eight states in the region. PSE is heavily reliant on BPA; currently, PSE has over 5,000 MW of long-term firm transmission under contract with BPA. This reliance is an ongoing risk to PSE's power costs due to escalating BPA rate pressure. For example, BPA's current BP-22 rate case proposes a 30 percent increase in transmission rates from 2021-2025.

Power travels to PSE's service area through different paths and flowgates[1] on the BPA system from off-system resources. These flowgates are shown in Figure J-1. Due to load growth and/or additional renewable generation, many paths in the Pacific Northwest are already constrained, with little or no available transmission capacity (ATC) available for purchase by regional transmission customers. As a result, the region experiences transmission constraints during various times of the year, sometimes resulting in curtailments of firm contractual transmission rights.

1 / A flowgate is defined as a transmission line or other equipment that is monitored for overloads incurred by normal operation conditions, such as congestion, and for the loss of another transmission line or equipment.

Figure J -1: Graphical Representation of BPA Transmission System Flowgates



The PSE Transmission Portfolio

PSE Merchant (PSEM) is responsible for obtaining the transmission service needed to serve PSE load and for scheduling the use of that transmission in an optimal manner to cost effectively meet customer demand. The transmission portfolio is managed to ensure firm delivery of off-system resources, participate in regional energy markets, optimize the energy portfolio, and ensure adequate delivery of energy during winter peak loads.

Figure J-2 summarizes PSE's BPA-contracted transmission. The transmission rights were divided into five resource group regions based on their geographic relationship to generic resources modeled in this IRP. See Chapter 5, Key Assumptions, for a description of the transmission constraints analysis.

Figure J-2: Summary of BPA-contracted Transmission by Resource and Location

Resource/Location	Resource Group Region (See Chapter 5)	Current Contracted BPA Transmission (MW)	Note
Mid-C	Central WA	2,050 MW	1,500 MW available for market purchases, remainder for hydro contracts
Lower Snake River	Eastern WA	500 MW	350 MW in use, 150 MW available in 2024
Hopkins Ridge	Eastern WA	150 MW	Not included in transmission constraint model in Chapter 5
Goldendale	Southern WA/ Gorge	330 MW	
Mint Farm	Western WA	335 MW	
TransAlta/Centralia	Western WA	100 MW	Used for Centralia PPA ending in 2026
Colstrip	Montana	750 MW	
PG&E Exchange	Western WA	600 MW	300 MW bidirectional, not included in transmission constraint model in Chapter 5

PSEM's transmission portfolio consists of transmission rights on PSE's system and BPA transmission for off-system resources. PSEM holds BPA transmission rights from the Mid-C trading hub for meeting winter peak demands and for trading to economically optimize the power portfolio. In addition, PSEM has transmission rights on the Southern Intertie, California/Oregon Intertie (COI), Montana Intertie, and the Colstrip Transmission System. The Southern Intertie and COI transmission rights are used for a seasonal exchange with PG&E. PSEM also uses contracted BPA transmission rights to access the Western Energy Imbalance Market (EIM) through transmission paths with PacifiCorp, Portland General and Idaho Power.

Figure J-3: BPA Managed Flowgates and PSE Off-System Resources

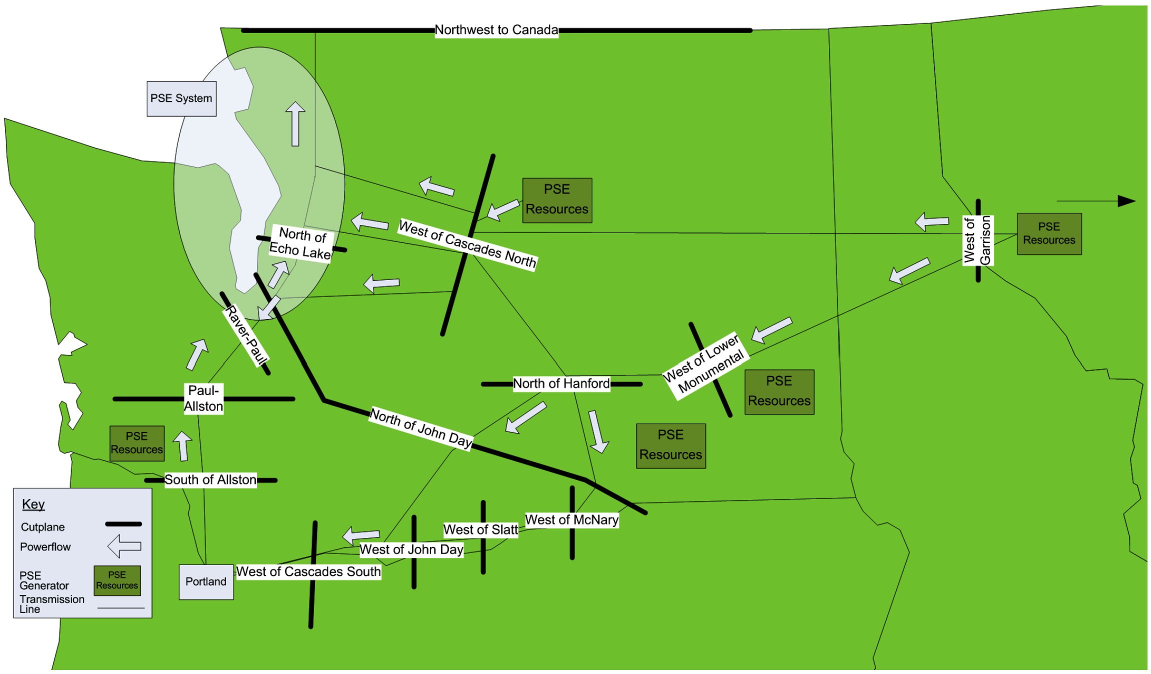


Figure J-3 is an overview of PSEM's off-system resources overlaid with the BPA-managed flowgates. Below is a summary of the most significant flowgates and paths affecting delivery of energy from remote resources to PSE's service area.

a. The majority of energy from PSE's eastern Washington resources flows across the constrained West of Cascades North flowgate and into the Puget Sound area. This flowgate is most constrained during heavy winter loading periods.
b. A portion of the energy flowing from eastern Washington resources also flows over the West of Cascades South flowgate, and as it travels to loads in the Puget Sound area, it flows over the North of John Day and Raver – Paul flowgates. The West of Cascades South flowgate is most constrained during heavy winter loading periods, while the North of John Day and Raver – Paul flowgates are typically most constrained during heavy summer loading periods.
c. Energy from PSE resources in Montana flow over the West of Garrison flowgate.
d. Congestion issues in the Puget Sound area are monitored by the North of Echo Lake flowgate and the Northern Intertie. Generation from PSE resources located in Skagit and Whatcom Counties is particularly important in reducing curtailment risk on this flowgate.
e. Energy from PSE's Lower Snake River Wind Project flows across the West of Lower Monumental flowgate.

Some paths, like West of Garrison, are designed to operate close to their limits, others are not; the latter group presents areas of the system where PSE sees a particular importance in continuing to study, develop and possibly construct new transmission.

Figure J-4 lists the amount of total transmission capability and available transmission capability on BPA flowgates that affect delivery of off-system resources to PSE. This table highlights a constrained regional transmission, especially on transmission lines that would deliver energy from outside the Puget Sound area.

Figure J-4: BPA Flowgates Affecting Delivery of Off-system Resources to PSE's System Total Transmission Capability and Long-term Firm Available Transmission Capability

To come in IRP final draft.

3. OPPORTUNITIES FOR EXPANDING REGIONAL TRANSMISSION CAPABILITY

BPA TSR Study and Expansion Process (TSEP)

BPA performs annual TSEP (formerly known as Network Open Season [NOS]) studies that combine various Transmission Service Requests (TSRs) from transmission customers into a single study. The TSEP process was designed to obtain financial commitments from transmission customers in advance of any new facility construction. For long-term transmission requests, the process analyzes impacts and new transmission facility requirements on an aggregated basis. Customers that submit a TSR in OASIS (Open Access Same-time Information System) by the study deadline can elect to be included in the annual TSEP cluster study.

A TSR submitted to BPA by PSE could result in TSEP study results with costly upgrades and completion dates of 10 years or longer. For example, the cost of Montana-to-Washington upgrade projects identified in the 2020 TSEP study (in response to requests from other customers) is currently estimated at $1.4 billion, and the earliest completion date is 2030. PSE is likely to see more high-cost and long lead-time proposals in the constrained areas of BPA's system, especially in cross Cascades transmission areas. There is no commitment risk for PSE to submit TSRs in constrained areas of BPA's system since contracts are not awarded until construction is under way, but we would want such a strategy to align with areas that have high potential for renewables development.

2019 TSEP Study

PSE participated in the 2019 TSEP study. The table below lists the outcomes of the study for PSE TSRs. PSE was awarded transmission for the Goldendale Generation Plant but the Hopkins Ridge TSR resulted in a need to either resolve location transmission constraints or an upgrade called the Walla Walla Project.

Figure J-5: Summary of 2019 TSEP Study Results for PSE TSRs[2]

Project	Start Date	End Date	MW	Status
Hopkins Ridge (Central Ferry substation)	3/1/2024	1/1/2027	75	Walla Walla Project or resolution of local transmission constraints
Goldendale (2 TSRs)	11/1/2021	3/1/2024	27	Awarded

2020 TSEP Study

In May 2020, BPA published the results of the 2020 TSEP Cluster Study. The cluster study was comprised of 62 TSRs totaling 3,871 MW of incremental transmission service. PSE did not submit any TSRs that took part in the study. A total of 17 TSRs submitted by four BPA transmission customers listed PSE as a Point of Delivery (POD). The results of those 17 TSRs are listed in Figure J-6 along with the required upgrade projects. These results are indicative of the cost and timing of future upgrades for future TSRs of BPA transmission to PSE.

Figure J-6: Summary of 2020 TSEP Study Results for Third Parties with PSE PODs

PSE POD	First Start Date	Last End Date	Total MW Requested	Upgrade Required (Cost $M)	Energization Date
COVNGTN230PSEI	12/1/21	1/1/31	970	Schultz-Raver Project ($42.6)	Fall 2025
PSEI_CENTCNTGS	12/1/21	11/1/24	7	Schultz-Raver Project ($42.6) PSAST Projects	Fall 2025
PSEI_STHCNTGS	12/1/23	12/1/28	200	Schultz-Raver Project ($42.6) Schultz-Wautoma ($0) Covington-Chehalis ($12.6)	Fall 2025 Spring 2022 Fall 2024

2 / Refer to BPA's TSEP Page: https://www.bpa.gov/transmission/CustomerInvolvement/TSRStudyExpansionProcess/Pages/default.aspx

Future TSEP Studies

BPA announced that it will perform another TSEP in 2021 to identify transmission projects required to grant new transmission service requests as part of its ongoing efforts to address constraints. The 2021 study will take into account the 2016, 2019 and 2020 TSEP cluster study results and prior NOS study results.

Montana Transmission

Wind resources in Montana are attractive because of their higher capacity factors and diverse seasonal output compared to the Washington wind currently in PSE's energy portfolio. The retirement of Colstrip Units 1 and 2 provided for an opportunity to evaluate Montana wind resources in PSE's 2018 RFP, allowing for the potential repurposing of Colstrip transmission to PSE's service territory. The impact of such repurposing on the available transfer capacity for PSE's portion of the Colstrip Transmission System is being studied by NorthWestern Energy, as well as by affected systems such as BPA.

Idaho and Wyoming

PSE is evaluating the potential investment in transmission service on the Boardman to Hemingway (B2H) and Gateway West projects. These investments would provide access to Idaho and Wyoming renewable resources. Wyoming wind is particularly attractive because of its capacity factors and diverse wind profiles and is being evaluated as a potential resource in this IRP. In order to deliver resources from B2H to PSE load, PSE will also need to acquire BPA transmission from the Boardman location (newly proposed Longhorn substation) to PSE's system. BPA will perform a study in 2021 to determine availability of that transmission service by 2026. We expect the results of that study later in 2021.

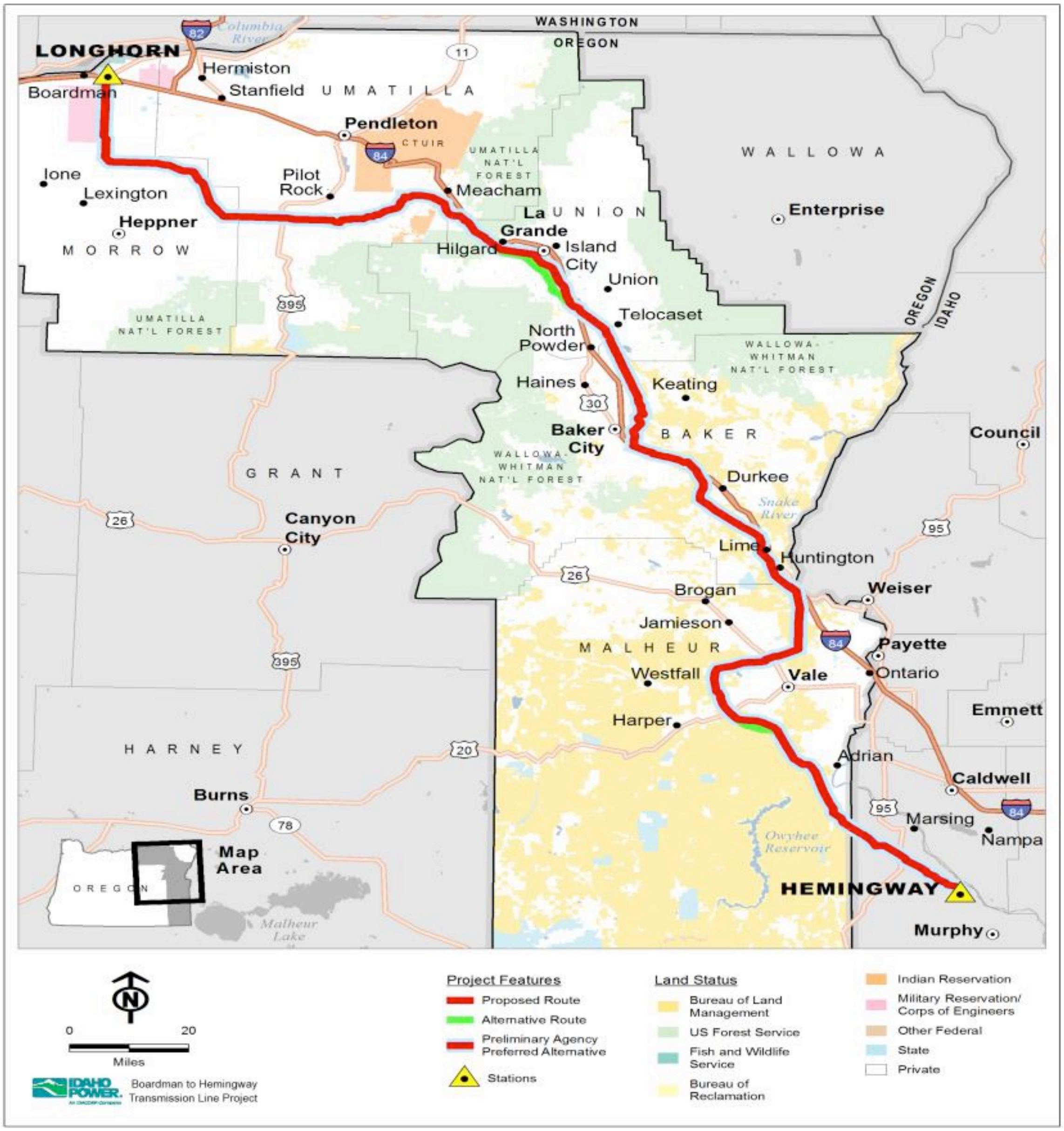
PSE is conducting a due diligence assessment of B2H and Gateway West that includes an evaluation of project permitting, construction schedules, construction cost estimates and project risks. This assessment is planned to be completed during 2021 and will inform PSE's future decision. The following is a high-level summary of the B2H and Gateway West transmission projects.

Boardman to Hemingway (B2H)

PSE is evaluating an investment in 400 MW of currently available east to west capacity on the B2H project, with a potential for another 200 MW for a total of 600 MW of transmission. An investment in B2H, along with potential investments in one or more segments of Gateway West, would provide PSE access to high-value wind and solar resources in southern Idaho, western Wyoming and eastern Wyoming (see Figure J-7).

The B2H project is a proposed 500 kilovolt transmission line that will run approximately 290 miles across eastern Oregon and southwestern Idaho. It will connect the proposed Longhorn Substation four miles east of Boardman, Oregon, to Idaho Power's existing Hemingway Substation in Idaho. Idaho Power is partnering with PacifiCorp to fund and construct B2H and to obtain necessary permits for a planned 2026 or later in-service date. Construction is expected to take three to four years to complete.

Figure J-7: B2H Route Map



Gateway West

In addition to B2H, PSE is evaluating transmission investments in one or more segments of Gateway West, starting at the eastern Wyoming substation Aeolus (see Figure J-8) and terminating at the Hemingway substation in southern Idaho. PacifiCorp is the primary transmission provider for Gateway West and is partnering with Idaho Power on portions of the southern Idaho segment. The three segments of Gateway West that PSE is evaluating are discussed below.

HEMINGWAY TO POPULUS. This western segment is located in southern Idaho. Along with B2H, it would provide PSE access to southern Idaho renewable resources including wind and solar projects. The planned construction date generally aligns with the B2H project schedule, but there is not yet a firm construction date.

POPULUS TO BRIDGER/ANTICLINE. This segment is located in southern Idaho and western Wyoming. Along with Hemingway to Populus, it would provide PSE access to western Wyoming wind and solar resources. Similar to the Hemingway to Populus segment, the planned construction date generally aligns with the B2H schedule.

BRIDGER/ANTICLINE TO AEOLUS. PacifiCorp completed construction of this line in 2020. The line runs from western Wyoming to eastern Wyoming, and it would provide PSE access to high-capacity wind resources in eastern Wyoming.

Figure J-8: Gateway West Route Map

4. FUTURE REGIONAL TRANSMISSION STRATEGIES

Transmission Strategies

Four strategies could be implemented to ensure sufficient transmission for the delivery of off-system renewable projects to PSE's system.

- **Strategy 1**. Repurpose the existing BPA transmission portfolio. Use Mid-C transmission for renewables, Montana transmission for wind resources, and co-locate new renewable resources at existing PSE generating facilities.
- **Strategy 2**. Connect resources directly to PSE system or acquire off-system renewables through a PSE transmission intertie.
- **Strategy 3**. Contract with BPA for additional transmission either directly or through third parties (developers, resellers).
- **Strategy 4**. Build new transmission.

Strategy 1

PSEM has approximately 1,500 MW of transmission at Mid-C which is currently used for market purchases. Some portion of Mid-C transmission could be used to take delivery of new renewable projects that interconnect at Mid-C or that deliver to Mid-C. The capacity credit for the transmission could be retained by having access to purchasing energy at the Mid-C market hub during winter peak events.

PSE has future transmission opportunities at several existing off-system generating facilities. A portion of PSE's Colstrip transmission could be repurposed for delivery of Montana wind as the coal units retire. At the Lower Snake River wind plant, PSE has additional BPA interconnection and transmission rights to build new wind capacity. Renewable resources could also be co-located at the Goldendale and Mint Farm generating stations to share the BPA transmission rights from those locations.

Strategy 2

PSE has some available transmission on the main network and interties for delivery of energy from utility-scale projects or for contract with a third party for renewable PPAs.

Strategy 3

PSE could contract with BPA for additional transmission rights at candidate project locations for future resources by submitting TSRs (transmission service requests) and participating in BPA's annual cluster study. Additional BPA contracted transmission could also be secured through third parties such as renewable project developers and resellers of transmission. Due to current and anticipated regional transmission constraints, newly contracted BPA transmission service will likely require costly major upgrades and longer time lines to complete construction projects before new transmission service could commence.

Strategy 4

New regional transmission capacity will likely need to be constructed to meet the CETA requirements by 2045. As noted above, PSE is considering the Boardman to Hemmingway and Gateway West transmission projects to access renewable resources in Idaho and/or Wyoming. In addition to those projects, PSE will assess existing rights of way for opportunities to access renewable energy zones in Washington state. PSE will also need to evaluate future greenfield transmission development with possible partners in the region. This will be an ongoing effort over the next several years since greenfield transmission projects can take 15 to 20 years to permit and put into service.

Future Transmission Considerations

Historically, PSE has required that any new resources secure long-term firm (LTF) transmission up to the nameplate rating of the generation. This policy was implemented to reduce the risk of being unable to deliver energy or produce RECs due to insufficient transmission. PSE is now considering acquisition of less than nameplate capacity of LTF transmission for renewable resources because the intermittent output of renewable resources usually leaves transmission idle, and there is often short-term transmission available (firm and non-firm) to purchase or redirect. This new policy could lower the future transmission need for renewable resources required to meet CETA and better optimize PSE's transmission portfolio. This IRP includes a sensitivity analysis testing the impact on portfolio cost when firm transmission is under-built for renewable resources. That analysis is described in Chapter 5, Key Assumptions, and results are included in Chapter 8, Electric Analysis.

In May 2020, BPA began offering a new transmission product called long-term Conditional Firm Service (CFS). This is a form of long-term firm point-to-point (LTF PTP) transmission service with either a limit on the number of hours per year that it can be curtailed or based upon system conditions. The CFS inventory is posted, and it presents another limitation with respect to some of the previously identified flowgates. The NOEL and West of Hatwai flowgates are showing zero Conditional Firm Inventory (CFI), but there is CFI along the Cross Cascades North flowgate. This flowgate is fully subscribed for the winter months of the year but typically has ATC during the remaining months. This product still has some uncertainty about how effective it will be with new renewable projects; PSE will evaluate CFS on a case-by-case basis when it is available from BPA. The cost for CFS is the same as LTF PTP.

In 2019, CAISO began to study the benefits of an Extended Day Ahead Market (EDAM) that would be available to EIM participants and could be implemented as soon as 2022. This new market would allow EIM entities to participate in the current CAISO day ahead market. Initial studies have shown additional benefits of integrating a day ahead market construct on top of the EIM. Like the EIM, EDAM is being considered as a voluntary construct. In order to participate in EDAM, a utility would need to be a member of EIM. PSE is a member of the EIM and will continue to participate in the development of EDAM with other EIM entities and CAISO. One transmission-related aspect of the EDAM is to optimize transmission rights from participants and to make available unused/unsold transmission from Transmission Providers. As a result, the EDAM could help to optimize regional transmission and inform PSEM's future strategies on transmission acquisition.

5. REGIONAL TRANSMISSION PLANNING EFFORTS

PSE became a member of the newly formed NorthernGrid in 2020. As a Regional Planning Organization (RPO), NorthernGrid was formed as an association for the purpose of coordinating regional transmission planning for NorthernGrid members and facilitating compliance with certain FERC requirements relating to transmission planning (including Order Nos. 890 and 1000) for those members who are required (or may elect) to comply with such requirements. It is a successor organization to ColumbiaGrid, which formerly provided the same RPO services as NorthernGrid for PSE and other regional entities. NorthernGrid combines entities from ColumbiaGrid and the Northern Tier Transmission Group (NTTG).

FERC Orders 890 and 1000

PSE has long recognized the need for open, transparent and coordinated transmission planning and has consistently been ahead of regulation in its regional planning practices. The Federal Energy Regulatory Commission (FERC) has issued a series of orders, although two are regarded as seminal. These are Orders 890 and 1000, which have important and universal application to regulated Transmission Providers.

In the late 2000s, FERC recognized that "undue discrimination existed under the pro forma Open Access Transmission Tariff (OATT)."[3] The OATT had been in place since 1996, when it was mandated by FERC in Order 888.[4]

FERC Order 890, issued in February 2007, has three main goals: 1) strengthen the OATT to ensure that it achieves its original purposes of remedying undue discrimination; 2) provide greater specificity to reduce opportunities for undue discrimination and facilitate the Commission's enforcement; and 3) increase transparency in the rules applicable to planning and use of the transmission system.[5] FERC highlighted the six most critical types of reforms made in Order 890:

1. Increase nondiscriminatory access to the grid by eliminating the wide discretion that transmission providers currently have in calculating available transfer capability (ATC).[6]

3 / FERC Order 890 ¶1
4 / Ibid
5 / Ibid
6 / Ibid at ¶2

2. Increase the ability of customers to access new generating resources and promote efficient utilization of transmission by requiring an open, transparent and coordinated transmission planning process.[7]
3. Increase the efficient utilization of transmission by eliminating artificial barriers to use of the grid.[8]
4. Facilitate the use of clean energy resources such as wind power.[9]
5. Strengthen compliance and enforcement efforts.[10]
6. Modify and improve several provisions of the OATT … and clarify others that have proven ambiguous.[11]

The requirements of Order 890 are far-reaching and mandate changes and more open reporting in PSE's local and regional transmission planning, including the development of Attachment K with stakeholder participation.[12]

Issued in July 2011, FERC Order 1000 built upon the openness and transparency requirements of FERC Order 890 by requiring greater regional participation. Order 1000 includes provisions requiring transmission providers to:

- participate in a regional transmission planning process that evaluates transmission alternatives at the regional level that may resolve the transmission region's needs more efficiently and cost-effectively than alternatives identified by individual public utility transmission providers in their local transmission planning processes;[13]
- have in place a method, or set of methods, for allocating the costs of new transmission facilities selected in a regional transmission plan for purposes of cost allocation;[14] and
- amend their OATTs to describe procedures that provide for the consideration of transmission needs driven by Public Policy Requirements in the local and regional transmission planning processes.[15,16]

The requirements of FERC Order 1000 are designed to improve coordination across the regional planning processes by developing and implementing procedures for joint evaluation and the sharing of information between transmission providers and balancing authority areas. All regulated utilities are required to participate in a regional planning organization.

7 / Ibid at ¶3.
8 / Ibid at ¶4
9 / Ibid.at ¶5
10 / Ibid.at ¶6
11 / Ibid at ¶7.
12 / Ibid at ¶437.
13 / FERC Order 1000 ¶6
14 / Ibid at ¶9
15 / Ibid at ¶203
16 / Public Policy Requirements are defined as transmission needs driven by public policy requirements established by state or federal laws or regulations. (FERC Order 1000 ¶2)

ColumbiaGrid and NorthernGrid

In 2006, before FERC had issued its mandates in Orders 890 and 1000, PSE became a founding member of ColumbiaGrid, a non-profit membership corporation and regional planning organization. ColumbiaGrid's goals were to improve the operational efficiency, reliability and planned expansion of the Pacific Northwest transmission grid. ColumbiaGrid provided a number of services, including annual transmission system assessments, producing a regional biennial transmission plan and identifying transmission needs. ColumbiaGrid also facilitated a coordinated planning process for the development of multi-party transmission system projects. Members included PSE, Avista, BPA, Chelan County Public Utilities District (PUD), Grant County PUD, Seattle City Light, Snohomish PUD and Tacoma Power.

Efforts started several years ago to form a single, larger regional planning organization in the Pacific Northwest that combined ColumbiaGrid members with members of NTTG. NTTG was a group of transmission providers and customers who were actively involved in the sale and purchase of transmission capacity that delivered electricity to customers in the Northwest and Mountain states. The new entity was named NorthernGrid, combining the names of the two groups. NTTG members joining NorthernGrid included Idaho Power, MATL, NorthWestern Energy, Portland General Electric and PacifiCorp.

On August 20, 2019, PSE and six other FERC-regulated utilities[17] filed the Funding Agreement and individual concurrences forming NorthernGrid in FERC docket ER19-2650-000. The NorthernGrid Funding Agreement also includes non-jurisdictional utilities, including BPA.[18] As explained in the opening of this section, NorthernGrid is an unincorporated association formed for the purpose of coordinating regional transmission planning for NorthernGrid members and facilitating compliance with certain FERC requirements relating to transmission planning (including Order Nos. 890 and 1000) for those members who are required (or may elect) to comply with such requirements.[19] In the Funding Agreement, member utilities requested an effective date of October 31, 2019, continuing until December 31, 2021, when the agreement will need to be renewed. FERC approved the Funding Agreement in a Delegated Order on October 28, 2019.

PSE, along with other regulated NorthernGrid entities, submitted its revised Attachment K under NorthernGrid to FERC on September 6, 2019, with a requested effective date of January 1, 2020 in FERC docket ER19-2760-000. On December 27, 2019 FERC issued an Order rejecting the proposed Attachment K tariff changes relating to Regional Planning, Cost Allocation and

17 / NorthWestern Energy, Avista, Idaho Power, MATL (Montana-Alberta Tie-Line), PacifiCorp, Portland General Electric
18 / Non-Jurisdictional entities, such as BPA, participate by choice in these regional planning organizations.
19 / NorthernGrid Funding Letter, Recital Number One.

Transmission needs driven by Public Policy Requirements. FERC did not find issue with PSE's revised Local Plan in Attachment K. PSE, and the other regulated NorthernGrid entities, submitted an updated Attachment K filing on January 29, 2020 in FERC docket ER20-882-000 requesting an Effective Date of April 1, 2020. FERC approved the revised Attachment K tariff filing on March 31, 2020, approving the April 1, 2020 effective date.

For the 2020 calendar year, PSE retained its Attachment K through ColumbiaGrid until April 1, 2020 and switched its planning tariff to the NorthernGrid Attachment K on April 1, 2020. ColumbiaGrid unwound its corporate status and dissolved prior to the end of 2020.

Participation in a regional planning organization like ColumbiaGrid or NorthernGrid, while mandated by FERC, also gives utilities an opportunity to develop a coordinated regional plan and allocate costs for transmission improvement projects that cross over more than one utility. The coordinated efforts can provide solutions on a larger scale than local planning efforts if more than one member is experiencing the same constraint issue. It also provides outside stakeholders another opportunity to share project suggestions and designs for consideration in regional planning. Given PSE's location in western Washington and the number of non-jurisdictional utilities in the Pacific Northwest, participation in a regional planning organization has been valuable, especially as these non-jurisdictional entities otherwise would not participate in a regional market.

K

Economic, Health and Environmental Benefits Assessment of Current Conditions

This appendix describes the proposed methodology and initial assumptions for the Economic Health and Environmental Benefits Assessment per WAC 480-100-620 (9). Results will be reported in the final IRP filing after publication of the Department of Health cumulative impact analysis and further public participation.

Contents

1. OVERVIEW

The Clean Energy Transformation Act (CETA) requires utility resource plans to ensure that all customers benefit from the transition to clean energy. To achieve this goal, an Economic, Health and Environmental Benefits Assessment must be performed to provide guidance to the development of the utility's Clean Energy Action Plan (CEAP)[1] and Clean Energy Implementation Plan (CEIP).[2] The purpose of the assessment is to identify and quantify the existing conditions for all customers and to identify disparate impacts to communities within and around PSE's service territory that are related to resource planning. The goal is for the utility to propose actions and programs that are not simply lowest reasonable cost, but also distribute its benefits equitably among customers.

This appendix explains the methodology proposed to create PSE's assessment, the data sources used to define certain customer groups and the metrics used to measure current conditions; however, PSE acknowledges that these plans are preliminary. The current description is informed by PSE's understanding of the initial rulemaking drafted by the Washington Utility and Transportation Commission (WUTC), but the analysis will evolve based on the cumulative impact analysis from the Washington Department of Health expected at the end of December 2020 and on stakeholder feedback.

Proposed Strategy and Definitions

To evaluate the equitable distribution of benefits, the assessment considers the following as defined in WAC 480-100-620 (9):

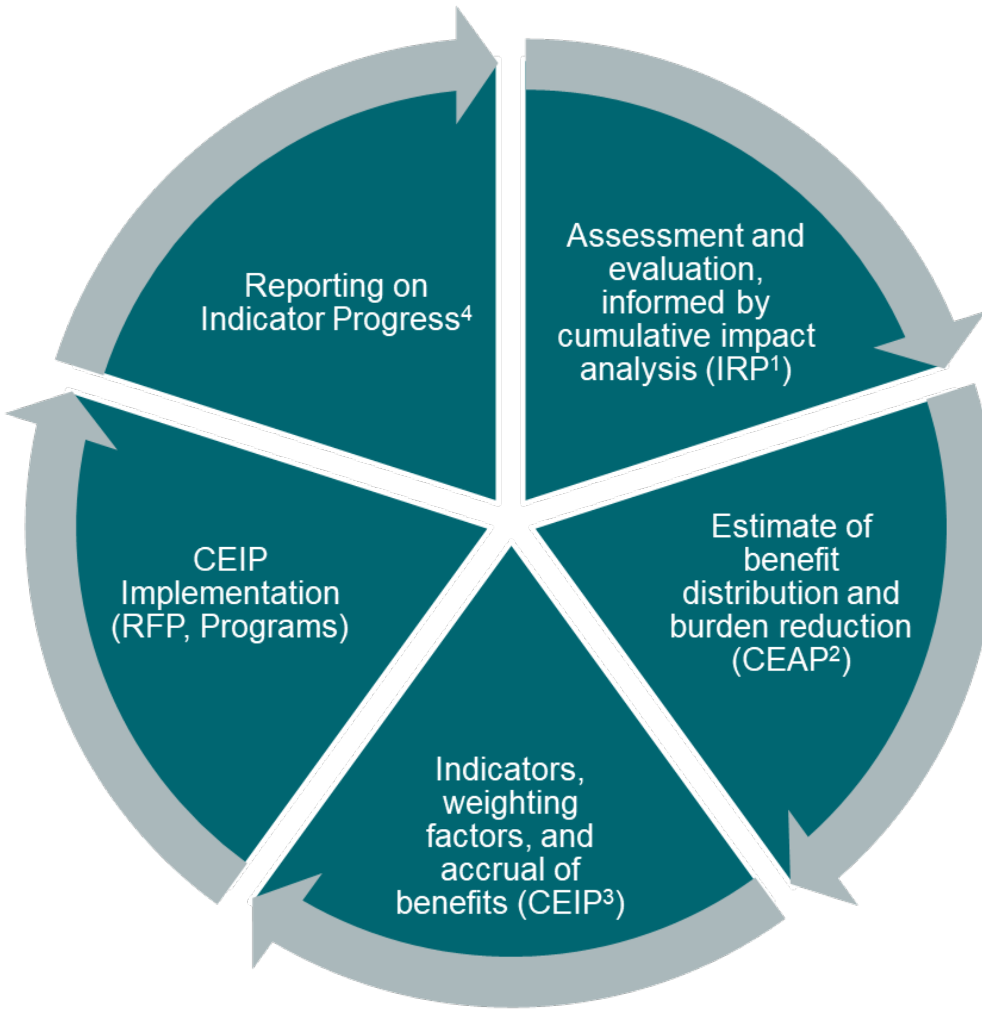
- energy and non-energy benefits and reductions of burdens to vulnerable populations and highly impacted communities
- long-term and short-term public health and environmental benefits, costs, and risks, and
- energy security risk

1 / The Clean Energy Action Plan is a 10-year outlook that achieves the clean energy transformation standards.
2 / The Clean Energy Implementation Plan identifies specific targets and actions PSE will take toward meeting the energy transformation standards.

Life Cycle Process

Figure K-1 shows the life cycle process PSE proposes to undertake in assessing customer groups, defining customer benefit indicators and reporting on progress.

Figure K-1: CETA Equitable Distribution of Benefits Lifecycle



NOTES

1. IRP Assessment and Evaluation: Draft WAC 480-100-620(9) and (11)(g)

2. CEAP Estimates: Draft WAC 480-100-620(12)(c)(ii)

3. CEIP Indicators and Weighting Factors: Draft WAC 480-100-640(4) and (5)(a)

4. Reporting on indicator progress: Draft WAC 480-100-650(1)(d)

The assessment will identify specific metrics and be informed by the cumulative impact analysis from the Washington State Department of Health, which anticipates completing this analysis by the end of December 2020; the results of that study will be reported in the Final 2021 IRP filing.

Definitions

Definitions are key to this assessment, and PSE anticipates the following definitions may change between the draft and final IRP as a result of stakeholder feedback and the Department of Health's cumulative impact report.

ENERGY BURDEN. The share of annual household income used to pay annual home energy bills.

EQUITABLE DISTRIBUTION. A fair and just, but not necessarily equal, allocation of benefits and burdens from the utility's transition to clean energy. Equitable distribution is based on disparities in current conditions. Current conditions are informed by, among other things, the assessment described in RCW 19.280.030(1)(k) from the most recent integrated resource plan.

HIGHLY IMPACTED COMMUNITIES. A community designated by the Department of Health based on the cumulative impact analysis required by RCW 19.405.140 or a community located in census tracts that are fully or partially on "Indian country," as defined in 18 U.S.C. Sec. 1151.

VULNERABLE POPULATIONS. Communities that experience a disproportionate cumulative risk from environmental burdens due to: Adverse socioeconomic factors, including unemployment, high housing and transportation costs relative to income, access to food and health care, linguistic isolation, and sensitivity factors, such as low birthweight and higher rates of hospitalization.

CUSTOMER BENEFIT INDICATOR. An attribute, either quantitative or qualitative, of resources or related distribution investments associated with customer benefits described in RCW 19.405.040(8).

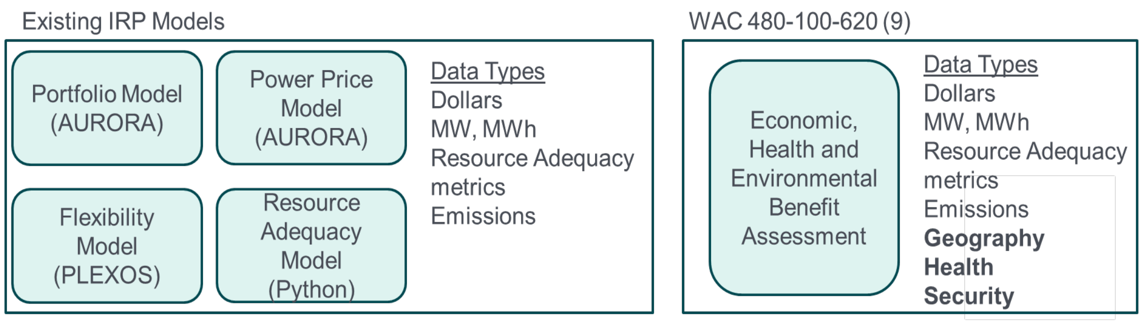
INDICATOR VS. ASSESSMENT METRIC

- Indicator shows progress as it is tied to an attribute of a resource or program.
- Assessment metrics give a snapshot in time of specific measures related to economic, health, environmental, and energy security and resiliency impacts.

2. METHODOLOGY

The IRP traditionally analyzes specific quantitative data such as cost measured in dollars, resource adequacy metrics and emissions. With the inclusion of this assessment, the IRP must also consider additional data types such as geography, health and security as shown in Figure K-2

Figure K-2: WAC 480-100-620(9) Assessment Objectives

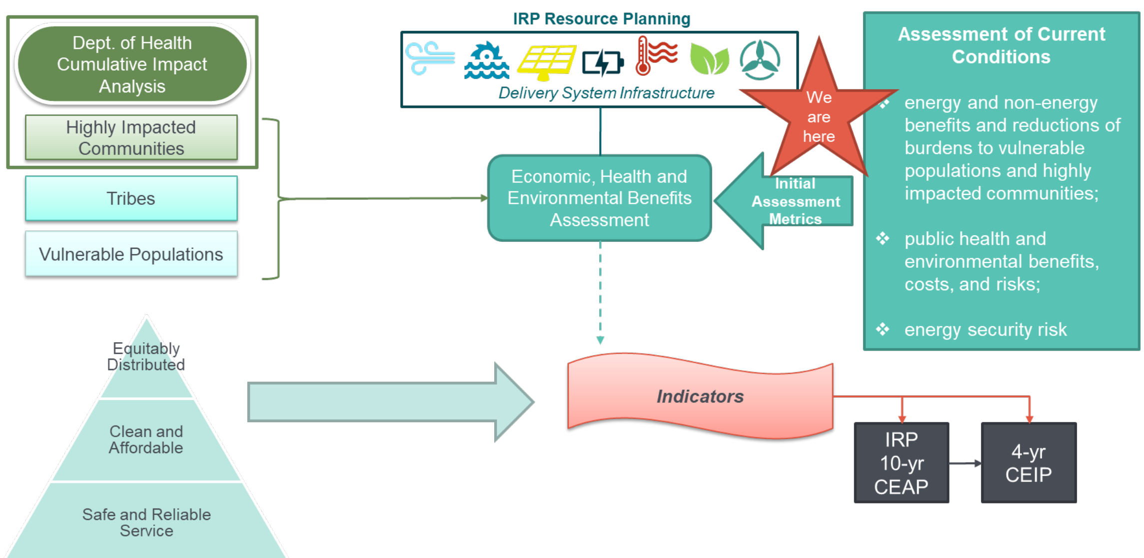


Because some of these data types are qualitative in nature, they do not necessarily align with existing IRP model framework. In order to begin to collect data and perform the analysis for this assessment, PSE has broken down the necessary steps as follows:

1. Define assessment metrics.
2. Evaluate current conditions and define highly impacted communities and vulnerable populations concurrently.
3. Compare current conditions for all PSE customers to highly impacted communities and vulnerable populations.
4. Measure disparities.

Figure K-3 was shared with stakeholders during the IRP public participation process and illustrates the role of the assessment in the IRP as well as how it relates to the Clean Energy Action Plan and the Clean Energy Implementation Plan. PSE solicited stakeholder feedback on the assessment during the IRP public process.

Figure K-3: Incorporating the Assessment into the IRP



This assessment informs the development of the CEAP and CEIP. Feedback on the actions, indicators and targets from this assessment will be captured through the CEIP.

The assessment metrics and definitions of highly impacted communities and vulnerable populations presented here are preliminary and PSE expects to update the metrics as it evolves its understanding for future assessments.

Assessment Metrics

As required by the CETA legislation and IRP/CEIP rulemaking, assessment metrics will include but not be limited to the areas of economics, health and environmental benefits. The purpose of these metrics is to quantify existing conditions observed across PSE's customers in order to evaluate disparities between populations within that customer base. PSE developed an initial set of metrics and they are included in Figure K-5. The initially proposed categories, data sources and definitions for each assessment metric are also included in Figure K-5. Proposed and available metrics are still being evaluated and may change.

Figure K-5: Summary of Proposed Assessment Metrics

PSE Defined Category	Proposed Assessment Metric	Definition	Data source
Health	Death from Cardiovascular Disease	Measures the proportion of deaths in a population due to cardiovascular disease	Wash. Department of Health (Fortress) https://fortress.wa.gov/doh/wtn/WTNIBL
	Low Birthweight	Measures the count of infants born at term with a birthweight less than 2,500 grams	
Environmental	NO_x – Diesel Emissions	Measures NOx emissions within a specific census tract area	Wash. Department of Health (Fortress) https://fortress.wa.gov/doh/wtn/WTNIBL
	Ozone Concentration	Measures the three-year, mean concentration of daily maximum 8-hour rolling averaged ozone	
	PM2.5 Concentration	Measures the 3-year, mean concentration of daily maximum PM 2.5 levels	
	Populations Near Heavy Traffic Roadways	Measures number of people exposed to air pollutants from living near busy roadways	
	$S0_2$ Levels	Emission levels tied to PSE 's owned resources	PSE, EPA COBRA Tool https://www.epa.gov/statelocalenergy/co-benefits-risk-assessment-cobra-health-impacts-screening-and-mapping-tool
	NO_x Levels	Emission levels tied to PSE 's owned resources	PSE, EPA COBRA Tool https://www.epa.gov/statelocalenergy/co-benefits-risk-assessment-cobra-health-impacts-screening-and-mapping-tool
Economic	Energy Burden of Average Customer	Percentage of household income spent on energy	Department of Energy LEAD Tool https://www.energy.gov/eere/slsc/maps/lead-tool
	Transportation Expense	Percentage of income spent by Median Income Families	Wash. Department of Health (Fortress)

PSE Defined Category	Proposed Assessment Metric	Definition	Data source
	Unemployed	Measures percentage of the population that are in the labor force and registered as unemployed	https://fortress.wa.gov/doh/wtn/WTNIBL
Energy Security & Resiliency	Resiliency metrics	*To be provided in final IRP*	PSE
	Resource adequacy metrics	*To be provided in final IRP*	

Energy Security & Resiliency. The Washington State Department of Commerce and other utilities are leveraging reliability metrics to address the consideration of energy security and resiliency. However, energy industry reports consistently highlight that reliability metrics are not a measure of resiliency. Resilience is the ability of the power grid and supply to withstand man-made and natural disasters, including weather-related events. Current working groups under the Electric Power Research Institute and Edison Electric Institute are discussing what metrics are appropriate to represent resiliency. PSE would suggest that this consideration is about preventing large-scale long-duration outages, not reducing the average number of outages across a system, but there is more work to be done.

Customer Groups

All PSE Customers

The definition for PSE customers will be based on PSE's service territory for electric ONLY customers. This full set of customers will be assessed based on the Summary of Proposed Assessment metrics from Figure K-5 to capture the current conditions across PSE's electric only customers. This snapshot will serve as a baseline from which to measure current disparities.

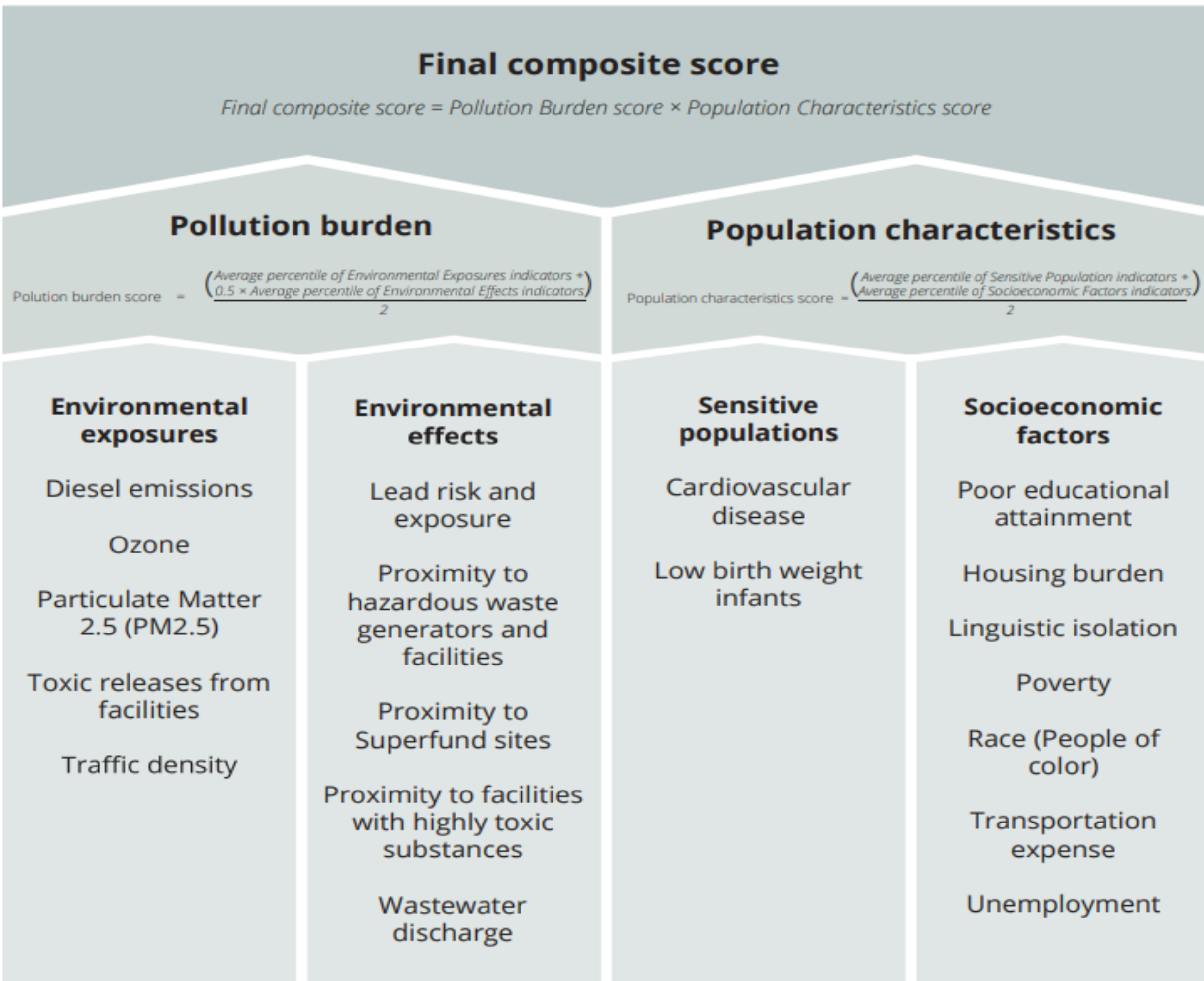
Vulnerable Populations

Vulnerable populations attributes are intended to describe disproportionate cumulative risk from environmental burdens due to:

- Adverse socioeconomic factors, including unemployment, high housing and transportation costs relative to income, access to food and health care, and linguistic isolation; and
- sensitivity factors, such as low birthweight and higher rates of hospitalization

The Washington State Department of Health developed a health disparities map and composite score as defined in the Washington Environmental Health Disparities report.[3] With the report, vulnerability is represented by indicators of socioeconomic factors and sensitive populations. The attributes listed under the sensitive populations and socioeconomic factors closely align with the definition of vulnerable populations in the rulemaking and are illustrated in Figure K-6. PSE is proposing to use some of the attributes from this list, as shown in Figure K-7.

Figure K-6: Indicators, Washington Environmental Health Disparities Map



3 / *https://www.doh.wa.gov/DataandStatisticalReports/WashingtonTrackingNetworkWTN/InformationbyLocation/WashingtonEnvironmentalHealthDisparitiesMap*

Figure K-7: Proposed Attributes for Vulnerable Populations

Indicators	Specific Attribute
Sensitive Populations	Cardiovascular disease
	Low birthweight
Socioeconomic Factors	Housing burden
	Linguistic isolation
	Poverty
	Transportation expense
	Unemployment

Highly Impacted Communities

Attributes: To be determined from Department of Health cumulative health analysis.

Tribes

Attributes: To be determined and provided in the final IRP.

3. CURRENT CONDITIONS RESULTS

[To be provided in final IRP]

4. CUSTOMER GROUP COMPARISON RESULTS

[To be provided in final IRP]

5. CUSTOMER BENEFIT INDICATORS

[To be provided in final IRP]

6. [FUTURE] DISPARITY ASSESSMENT/RESULTS

[To be provided in final IRP]

Knowledge to Shape Your Future

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Puget Sound Energy Temperature Trend Study

Submitted to:

Puget Sound Energy

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Puget Sound Temperature Trend Study

1. Overview

Over the last twenty years, there has been a growing concern about the impact of climate change on the environment, the economy, and long-term human health. It has been well-documented that the air mass and oceans are warming, contributing to more extreme weather events, and by extension, potentially catastrophic weather events in the future. In the Northwest, the Bonneville Power Authority (BPA), the Army Corps of Engineers, and the Bureau of Reclamation (*River Management Joint Operating Committee – RMJOC*) have been studying climate impact on the Columbia River Basin since 2009. The RMJOC studies, like climate-model-based studies across the country, project increasing temperatures. The Northwest Power and Conservation Council (NWPCC) has been building on this work as part of the 2021 Power Plan; updated climate scenarios based on the RMJOC analysis will be incorporated into long-term energy and demand forecasts.

Itron was contracted by Puget Sound Energy (PSE) to evaluate temperature trends in the PSE service area. Rather than basing analysis and projections on Global General Circulation Models (sometimes referred to as Global Climate Models - GCM), we have taken a data-driven approach based on historical temperature trends. Trend-based projections provide a comparison against the wide-range of temperature outcomes derived from GCM models and provide a basis for developing weather inputs for sales, energy, and peak forecast models. Itron has performed similar analyses for NVEnergy and NYISO (New York Independent System Operator). The focus on temperature trends, rather than complex interactions in climate, provides a simple, data-driven approach for analyzing and evaluating the impacts on electricity and natural gas consumption.

The primary objectives include:

- Evaluating historical temperature trends observed in PSE's service area
- Developing estimates of future temperature trends based on results of the historical temperature analysis
- Translating temperature projections into long-term Heating Degree Days (HDD) and Cooling Degree Days (CDD) used for PSE's load forecasting models
- Comparing PSE's observed temperature trends to recent regional and other climate impact studies

The focus of this work is on temperature trends. It is not a climate study. The analysis does not address other components of weather and climate, such as precipitation, snowpack, extreme weather events, or El Niño/La Niña events.

2. Summary

Our analysis shows that there is a strong and statistically significant increase in average temperature in the PSE service area. Temperatures at the Seattle-Tacoma International Airport (SEA-TAC) have been steadily increasing over the last fifty years. Itron's analysis of long-term temperature trends shows temperature increasing approximately 0.04 degrees per year or 0.4 degrees per decade. This trend is consistent with other analyses of historical temperature trends and recent Colombia River Basin climate impact study. Forecasts based on the average of past temperatures are likely to underestimate future cooling requirements and overestimate heating requirements.

While PSE average daily temperatures are increasing, peak-day temperature trends are statistically weak, but still positive. We are still likely to experience extreme cold-days consistent with the past and summer peak days that are not significantly warmer than they are today.

3. Climate Impact Studies

Increasing global temperatures have been well-documented. The majority of climatologist attribute temperature increases to a rise in anthropogenic (i.e., caused by humans) greenhouse gas concentrations.

The Intergovernmental Panel on Climate Change (IPCC), the world's leading organization on climate change, in their most recent temperature projections show that by 2100, global average temperatures increase 1.1 to 2.6 degrees Celsius for RCP 4.5 and 2.6 to 4.8 degrees Celsius for RCP 8.5 over the base-year period (1986 – 2005); this translates into roughly 0.5 to 0.9 degree (Fahrenheit) increase per decade (*Appendix A*, *Reference 1*).

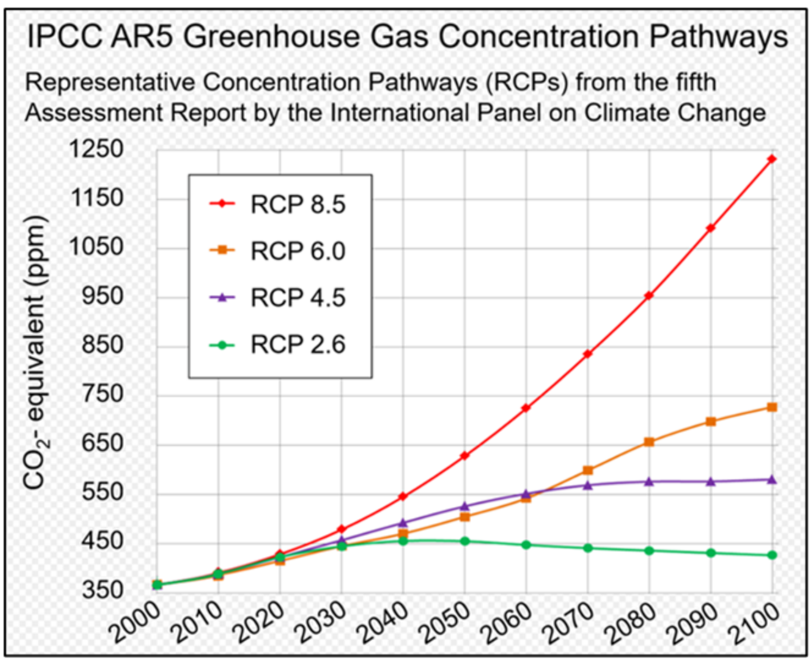
The River Management Joint Operating Committee (RMJOC) began studying the impact of climate change on the Columbia River Basin in 2009. The RMJOC includes Bonneville Power Administration, United States Army Corps of Engineers, and United States Bureau of Reclamation. The 2009 – 2011 analysis indicated that there was a strong likelihood of increasing temperatures due to anthropogenic causes. In 2013, RMJOC began work to update the study. The updated analysis and associated water flow data set was published in June 2018 (*Appendix A*, *Reference 2*). The focus of the study was on the potential impact of climate change on the Federal Columbia River Basin Power System. RMJOC concluded increasing greenhouse gases will result in increasing temperatures that in turn will contribute to declining snowpack, more of the winter runoff in the form of rain, earlier spring runoffs, lower water levels in the summer months, and greater difficulty managing the river system. The study further concluded there will be a decrease in regional heating requirements (3% to 4% in December) and an increase in cooling loads (1% to 3% in July). Depending on future greenhouse gas paths, temperatures are expected to increase 0.3 to 1.0 degrees per decade between 2010 and 2040 (*Appendix A reference 1*).

NWPCC, which is responsible for regional power planning in the Pacific Northwest, is currently working on the 2021 Power Plan. Updated climate scenarios based on the RMJOC climate modeling work were presented in April 2020. Results indicate fewer heating degree-days (HDD) and more cooling degree-days (CDD), both of which are consistent with increasing temperatures.

The basis for climate projections in the RMJOC, the NWPCC, and other climate projections are derived from Global Climate Models (GCM). There are over fifty GCMs that model the interaction between greenhouse gas, the physical environment, and solar radiation. Over the last ten years, there have been significant improvements in understanding the complex relationship between increasing greenhouse gases, air circulation, oceans and ocean currents, land and its topography, vegetation, and human activity, as a result of increased computing power, advances in data collection, and improvements in modeling. This has allowed climatologists to develop more confidence around localized climate impact results.

GCM model outputs are based on one of four greenhouse gas paths established by the IPCC. The paths reflect the greenhouse gas accumulation to reach specific Radiative Forcing (RF) levels by the year 2100. Figure 1 shows these paths.

Figure 1: GCM Greenhouse Gas Paths



RF is a measure of the difference between insolation (the amount of heat the earth absorbs from the sun) and the amount of heat released back to space. In 1750, the RF value was 0. Estimated 2018 RF value is 3.1. Most climate impact studies focus on the RF 4.5 and RF 8.5 paths. Many climatologist and studies (including the RMJOC) believe we are on the 8.5 path. Other climatologists believe that the 4.5 path is the more likely outcome. Currently, there is little divergence in these paths. Very few expect the 2.6 path, as that would imply an aggressive worldwide greenhouse gas mitigation effort. There should be a better idea as to which path we are on over the next ten years.

Each model and selected greenhouse gas path generates a different temperature path based on the underlying model structure and model inputs. Given differences in models, model inputs, and greenhouse gas path assumptions, there is a large range of possible temperature outcomes. In developing temperature and other climate variable projections, climate studies will weigh the regional output from multiple models; for the NWPCC this involved utilizing an ensemble approach across 19 GCM. References to recent climate impact studies and projected temperature trends are provided in Appendix A.

Rather than basing temperature and degree-day projections on GCM results, this study bases CDD and HDD projections on historical temperature trends. The advantage of a data-driven approach is that we can calibrate into specific regional weather data and statistically measure both trend and variance. Regional global climate modeling work provides a framework to compare against trend-based temperature projects.

4. PSE Temperature Analysis

The primary objective of this study is to estimate temperature trends for the PSE service area and to develop normal heating degree-days (HDD) and cooling degree-days (CDD) that reflect estimated temperature trends. Temperatures in the PSE service area are increasing approximately 0.4 degrees per decade. With increasing temperatures, HDDs can be expected to decline and CDDs to increase.

Our approach was developed as part of the climate impact study conducted for the New York ISO. The study estimated temperature trends for over twenty-weather stations across the state with simple linear trend regression models. Temperature trend coefficients derived from the regression equations were used in calculating regional trended normal heating and cooling degree-days. Daily, monthly, and peak degrees were then used in estimating long-term end-use load models and developing long-term hourly load forecasts for each of the New York ISO planning zones (*Appendix A, Reference 3*).

Estimate Temperature Trends

The PSE temperature analysis is based on reported temperatures for the Seattle-Tacoma International Airport (SEA-TAC) for the period 1950 through 2019. Annual average, maximum, and minimum temperatures are calculated from the historical hourly temperature data. While we evaluated a number of temperature concepts, we ultimately focused on:

- Average annual temperature
- Minimum temperature during peak winter heating period
- Maximum temperature during peak summer cooling period

Average Annual Temperature. Temperature trends are estimated using simple linear regression models that relate temperature to time as measured by a linear trend variable.

Figure 2 shows the calculated average temperature trend and coefficient statistics. The light-blue line shows the 90% confidence interval. The model is estimated with annual average temperature starting in 1950.

Figure 2: Average Annual Temperature Trend

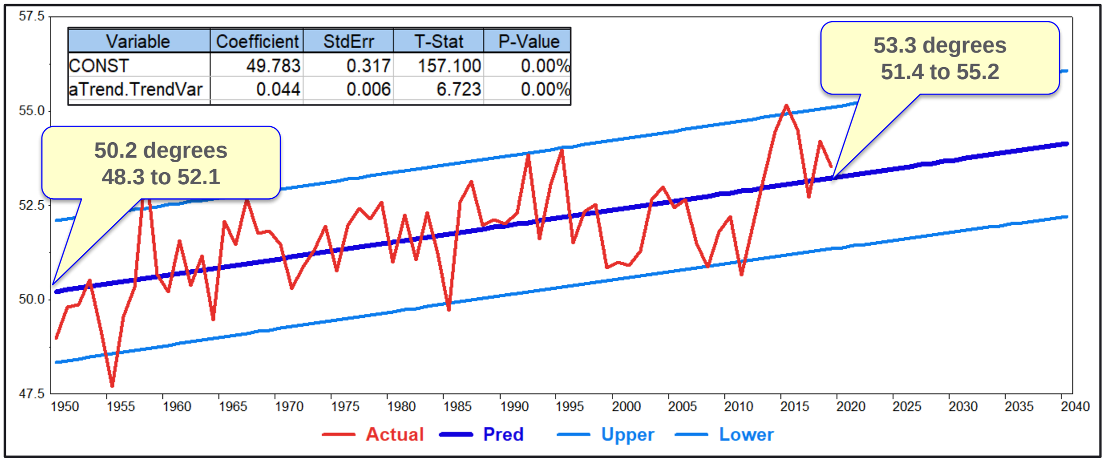


Figure 2 shows a positive and statistically significant temperature trend with a T-Statistic of 6.7 and a P-Value of 0.0%. The estimated trend coefficient is 0.044; this implies that over the estimation period, average temperatures have been increasing 0.044 degrees per year or 0.44 degrees per decade. Given the model standard error, at the 90% confidence level, temperatures have been increasing 0.34 to 0.54 degrees per decade. The expected temperature in 1950 was 50.2 degrees compared with 53.2 degrees in 2019. Expected average temperature increased 3 degrees over this period.

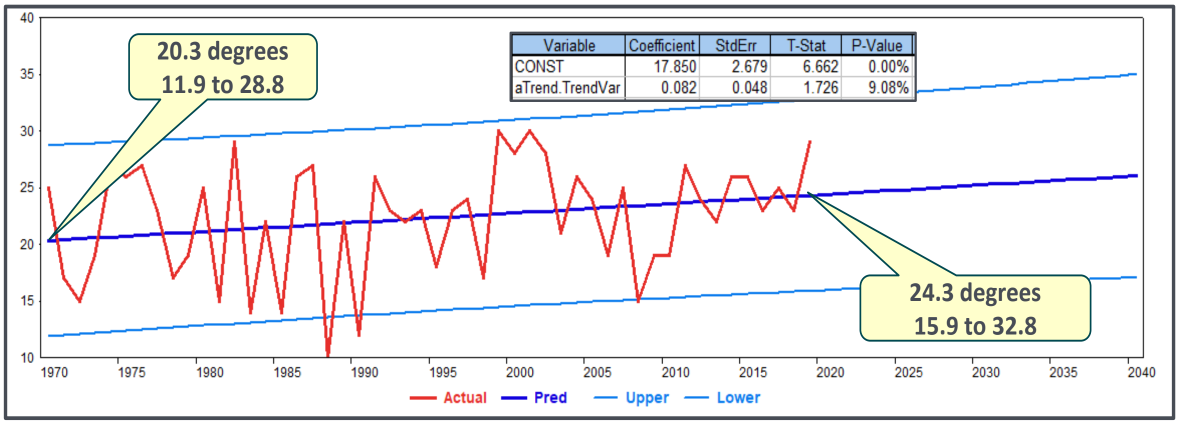
In the New York study, there was some discussion as to whether the temperature trend was linear or in-fact increasing at a faster rate over time. We evaluated a number of functional forms, but in the end, concluded that temperatures are best explained by a linear trend. This is also the case with PSE; there is no indication that changes in temperature are accelerating.

Over the last seventy years, temperature measurement has been impacted by changes in measurement location and measuring equipment (e.g., transitioning from analog to digital measurement). Shortening the estimation period to 1970 (i.e., 50 years) results in 0.037 degrees per year (0.37 degrees per decade). Depending on the start year, the estimated trend coefficients vary from 0.33 to 0.47; all within the 90% confidence interval. The average across the different estimation periods is approximately 0.4 degrees per decade.

The impact of increasing temperatures on energy demand largely depends on the sensitivity of electricity or natural gas use to changes in temperature. PSE is a winter-peaking utility with significant electric and natural gas heating load; winter energy requirements are strongly correlated with winter temperatures. The relationship of summer loads and temperatures are relatively weak given low cooling load requirements due to generally mild summer temperatures. Increasing temperatures will have a stronger impact on the heating side in the form of decreasing HDD while increasing CDD are likely to have only a small impact on cooling-related energy use. As a result of increasing temperatures, HDD can be expected to decline on average 0.5% per year; ultimate impact on sales will depend on customer-class size and usage-sensitivity to changes in HDD.

Winter Heating Peak Temperature. PSE is most concerned with minimum temperature trends as it is cold-day temperatures that drive heating requirements and system peak. PSE uses minimum temperatures for hours 8 to 21 for the heating season (November to February) to define the peak temperature. Figure 3 shows the minimum winter temperature trend for the hours when peaks can occur.

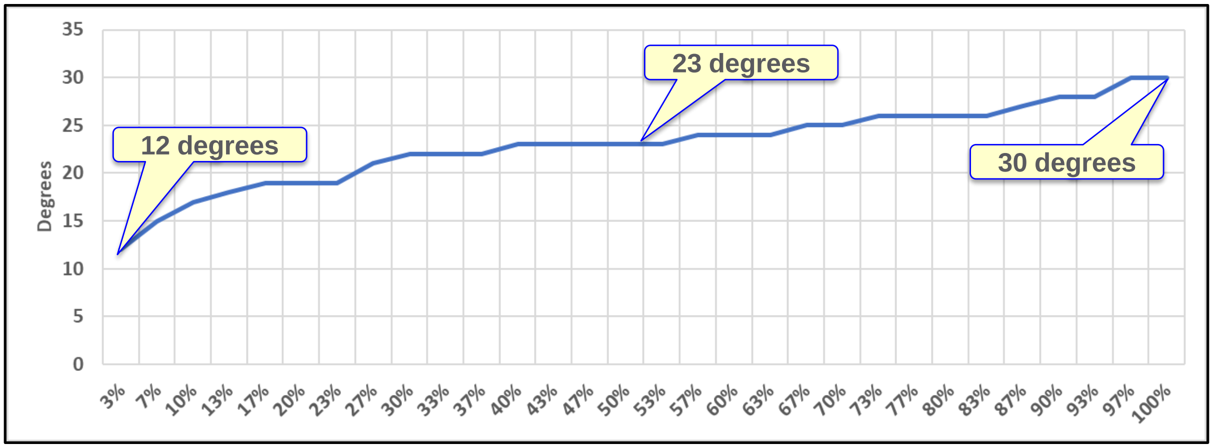
Figure 3: Winter Peak Temperature Trend



Starting estimation from 1970, the winter peak temperature is increasing 0.082 degrees per year or 0.82 degrees per decade. While this is faster than average temperature, the standard error is significantly larger, resulting in a relatively large 90% confidence interval around the minimum temperature trend. The expected minimum temperature in 1970 of 20.3 degrees is still within the 2020 90% confidence interval. This has implications when considering the appropriate assumptions for modeling peak-day weather impacts.

PSE electric system demand peaks in the winter period. The peak demand is largely driven by peak-day minimum temperatures. PSE currently plans for an expected peak-day temperature of 23 degrees. The 23-degree design day is based on the minimum winter temperature that occurred in each of the last 30-years. This is depicted in Figure 4 **Error! Reference source not found.**.

Figure 4: Winter Minimum Peak-Day Temperature (30-years, ranked low to high)

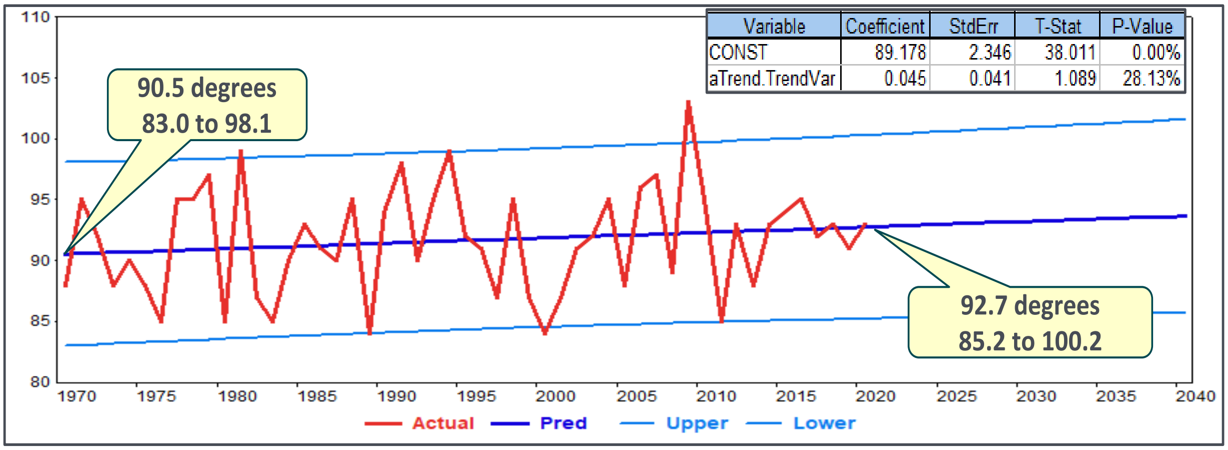


The coldest temperature in each year is ranked from the lowest temperature (12 degrees) to the highest minimum temperature (30 degrees). PSE plans system peak for the median of the data series -- 23 degrees, which is also the mean for this data series, as well as the mode, with 5 out of the last 30 years experiencing a day where minimum temperature fell to 23 degrees.

Based on the minimum temperature trend model, the expected minimum winter temperature in 2019 is 24.4 degrees with a 90% confidence interval of 16.4 degrees to 32.4 degrees. The current 23 degree-design temperature falls well within this range. Given the large number of occurrences where this temperature actually occurred, it is appropriate to plan for a 23 degree minimum temperature day even as minimum temperatures continue to rise. Calculating winter peak-day normal weather conditions based on the prior thirty years is a reasonable approach.

Summer Cooling Peak Temperature. The summer peak temperature is defined as the highest temperature over the summer cooling hours. This includes hours 8:00 to 20:00 for the months July and August. Figure 5 shows the summer maximum temperature trend starting in 1970 for the hours when peak occurs.

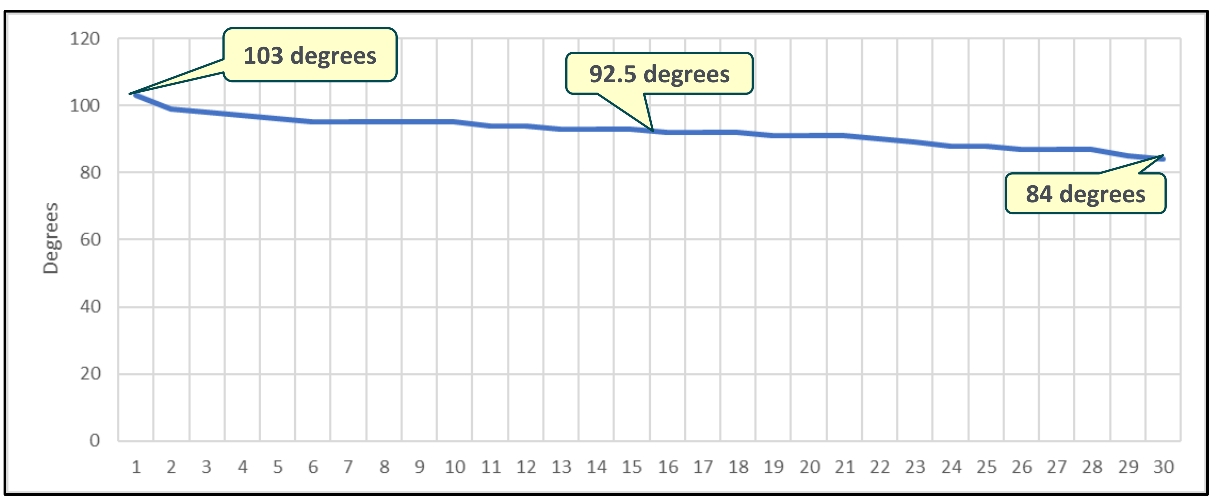
Figure 5: Summer Peak Temperature Trend



While the summer maximum temperature trend is positive at 0.45 degrees per decade, it is statistically significant only at the 70% level of confidence. For PSE, these translates into a wide expected summer peak temperature range with a 90% confidence bound of 85.2 to 100.2 degrees in 2020.

Figure 6 shows the peak-day temperature for the summer months (July through August). Temperatures are ranked from the highest peak-day temperature (103 degrees) to the lowest annual peak-day temperature (84 degrees).

Figure 6: Summer Peak-Day Temperature (30-years, ranked high to low)



The summer peak demand design temperature is defined as the median summer peak-day temperature (the midpoint of the temperature curve). The median temperature for the last 30 years is 92.5 degrees. As discussed above, the summer peak temperature trend is statistically weak and as a result there is a wide 90% confidence interval around the temperature trend line. The expected temperature based on the summer peak temperature trend line is 92.7 degrees with a minimum expected temperature of 85.2 degrees and a maximum expected temperature of 100.2 degrees. The 92.5 design temperature falls within the 90% confidence interval. Even as far out as 2040, the summer design temperature is well within the 90% confidence interval.

Temperature Trend Comparisons

In addition to New York, we have evaluated temperature trends for several utility service areas across the country, with estimated average temperature trends varying from 0.4 to 1.0 degrees per decade. In all cases, the average temperature trend is statistically significant. A recent study by the Penn Institute for Economic Research (PIER) found similar results (*Appendix A, Reference 4*). Table 1 shows average degree-day per decade derived from the PIER study.

Table 1: Estimated Temperature Trends

City	Station	TempChg	Per Decade
Atlanta	ATL	4.36	0.76
Boston	BOS	2.06	0.36
Baltimore	BWI	2.25	0.39
Cincinnati	CVG	2.53	0.44
Dallas-Fort Worth	DFW	3.44	0.60
Des Moines	DSM	3.93	0.69
Detroit	DTW	4.09	0.72
Las Vegas	LAS	6.05	1.06
New York (LGA)	LGA	4.03	0.71
Minneapolis	MSP	4.72	0.83
Chicago	ORD	2.86	0.50
Portland	PDX	2.55	0.45
Philadelphia	PHL	4.78	0.84
Salt Lake City	SLC	3.92	0.69
Tucson	TUS	4.89	0.86
Median		**3.93**	**0.69**

The median temperature trend across the 15 cities evaluated is 0.7 degrees per decade. Temperature trends varied from 0.36 degrees (Boston) to 1.06 degrees (Las Vegas). The highlighted cities show temperature trends close to what was estimated for the PSE service area. Like Seattle-Tacoma, these cities are in close proximity to the ocean, where temperature increases have tended to be lower.

While the PIER study measured average temperature trend, the primary focus was the diurnal temperature range (DTR); the DTR is the difference between the maximum and minimum temperature; the PIER study found a statistically significant decline in DTR across the sample cities. Other earlier work showed decline in DTR is largely the result of nighttime low temperatures increasing faster than daytime high temperatures.

Summary. The average temperature has been showing a strong statistical increase over the last fifty years in the PSE service area and across the country. PSE winter heating peak temperature is increasing faster than average PSE temperature, though there is a larger variance in expected minimum temperatures when evaluated for the 90% confidence interval.

While the summer cooling peak temperature is increasing, the trend is statistically weak. In other studies, we have found similar results where there has generally been a small positive maximum temperature trend, but the trend is statistically weak. Evidence from the PIER study and our analysis of other service areas indicate that it is largely increased in overnight minimum temperatures that are contributing to long-term overall temperature increase.

5. Translating Temperature Trends to Degree-Days

Electric and natural gas sales are significantly impacted by heating and cooling requirements. In electric and natural gas load modeling, the weather impact is generally captured by heating degree-days (HDD) and cooling degree-days (CDD). Actual HDD and CDD are key variables in usage models with expected HDD and CDD used in projecting future demand and isolating weather-related sales for variance analysis. HDD are designed to capture heating requirements and CDD cooling requirements. HDD and CDD are often referred to as spline variables as they only take on a positive value when a specified condition is met. For example, HDD with a 65 degree temperature base, only takes on a positive value when the average temperature is ***below*** 65 degrees. If the average daily temperature is 50, then HDD is 15 (i.e., 65 degrees – 50 degrees = 15); if the temperature is 65 or greater HDD equals 0. CDDs are the opposite; CDD have a positive value when temperatures ***exceed*** a defined reference temperature. For a CDD with a 65-degree reference point, a day with average temperature of 70 degrees results in a CDD of 5 (70 degrees – 65 degrees = 5); if the temperature is 65 degrees or lower CDD equals 0.

The following are the formulas for CDD and HDD, both with a base temperature of 65 degrees:

$$CDD65_d = Max(T_d - 65, 0)$$
$$HDD65_d = Max(65 - T_d, 0)$$

Where:

T = Average Daily Temperature
d = Date

Calculating Normal Degree Days. Normal HDD and CDD reflect our best expectation of future weather conditions and associated heating and cooling energy requirements. Normal degree-days also provide the basis for evaluating the weather impact on current electricity and natural gas sales. Normal HDD and CDD are calculated as an average of past weather conditions; we assume that the best estimate for future weather conditions is an average of past conditions. The industry standard has been to derive normal degree days using a 30-year historical period. Many utilities have moved to a 20-year and even 10-year normal period in recognition that temperatures are increasing; the shorter estimation period gives more weight to the current, warmer temperatures.

PSE calculates normal weather using the most current 30-year period. The current period is 1990 to 2019. PSE captures some of the increasing temperatures over time as the 30-year period is updated each year.

PSE uses a standard approach for calculating normal HDD and CDD for a range of temperature breakpoints. PSE first calculates daily HDD and CDD from historical daily average temperatures. The daily degree days are then averaged by date (i.e., average all the January 1st values, average all the January 2nd values, ..., average all the December 31st values) across the 30 years of historical weather data. The result is an average (or normal) daily degree-day series (366 values, including leap-year) for each temperature breakpoint concept. The normal daily degree-days are summed to derive calendar-month and annual normal HDD and CDD. Daily normal degree-days that reflect the billing period are derived by combining the meter read schedule and daily normal degree-days.

Table 2 shows calculated calendar-month and annual normal degree-days for different temperature breakpoints.

Table 2: PSE Normal Degree-Days (1990 -2019)

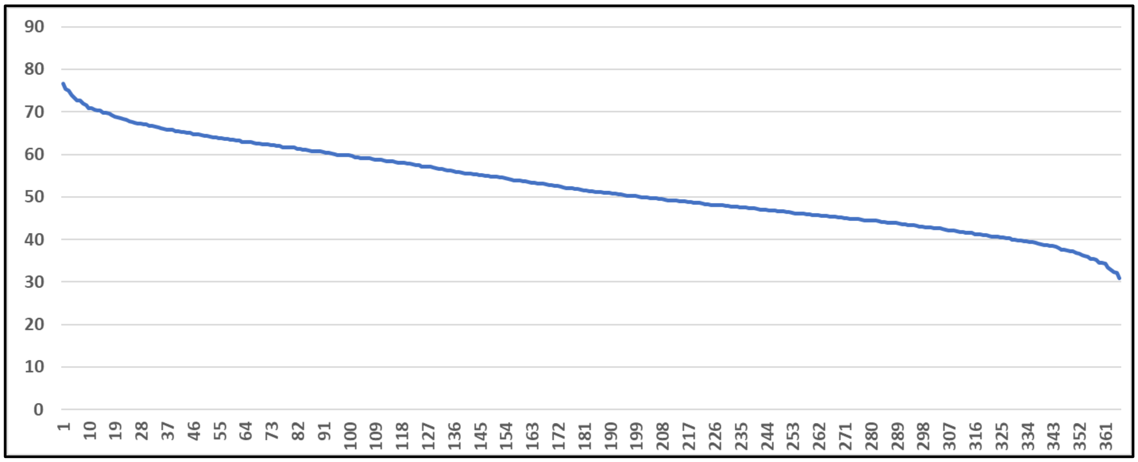
Month	HDD55	HDD60	HDD65	CDD60	CDD65
Jan	404.3	559.3	714.3	-	-
Feb	348.8	493.8	638.8	-	-
Mar	279.2	432.2	586.7	0.6	0.2
Apr	165.5	303.2	450.2	3.7	0.7
May	53.8	153.6	287.2	28.2	6.9
Jun	7.6	54.9	159.9	70.8	25.7
Jul	0.1	6.8	53.8	186.5	78.5
Aug	-	3.5	44.7	185.4	71.6
Sep	4.0	40.0	135.2	71.5	16.8
Oct	101.4	236.3	389.5	1.8	-
Nov	282.4	430.7	580.6	0.0	-
Dec	434.0	588.8	743.8	-	-
Total	**2,081.2**	**3,303.0**	**4,784.8**	**548.5**	**200.3**

Based-on the most recent 30 years, there are 2,081 normal HDD with a 55 degree-day base and 200 CDD with a 65 degree-day base. As summer weather conditions are mild in the PSE service territory, there are relatively few CDD.

Since temperatures have been increasing, the 30-year average is more representative of 2005 weather conditions (i.e., the mid-point of the 30-year normal estimation period) than 2019 weather conditions. By 2019, we would expect to see fewer HDD and more CDD than those derived from the 30-year average.

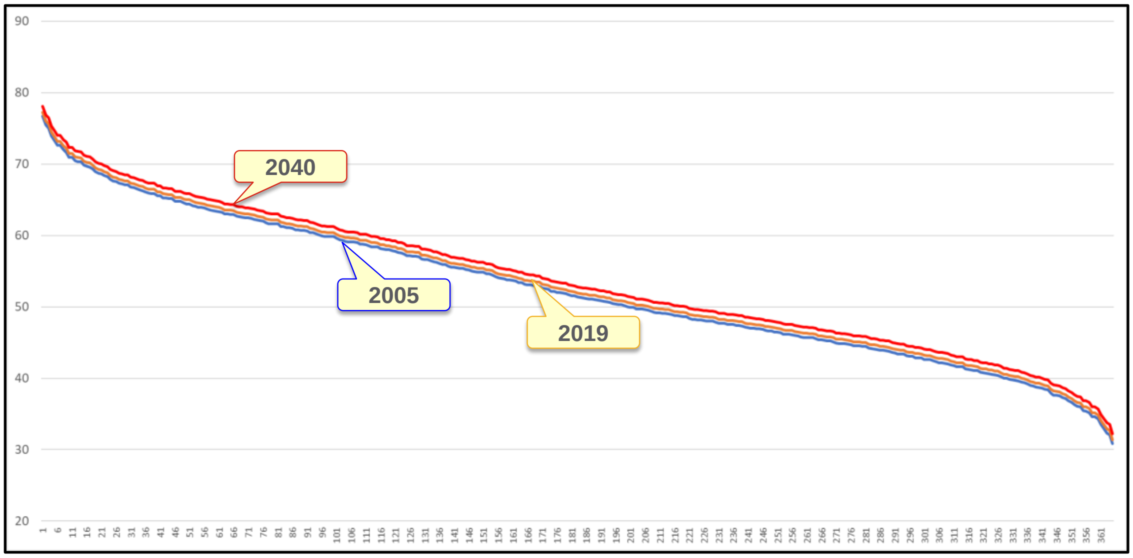
Calculating Trended-Normal Degree-Days. Trended normal HDD and CDD are derived for the PSE 0.4 degree/decade average temperature trend. The process starts with a 30-year average daily temperature series (366 observations) for the same 30-year period (1990 to 2019). Normal HDD and CDD are derived from average temperature (as opposed to daily degree-days) in order to calculate the impact of the temperature trend over time. The starting-year normal daily temperatures are derived using rank-and-average by month; in this process daily temperatures are ranked from the highest temperature to the lowest temperature within each month and then averaged across the monthly rankings. This results in an average temperature duration as depicted in Figure 7.

Figure 7: Average Daily Temperature (1990 - 2019)



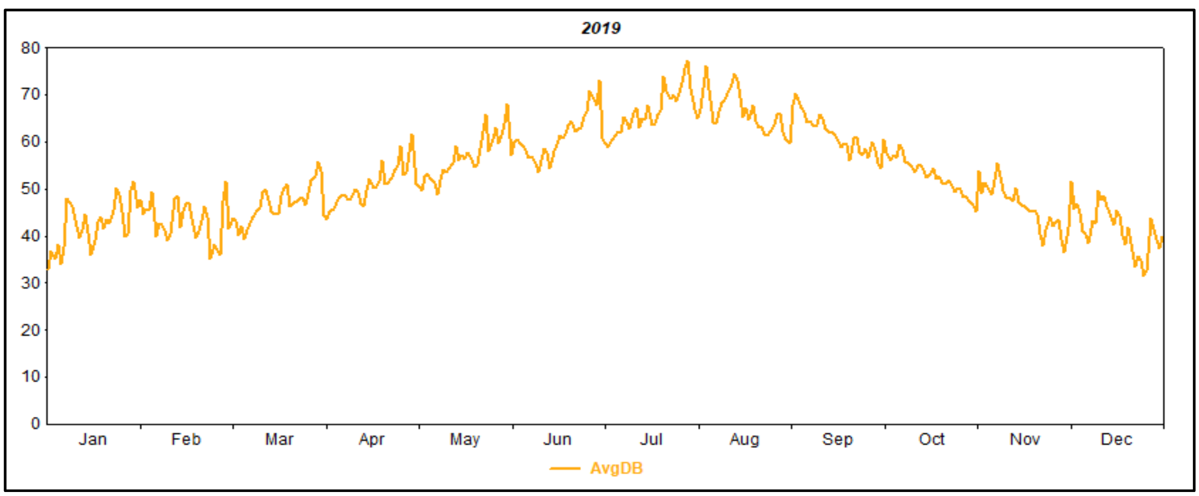
We assume that this curve best represents the average temperature in 2005 (the midpoint of the 30-year period). The normal daily temperature curve is then shifted out 0.04 degrees per year or 0.4 degrees per decade. Figure 8 shows the starting duration curve in 2005, the curve in 2019, and the curve in 2040.

Figure 8: Adjusted Temperature Duration Curves



The normal temperature curves are mapped to a typical calendar-year pattern as depicted in Figure 9.

Figure 9: Normal Daily Temperature Profile (2019)



The normal temperature profiles incorporate the expected temperature trend. The data set is used in generating daily normal degree days. Any aggregation bias (as a result of calculating normal degree-days from normal daily temperatures) is corrected by calibrating the start year (2005) to the PSE 30-year normal degree-days. Figure 10 and Figure 11 show resulting monthly HDD for a 55-degree base and CDD for 65-degree temperature base.

Figure 10: Trended Normal HDD (Base 55 Degrees)

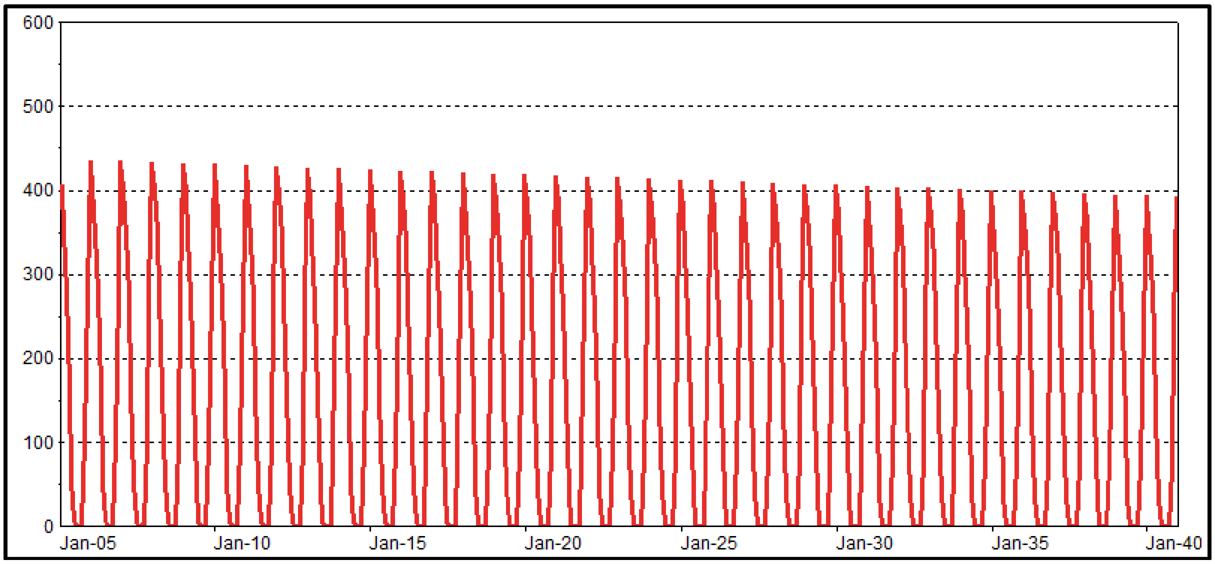


Figure 11: Trended Normal CDD (Base 65 Degrees)

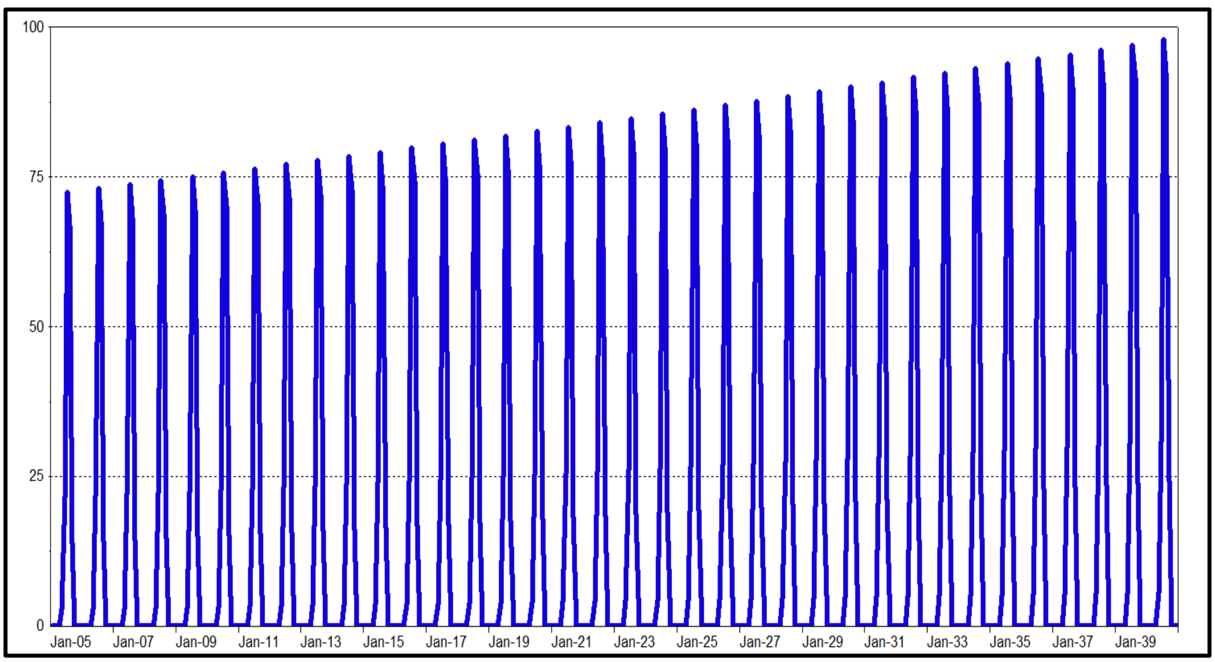


Table 3 shows a comparison of 2020 trended normal degree-days against the 30-year normal.

Table 3: 30-Year Normal and Trended Degree Days

	HDD 55 Degrees		CDD 65 Degrees	
Month	**30-Yr Nrm**	**Trended Nrm**	**30-Yr Nrm**	**Trended Nrm**
Jan	404.3	385.5	-	-
Feb	348.8	336.1	-	-
Mar	279.2	260.8	0.2	-
Apr	165.5	149.4	0.7	-
May	53.8	43.9	6.9	4.0
Jun	7.6	4.6	25.7	25.3
Jul	0.1	-	78.5	82.7
Aug	-	-	71.6	77.0
Sep	4.0	1.7	16.8	17.9
Oct	101.4	87.3	-	-
Nov	282.4	264.5	-	-
Dec	434.0	415.2	-	-
Total	**2,081.2**	**1,948.9**	**200.3**	**206.8**

By 2020 trended HDD with a 55-degree temperature base are 6.4% lower than the thirty-year normal. Assuming average temperatures continue to increase 0.4 degrees per decade, by 2030 the number of HDD are 10% below the 30-year normal and 15% below the 30-year normal by 2040.

While the July trended CDD 65 degree-day base are 5% higher than the 30-year normal and August is 7% higher, the total annual CDD increase is relatively small. May and June trended CDD are slightly lower than the 30-year normal as a result of the normal temperature mapping to the calendar year profile.

6. Conclusions

Electricity and natural gas sales are strongly impacted by weather conditions. Forecasts thus require assumptions of future weather conditions. The traditional approach is to assume that future temperatures will look like the recent past. Long-term energy and demand forecasts are generally based on HDD and CDD derived from averages of historical temperature data. In our most recent benchmark survey, 76 percent of the survey respondents based normal HDD and CDD on 20 to 30-years of historical temperature data. Twelve percent of the respondents based normal temperatures off of 15-years of historical temperature data and 10 percent used ten-years of historical temperature data. PSE currently uses the most recent thirty-year period for calculating normal HDD and CDD.

Utilities are just beginning to evaluate the impact of increasing temperatures on electric and natural gas loads. Our survey shows 12% or respondents are considering $C0_2$ emission targets and 16% are making climate change adjustments. The normal weather survey response is provided in Appendix B.

Data shows that temperatures have been increasing across the country. Average temperatures in the PSE service area have been increasing since at least the 1950s. On average, temperatures are increasing 0.4 degrees per decade. Compared with other regions, this is a relatively slow rate of increase; increases in temperatures are likely lower given PSE/Seattle's proximity to the Pacific Ocean. While average temperature is increasing, the maximum temperature has been relatively muted; as in other regions, it appears most of the average temperature gain is due to increasing minimum temperatures.

Nearly all climate models show temperatures are likely to increase through 2100. Our estimate for PSE service area is close to the RMJOC lower temperature projections based on the RCP4.5 greenhouse gas path. RMJOC, like many organizations, believes that the RCP8.5 path represents "business as usual" and as a result could see significantly higher temperatures that begin to increase at a faster rate than the historical trend. At this point, there is no evidence to support future temperatures will increase at a faster rate. For energy forecasting and weather normalization, it is reasonable to assume that expected HDD will be lower today than thirty-year average HDD, and CDD will be higher than the thirty-year average. Temperatures will likely continue to increase 0.4 degrees per decade; trended-normal HDD and CDD can be estimated to reflect this trend.

While minimum temperatures are increasing, PSE's current method for calculating winter peak-day weather is reasonable. Five of the last 30 years saw years in which the winter minimum temperature fell to 23 degrees. The 23-degree design day is also well within the expected peak-day temperature range. The summer peak-day design temperature is also within the 90% confidence interval. As the 90% summer confidence interval is quite wide, the summer design day temperature is within the 90% confidence interval as far out as 2040.

Appendix A: References

1. IPCC, Long-Term Climate Change: Projections, Commitments, and Irreversibility, 2018. https://www.ipcc.ch/site/assets/uploads/2018/02/WG1AR5_Chapter12_FINAL.pdf

2. Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RJOC-II). Part 1: Hydroclimate Projections and Analysis. June 2018. https://www.bpa.gov/p/Generation/Hydro/hydro/cc/RMJOC-II-Report-Part-I.pdf

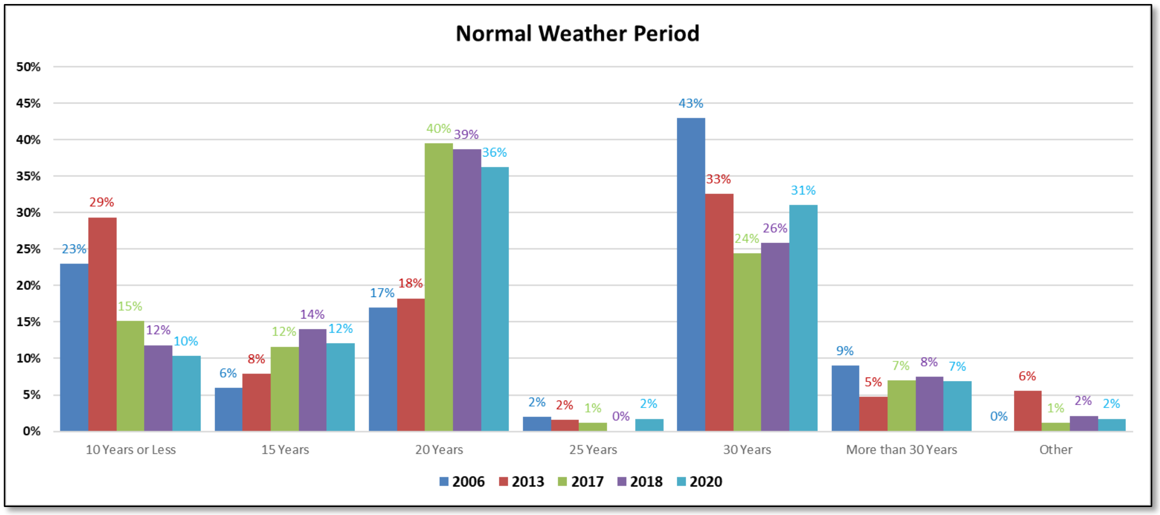
3. *New York ISO Climate Change Impact Study – Phase 1: Long-Term Load Impact*. Itron Inc., December 2019. https://www.nyiso.com/documents/20142/10773574/NYISO-Climate-Impact-Study-Phase1-Report.pdf/01fc1353-38cb-b95d-60c2-af42a78bff50

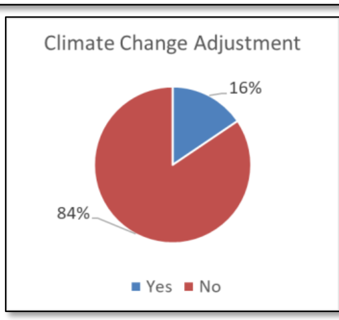
4. *On the Evolution of U.S. Temperature Dynamics*, July 2019. Francis Diebold, University of Pennsylvania, Glenn Rudebusch, FRB San Francisco. Penn Institute for Economic Research (PIER). https://economics.sas.upenn.edu/pier/working-paper/2019/evolution-us-temperature-dynamics

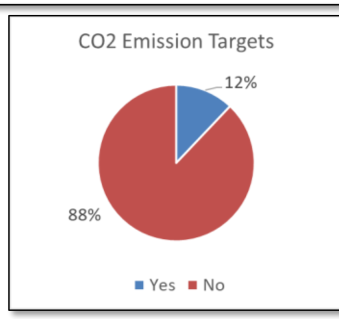
5. New York ClimAid Study. NYSERDA, 2014. Horton, R., D. Bader, C. Rosenzweig, A. DeGaetano and W.Solecki. 2014. *Climate Change in New York State: Updating the 2011 ClimAID Climate Risk Information. New York State Energy Research and Development Authority (NYSERDA), Albany, New York*). https://www.nyserda.ny.gov/About/Publications/Research%20and%20Development%20Technical%20Reports/Environmental%20Research%20and%20Development%20Technical%20Reports/Response%20to%20Climate%20Change%20in%20New%20York

6. The *California Fourth Climate Change Assessment, August, 2018.* http://www.climateassessment.ca.gov

Appendix B: 2020 Itron Benchmark Survey







- 20- and 30-year normal weather are the dominate normal weather periods.
- Few companies recognize climate issues in their forecast.

M Delivery System 10-year Plan

This appendix presents the 10-year electric and gas PSE owned delivery infrastructure plans.

Contents

1. OVERVIEW

The Delivery System is planned to improve reliability, increase capacity to serve growing load and meet regulatory requirement such as NERC TPL standards and the planning requirements relative to operating contingencies. A detailed description of the 10 year plan which includes the identification of technology, process, pilots, distribution and specific major electric and natural gas project infrastructure improvements on the delivery system within PSE's service territory are described in this section.

PSE's 10 year plan discussion will continue to mature to full intent of RCW 19.280.100 (2) (e) over the next several IRP cycles, elaborating on data gathered, market research, and cost/benefit studies that are used to develop the plan. Additionally, PSE's plans regarding stakeholder engagement described in Appendix A, Public Participation, will add input and feedback to be described in the future. PSE is active with many expert and science based research organizations such as the Western Energy Institute, Edison Electric Institute (EEI), Electric Power Research Institute (EPRI), in distribution planning, DER, and resiliency groups, leveraging studies and tools regularly, , . Future discussion will expand on these sources of expertise. Finally, PSE will continue to build on its robust delivery system planning and optimization process leveraging strong cost benefit analysis and rigor to further sensitivity and scenario constructs and integration with the IRP planning processes.

For specific projects this includes a summary of the need and solution for each project as well as detailed descriptions of recently completed non-wire or non-pipe alternative analysis for key focus projects. The discussion identifies those project that are in the implementation phase versus projects in the imitation phase. The initiation phase includes the development of the need and evaluation of alternatives and identification of a proposed solution. The implementation phase includes project planning for which the need and proposed solution is tested and then design, permitting and construction begins. Once a project is in implementation, location specific activities begin, including the engagement with the local community. Information updates are provided through the IRP process for projects in this phase. PSE is working to develop more detail and engagement with the IRP stakeholders occurs when a project is initiation.

2. ELECTRIC DELIVERY SYSTEM

Existing Electric Delivery System

NOTE: An update of this section will be included in the final IRP.

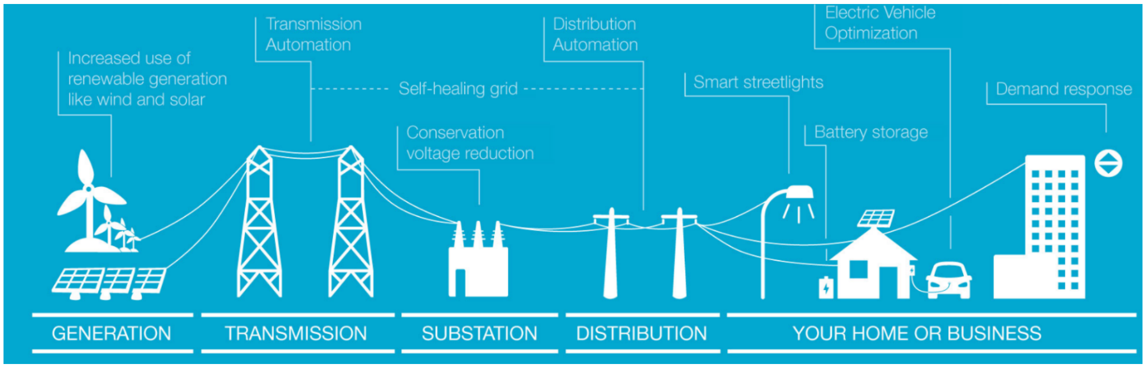
The table below summarizes PSE's existing delivery infrastructure as of December 31, 2018. Electric delivery is accomplished through wires, cables, substations and transformers.

Figure M-1: PSE-owned Transmission and Distribution Systemas of December 31, 2018

ELECTRIC
Customers: 1,157,496
Service area: 4,500 square miles
Substations: 353
Miles of transmission line: 2,620
Miles of overhead distribution line: 10,662
Miles of underground distribution line: 13,691
Transmission line voltage: 55-500 kV
Distribution line voltage: 4-34.5 kV
Customer site voltage: less than 600 V

How the Electric Delivery System Works

Figure M-2: Illustration of Electric Delivery System



Electricity is transported from power generators to consumers over wires and cables, using a wide range of voltages and capacities. The voltage at the generation site must be stepped up to high levels for efficient transmission over long distances (generally 55 kV to 500 kV).

Substations receive this power and reduce the voltage in stages to levels appropriate for travel over local distribution lines (between 4 kV and 34.5 kV). Finally, transformers at the customer's site reduce the voltage to levels suitable for the operation of lights and appliances (under 600 volts). Wires and cables carry electricity from one place to another. Substations and transformers change voltage to the appropriate level. Circuit breakers prevent overloads, and meters measure how much power is used. Distributed energy resources such as wind, solar and biodigesters are being added to the distribution system.

The electric grid, first built 1889, expanded in a highly radial, one-way flow design. Over time, the transmission system was looped in a network manner as outages across the nation drove voluntary standards and eventually regulations requiring operations with one or more elements out of service. In urban areas, a distribution system with looped feeders became common practice to improve reliability. It still operated in a radial, one-way flow manner, but as automation and protection devices mature, some parts of the distribution system are able to automatically switch to a different source.

Nearly 100 percent of the transmission system is networked and over 80 percent of PSE's distribution system is looped.

10-year Electric Infrastructure Plan Summary

NOTE: An update of this section will be included in the final IRP.

Figure M-3 summarizes the ten-year electric infrastructure plan that will be further discussed in this section. The additions described below in general terms are intended to indicate the scope of investment that may be required over the next ten years to serve our customers reliably and fulfill regulatory requirements.

Figure M-3: Summary of 10-Year Electric Infrastructure Plan

ASSET	DESCRIPTION
Foundational Technology	Advance Metering Infrastructure (AMI) Advanced Distribution Management System (ADMS)
Smart Equipment	600 SCADA devices
New Transmission Lines	104 miles
Upgraded Transmission Lines	122 miles
New Bulk Power Substations	Up to three
New Distribution Substations	Eight
Upgraded Distribution Substations	Four
Distribution Lines	48 lines
Cable Replacement	1,400 miles
Pole Replacement	7,000

Short-range Electric Infrastructure Plans (1 to 3 Years)

PSE will continue to focus on objectives that include maintaining customer and public safety, meeting electric growth and service needs, enhancing electric reliability and resiliency, and pursuing operational excellence and continuous improvements to meet customer expectations. PSE will continue to improve the planning process. PSE anticipates more clarity regarding energy security and resiliency will come from the CEIP and assessment process that will highlight areas or specific locations that should have increased resiliency such as emergency, transportation, and financial.

In the next decade, PSE will modernize the grid through investments in tools, technology, and infrastructure.

PSE will continue work on improving reliability as well as installing smart equipment for increasing the resiliency of the grid. PSE expects to replace the remaining underground high molecular weight, failure-prone distribution cable, and address approximately 7,000 poor health poles identified through inspections. Additionally, PSE anticipates replacement of several major substation components as a result of ongoing inspection and diagnostics and anticipates the need to build approximately eight new distribution substations to serve load beyond what the existing substation capacity can serve and upgrade approximately four existing substations to replace aging infrastructure and adding additional capacity to serve local load growth. The new or expanded substations will require 48 new or reconfigured distribution lines. PSE anticipates the need to proactively and programmatically address customer transformers in anticipation of increasing electric vehicle charging and circuit improvements to support increasing public charging sites. In addition to programmatic and enabling investments, specific delivery system investments will become known when energy resources siting, whether centralized or DERs, begins through established interconnection processes. The readiness of the grid and customers for DER integration will decrease the cost for interconnection and increase the number of viable locations. Substation and circuit improvements may be needed in order to ensure and expand DER effectiveness.

Replacement of the current aging and obsolete Automated Meter Reading (AMR) system and electric customer meters with Advanced Metering Infrastructure (AMI) technology is ongoing, as is replacement of the obsolete Outage Management System with Advanced Distribution Management System (ADMS) technology. These foundations will enable more non-wire solutions in the future.

The ADMS will enable an enhancement to PSE's current Distribution Automation (DA) program. Fault Location Isolation and Service Restoration (FLISR) is a combination of smart field devices controlled by centrally located software that provides self-healing capabilities to key feeders in the system. Over the last few years, PSE has implemented FLISR as a part of its DA program. PSE currently implements DA using a centralized, rules-based approach with a stand-alone software. ADMS will enable a more flexible centralized, model-based approach. This approach is considered more sustainable and flexible than the rules-based approach because it allows the FLISR process to continue operation under different switching configurations. This is especially important as the grid grows more complex, and customer expectations for reliability grow. Finally, FLISR using ADMS will allow PSE to automate circuits that have volt-var optimization implemented.

As DERs become more prevalent, PSE will need to (1) monitor and visualize DERs, and their interactions with the distribution grid (2) control the DERs and (3) dispatch them. To perform these tasks, the PSE operator/dispatcher will need a system that allows them to perform the tasks identified above. The system of record is called DERMS or Distributed Energy Resource Management System.

DERMS is in an early stage of maturity in the industry, so exact capabilities vary across technology vendors. PSE's future DERMS will be integrated with the ADMS to allow full visibility to the system operator and allow for safe and optimal dispatch coordinated with other operations activities.

DERs and transportation electrification are changing load patterns, but not evenly across the system. As a result, system planning practices can no longer be primarily defined by seasonal system peaks, and planners require greater insight to the expected locations of DERs and EVs. PSE is investing in a geospatial load forecasting tool to predict load and power changes, where on the grid the new loads will occur, how distributed generation (DG) changes the load shape, and when DG must be supplied. The tool addresses both short-term circuit trends and long-term grid expansion. The resulting forecast provides system planners with substation, circuit and small-area resolution time-series load growth and load shape changes. This tool will provide key functionality to avoid reactive investments from DER integration and transportation electrification. The geospatial load forecasting tool will utilize GIS, SCADA, and AMI data to perform its analysis.

The pace of DER and utility scale interconnection is expected to grow rapidly over the next several years. PSE is investigating options and requirements for an enhanced web-based interconnection portal that would streamline the interconnection process for customers and developers by prescreening applications. The tool would make use of the geospatial load forecast, hosting capacity analysis and power flow model.

PSE will pursue local programmatic energy efficiency, conservation voltage reduction (CVR), volt-var optimization (VVO) and demand response. The AMI project will allow PSE to more broadly implement the CVR program for circuits fed from approximately 164 substations, which lowers customers' energy use through reduction in supply voltage. When ADMS is fully installed, the CVR program will mature to volt-var optimization which optimally manages system-wide voltage levels and reactive power flow to achieve efficient distribution grid operation. This dynamic voltage management approach will support the integration of intermittent renewables and new transportation electrification loads. VVO uses end-of-line voltage information from AMI meters. PSE will continue to build on its demand response experience using AMI data and modeling tools to help solve projected needs.

AMI will enable customer and operational analytics, customer energy management tools, and new rate structures to incent beneficial usage patterns. While the AMI project is still underway, PSE has identified 38 unique use cases that could be implemented using AMI data. Time-of-use pricing pilots are currently under development. Customer energy management will be promoted by first providing customers with access to their usage data at a greater granularity than available with legacy AMR meters.

In addition to the major electric infrastructure pilots described below, PSE has developed pilot projects involving microgrids and DER integration. Two microgrid pilot projects will allow PSE to test use cases and develop technical capabilities. The Samish Island Community Demonstration will serve a fire station and nearby homes on Samish Island in Skagit County. This project will deploy a front-of-the-meter battery with roof-top solar panels and other smart equipment, switches, and controls. This project will provide an opportunity to test a community battery's ability to manage solar integration, form a microgrid to 'island' the fire station for emergencies, and provide temporary back-up power. The Tenino Microgrid project is partially funded through a Clean Energy Fund Grant from the Washington State Department of Commerce. The primary installation will be an approximately 1MW/2MWh lithium-ion battery at PSE's Blumaer substation and solar array on adjacent land, complementing existing solar panels at nearby Tenino High School. Combined, the system will form a microgrid capable of providing temporary back-up power to the school during an outage. We also plan to install a second battery in the Tenino area to enhance local reliability. The learnings from both microgrid pilots will be used to inform future planning in areas where PSE seeks to provide additional reliability, resiliency and integrate DERs.

Long-range Electric Infrastructure Plans

Summary of Major Electric Projects in Implementation

Figure M-4 summarizes the planned projects in the project implementation phase, which includes design, permitting, construction and close-out.

Figure M-4: Summary of Major Electric Projects in Implementation

SUMMARY OF MAJOR ELECTRIC PROJECTS IN IMPLEMENTATION	EST IN SVC.
1. Sammamish – Juanita New 115 kV Line	2023
2. Eastside 230 kV Transformer Addition and Sammamish-Lakeside-Talbot 115kV Rebuilds (Energize Eastside)	2022
3. Electron Heights – Enumclaw 55-115 kV Conversion	2024
4. Sedro Woolley - Bellingham #4 115 kV Rebuild and Reconductor	2024
5. Bainbridge Island (NWA Pilot)	2024
6. Lynden Substation Rebuild and Install Circuit Breaker (NWA Pilot)	2024

Major Electric Projects in Implementation Phase

1. SAMMAMISH – JUANITA NEW 115 kV LINE [1]

Estimated Date of Operation: 2023

Project Need. Improvements must be made to increase transmission capacity and reliability in the Moorlands area. The existing system serves 56,000 customers in 5 cities from 12 substations with three transmission lines built more than 50 years ago using small wire. PSE's annual transmission system assessment to meet NERC reliability standards indicates multiple contingency (N-1-1) overload issues in the Moorlands area. Both winter and summer seasons are impacted. Interim operating plans have been developed to sectionalize lines and drop load if necessary to prevent overloads and meet NERC requirements, but this reduces customer reliability. PSE Planning Guidelines call for a fourth line when serving a commercial area in which load exceeds 150 MW. Credible outage scenarios could force one of the three lines to serve the entire 12-substation area.

[1] / https://www.pse.com/pages/pse-projects/sammamish-juanita-transmission-line

Solution Implemented. Install 4.65 miles of new 115 kV transmission line, reconductor 0.15 miles of existing 115 kV transmission line between NE 124th St. and Juanita Substation, loop the Totem Lake Substation, and install supervisory control and automatic switching on switches on either side of Crestwood Substation.

Current Status. The project is in design and permitting.

2. EASTSIDE 230 kV TRANSFORMER ADDITION AND SAMMAMISH – LAKESIDE – TALBOT 115 kV REBUILDS (THE ENERGIZE EASTSIDE TRANSMISSION CAPACITY PROJECT)[2],

Estimated Date of Operation: 2022

Project Need. The backbone of the Eastside electrical system has not had a voltage upgrade since the 1960s. Since then, Eastside's population has grown from approximately 50,000 to nearly 400,000, and growth is expected to continue. Currently, electricity is delivered to the area through two 230 kV/115 kV bulk electric substations – Sammamish substation in Redmond and Talbot Hill substation in Renton – and distributed to neighborhood distribution substations using the many 115 kV transmission lines located throughout the area. PSE's annual transmission system assessment to meet NERC reliability standards completed in 2013 and 2015 demonstrated PSE could not meet federal reliability requirements in the area by the winter of 2017/18 and the summer of 2018 without the addition of 230 kV/115 kV transformer capacity. Overloads will impact the reliable delivery of power to PSE customers and communities in and around Redmond, Kirkland, Bellevue, Clyde Hill, Medina, Mercer Island, Newcastle, Renton, and the towns of Yarrow Point, Hunts Point and Beaux Arts among others. The supply issue focuses on the two 230 kV supply injections into central King County at Sammamish substation in the north and Talbot Hill substation in the south. The winter load level was expected to exceed capacity around the winter of 2017-18, and the summer load level was expected to exceed capacity in the summer of 2017. PSE's annual assessment also identified that primary driver of need was the forecasted summer overload. These possible overloads would result in operating conditions that put thousands of Eastside customers at risk of outages.

Solution Implemented. Install a 230 kV/115 kV transformer substation in the center of the Eastside load area and a rebuild of the 115 kV Sammamish – Lakeside – Talbot #1 & #2 lines to 230 kV to provide additional transmission capacity to serve projected load growth.

Current Status. This project is in permitting with approval of the Environmental Impact Statement, and Bellevue Conditional Use Permit (CUP). The Bellevue CUP is currently being appealed.

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2 / https://www.energizeeastside.com

3. ELECTRON HEIGHTS – ENUMCLAW 55-115 kV CONVERSION[3, 4]

Estimated Date of Operation: 2024

Project Need: NERC reliability requirements for multiple contingencies identify this project as needed to prevent transmission system voltage collapse, overloading of the 115-55 kV transformers at Krain Corner, Electron Heights and White River, and overloading of the White River-Krain Corner 55 kV line. The project provides additional 115 kV support at Krain Corner and Electron Heights substations. It also provides the needed 115 kV supply for the new Buckley substation as well as needed improvement to the reliability of both the Electron Heights-Stevenson, and Krain Corner-Stevenson transmission lines through protection improvements and creation of the 115 kV loop.

Solution Implemented: Convert 22 miles of transmission line between Electron Heights and Stevenson substations from 55 kV to 115 kV operation, including the conversion of Wilkeson Substation and construction of a new Buckley 115 kV substation. The 55 kV equipment at Electron Heights Substation will be converted to 115 kV. The transmission line will connect through the Enumclaw Substation creating a complete 115 kV transmission loop from Electron Heights to Krain Corner substations; this will allow for the removal of Stevenson Substation, which will be a great benefit to the local community. One and one-quarter miles of the transmission line will be reconductored, and a short section of new 115 kV line will be built to maintain 55 kV service to the Greenwater Tap.

Current Status: This project is in final design, permitting and property acquisition.

4. SEDRO WOOLLEY – BELLINGHAM #4 115 kV REBUILD AND RECONDUCTOR

Estimated Date of Operation: 2024

Project Need. There are several needs for this project. First, the low-capacity line ratings could cause the line to exceed its allowable ratings for several contingencies and limit generation capacity in Whatcom and Skagit Counties. The small copper wires could also cause high line losses, and the aging infrastructure could lead to extended outages. Second, the low capacity of the Bellingham-Sedro Woolley #4 line has caused constraints on regional power flows for over twenty years due to the parallel higher-voltage transmission line which requires PSE to protect the line from loading above its allowable limits by automatically opening the Sedro Woolley substation circuit breaker. Opening this breaker (and subsequently the line) reduces system reliability in both Whatcom and Skagit Counties, including the Norlum and Alger substations. The 6,240 customers served from the Norlum and Alger substations are at an increased risk of outage

[3] / *https://www.pse.com/pages/pse-projects/electron-heights-enumclaw-transmission-line-and-substation-upgrades*
[4] / *https://www.pse.com/pages/pse-projects/buckley-substation*

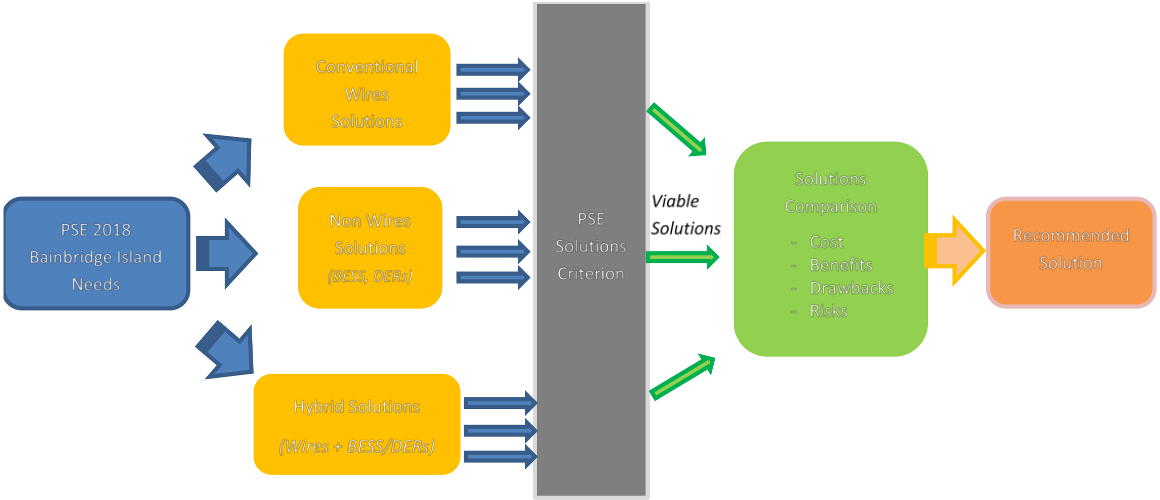
during such time as each substation has only one transmission source. Finally, the line's aged equipment has contributed to 27 momentary outages and four sustained outages in the five years prior.

Solution Implemented. Rebuild and reconductor the existing 24-mile Sedro Woolley-Bellingham #4 115 kV line which connects the Skagit County and Whatcom County 115 kV systems and directly feeds two distribution substations, Alger and Norlum. To coordinate concurrent distribution system upgrades, this project is being constructed in five phases: Phase A includes approximately 4 miles of the line in Skagit County; Phase B includes approximately 7.5 miles of the line in Skagit County; Phase C includes approximately 6 miles of the line in Skagit and Whatcom Counties; Phase D includes approximately 6 miles of the line in Whatcom County; and Phase E rebuilds the final 0.5 miles of the line in Skagit County.

Current Status. This project was initiated in 2010. Phase A was placed in service February 2018; Phase B was placed in service December 2018. Phase C, D and E are in design and permitting.

PSE has selected four areas of future needs to test, enhance and develop the planning process for integrating non-wires solutions: Bainbridge Island, Lynden, Seabeck and Kitsap. Bainbridge Island and Lynden have completed the planning process and are now in the implementation phase of project development. The following project descriptions provide insight into the process, initial findings and challenges in these areas. Seabeck and Kitsap are still in the planning phase and follow in the next section. In each area, PSE performed an electrical system needs assessment and identified key needs for grid investment. Next, solutions criteria for system performance were developed for the key needs. Alternative solutions were considered in three categories: 1) conventional wire solutions, 2) non-wire solutions consisting of battery storage and distributed energy resources (DER), and 3) hybrid solutions involving a combination of wires and non-wires components. Solutions were considered viable if they met all identified system needs and the performance standards set in the solutions criteria. Finally, a solutions alternatives analysis was conducted in order compare the costs for all viable solutions, and a solution was selected based on cost, benefits, drawbacks, risks and benefit-to-cost ratio. A diagram of the solutions process is shown below in Figure M-5.

Figure M-5: Solutions Process Overview



PSE engaged the services of two consulting firms, Navigant and Quanta, to assist in preparing the four non-wire analysis (NWA) and the combined teams worked for well over a year. The Bainbridge and Lynden project analyses are complete. The Seabeck and West Kitsap analyses are under review and identifying solutions that will satisfy the needs assessment for each of the projects.

5. BAINBRIDGE ISLAND (NWA PILOT)[5]

Estimated Date of Operation: 2024

Bainbridge Island transmission and distribution system serves 12,450 customers in Kitsap County from 3 substations and two 115kV transmission lines. The island is served by two parallel transmission lines via one water crossing from Suquamish.

Need Assessment. PSE begins studying an area when certain study triggers occur based on the system health, operations, load growth projections and other information that surfaces. Data is gathered and assumptions are made as followed.

<u>Planning Study Triggers</u>

- Transmission reliability
- Aging infrastructure on the Winslow Tap transmission line
- Load forecasted to exceed 85 percent of substation group capacity in 2019

<u>Data and Assumptions</u>

- PSE's system load forecast net of conservation and known block load additions
- Current substation loading

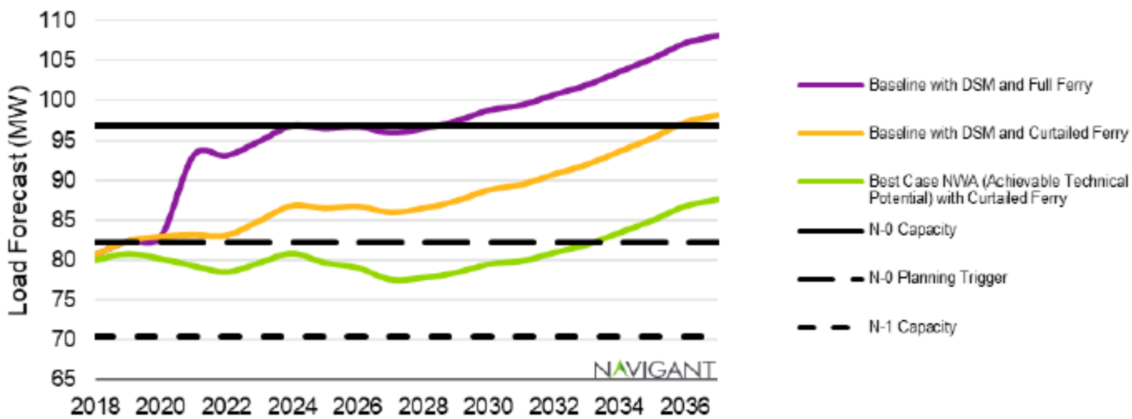
[5] / *https://www.pse.com/pages/pse-projects/bainbridge-island-electrical-system-improvements*

- Outage data from 2013 through 2017

Needs Identified. These include capacity, reliability, aging infrastructure and operational flexibility.

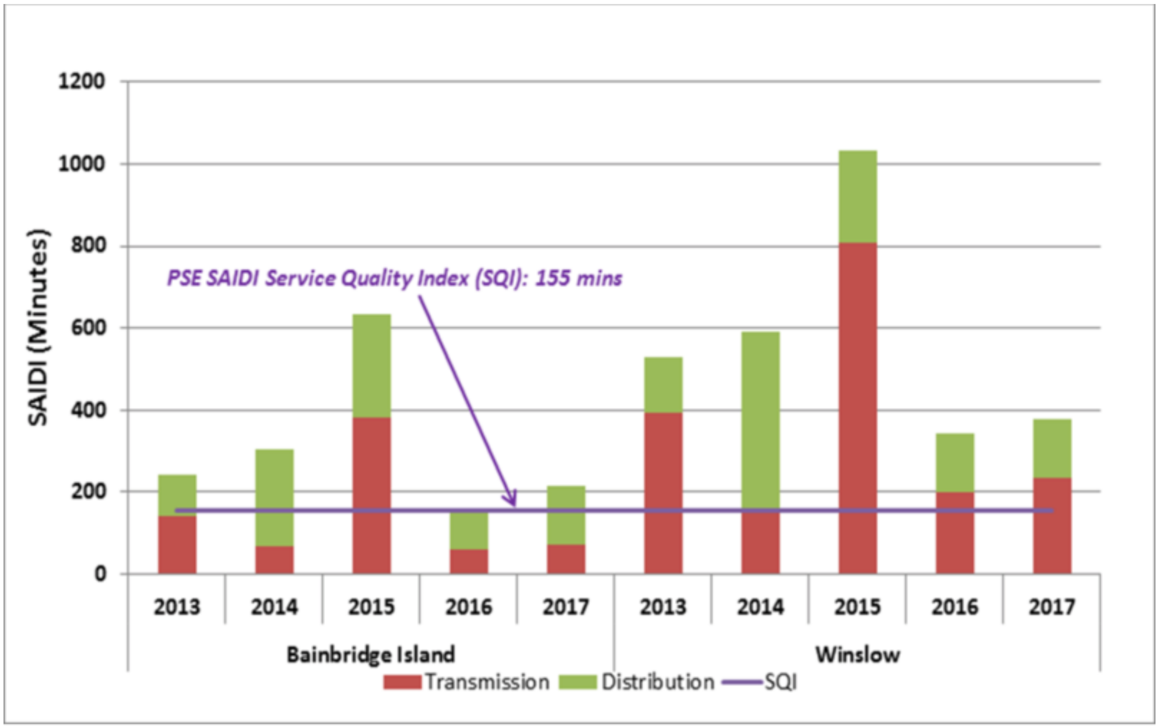
Capacity: Additional capacity will be required to meet projected load growth on the island over the next 10 years and the potential electric ferry charging facility as early as 2021.

Figure M-6: Bainbridge Island Potential Non-wires Forecast Scenarios



Reliability: Performance of the transmission source feeding the Winslow substation needs to be improved. Forty-seven percent of the total customer minutes of interruption to Bainbridge Island between 2013 and 2017 were caused by transmission outages. Nearly 70 percent of the 5-year total customer minutes of interruption were caused by Winslow transmission outages.

Figure M-7: Comparison of Bainbridge Island and Winslow SAIDI Performance



<u>Aging Infrastructure</u>: PSE's 2019 field inspection determined that 50 percent of the Winslow transmission tap wishbone-type crossarms will require replacement in the next one to three years.

<u>Operational Flexibility</u>: There was an operational flexibility concern related to the ability to transfer load to support routine maintenance and outage management. Winslow and Murden Cove substations are on radial transmission taps and have no operating flexibility at the transmission level.

Solution Assessment. Solution criteria includes technical criteria and non-technical criteria as follows.

<u>Technical Criteria</u>

- Must meet normal winter peak load forecast with 100 percent conservation
- Must be ≤ 85 percent of substation group utilization
- Must not re-trigger any of the needs identified in the Needs Assessment for 10 years or more after the project is in service.

<u>Non-technical Criteria</u>

- Feasible permitting
- Reasonable project cost
- Uses proven technology that may be adopted at a system level
- Constructible within reasonable timeframe

<u>Evaluation of Solution Alternatives</u>

PSE conducted a solutions alternatives analysis to determine a cost-effective solution that meets all identified system needs for Bainbridge Island over a planning horizon of ten years (2018-2027). A solution was considered viable if it met all identified system needs and the performance standards set in the solutions criteria.

Alternative solutions were considered in three categories.

1. Conventional wire solutions
2. Non-wire solutions consisting of battery storage and distributed energy resources
3. Hybrid solutions involving a combination of wires and non-wire components

Eight alternatives were evaluated. These included three variations of traditional transmission line and substations alternatives, one alternative using all battery storage to meet need, and five hybrid alternatives. Three alternatives were determined to be viable as a result of the analysis.

PSE concluded that a non-wires-only solution appeared technically feasible but that it would result in a higher cost than the wires solution, a lower benefit cost ratio, involve significant disruption to Bainbridge Island, and likely not be ready in time to meet the projected load of the new electric ferry charging station.

Given these drawbacks, PSE considered potential hybrid solutions that included both conventional wired components and non-wired components. The technical potential and economic analysis concluded that a non-wires portfolio of energy efficiency, energy storage, renewable distributed generation and the option of demand response had the potential to cost-effectively defer the wired alternative of a distribution substation for capacity need until 2030 given current load forecasts. The consultants recommended sizing the energy storage to meet 50 percent of capacity needs in 2030; their analysis indicated that a 3.3 MW/5MWh battery would provide sufficient flexibility for PSE to study and pilot targeted demand response and energy efficiency programs to meet the other 3.3 MW of need before other delivery system measures become absolutely necessary.

Figure M-8: Viable Alternatives for Bainbridge Solution

	Wired Alternative	Non-Wired Alternative	Hybrid Alternative
Solution Overview			
Primary Need: Winslow Tap Transmission Reliability	Transmission Loop	Total BESS: 25.1 MW/79.2 MWh MUR: 13.7 MW/34.8 MWh MUR-14, MUR-15, PMA-13: 7 MW/24.4 MWh WIN-13: 4.4 MW/20 MWh	Transmission Loop
Primary Need: Substation Group Capacity	New Dist. Substation		Ferry Curtailment: 10 MW up to 182 hr. 50% BESS @MUR: 3.3 MW/5 MWh 50% DER: 3.3 MW
Primary Need: Winslow Tap Aging Infrastructure	Replace Aging Poles; Improve Corridor Access and Veg Mgmt; Perfect Rights	Replace Aging Poles; Improve Corridor Access and Veg Mgmt; Perfect Rights	Replace Aging Poles; Improve Corridor Access and Veg Mgmt; Perfect Rights
Decision Factors	- Expertise - Long term solution - No ferry impact - High reliability	- New technology - 10 year solution - Ferry impact - Add with growth - New operations	- New technology - 10 year solution - Ferry impact - Add with growth - New operations - Local EE and DR
Benefit/Cost Ratio * Preliminary and subject to change	3.73	1.82	4.47

The hybrid solution has an estimated baseline cost of $24.3M compared to an estimated baseline cost of $28.7M for the wired solution. The hybrid solution also presents the opportunity to increase learning about adoption of energy storage and distributed energy resources as a method for deferral of electric system needs.

<u>Preferred Solution</u>

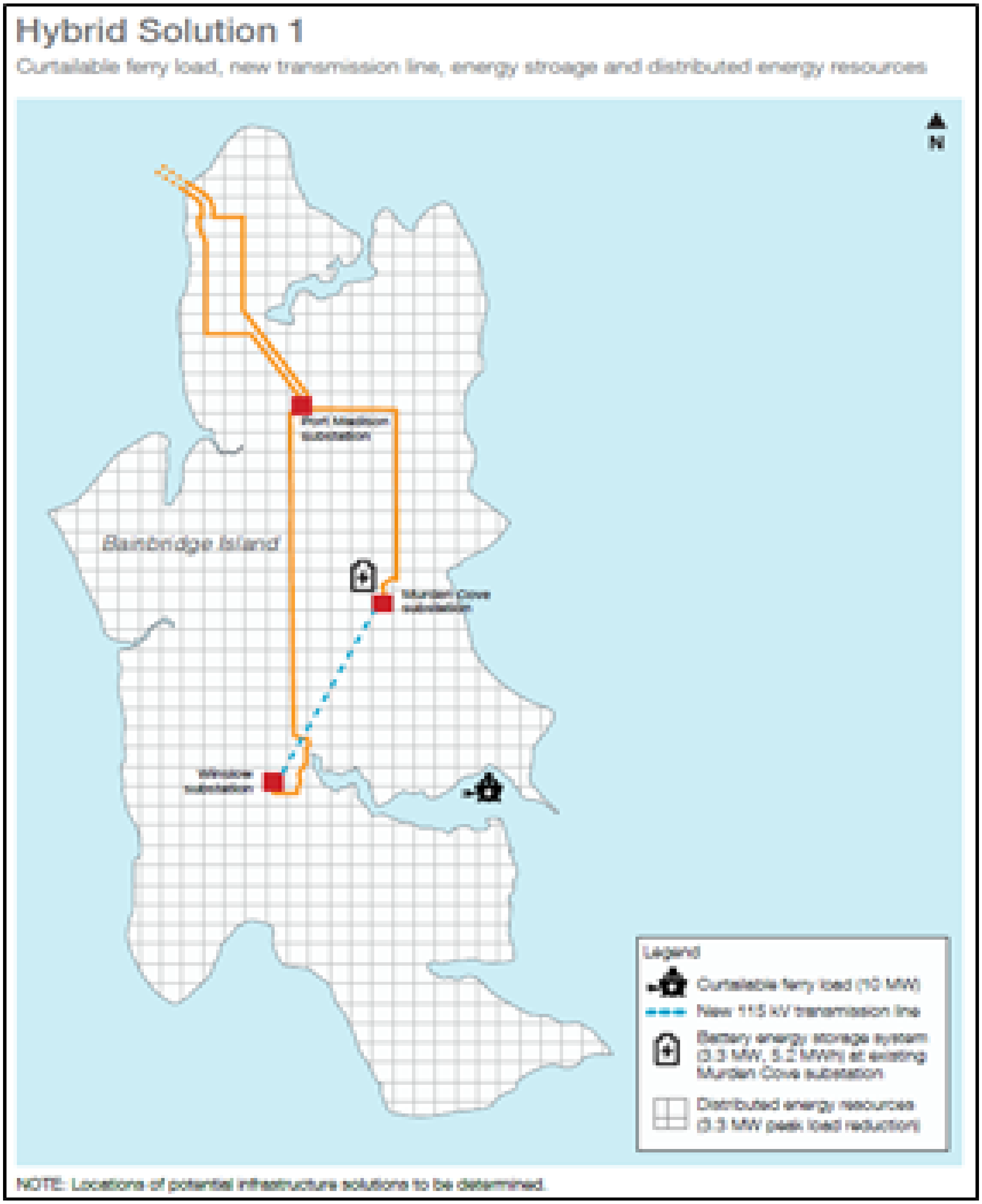
The preferred solution to further evaluate is the hybrid solution using traditional wired investment for the transmission and distribution reliability needs and a combination of energy storage and DERs for the distribution capacity need and reliability improvement.

The primary components of this solution are:

- An approximately 3.3 MW energy portfolio including energy efficiency, renewable distributed generation and the potential for demand response.
- An approximately 3.3 MW/5 MWh battery located at Murden Cove substation.

- 3.5 miles of new overhead 115kV line between Murden Cove and Winslow substations to create a transmission loop.
- Replacement of 50 percent of poles and crossarms and improvement of the corridor for maintainability and operability of the Winslow transmission tap.
- Connection of the 10 MW ferry load as a curtailable resource.

Figure M-9: Bainbridge Island Hybrid Solution



- **Current Status.** This solution is in the development stage with an Energy Storage team and a DER team performing initial scoping strategy.

6. LYNDEN SUBSTATION REBUILD AND INSTALL CIRCUIT BREAKER (NWA PILOT)

Estimated Date of Operation: 2024

The Lynden substation serves 6,300 customers in Whatcom County, PSE's most northern area. The equipment is aging, and due to the site configuration, performing necessary maintenance and repair work is difficult. This in turn limits operational flexibility. One of the substation transformers is nearing end of its life based on the substation's health report and needs replacement by 2021. The existing substation yard and equipment configuration will not support replacement with a standard transformer.

Need Assessment. PSE begins studying an area when certain study triggers occur based on the system health, operations, load growth projections and other information that surfaces. Data is gathered and assumptions are made as followed.

<u>Planning Study Triggers</u>

- Equipment age and condition
- Lack of transmission line circuit breaker
- Possibility of Remedial Action Scheme (RAS)
- Substation operational concerns
- Distribution reliability and operation concerns including capacity triggers

<u>Data and Assumptions</u>

- Assessment horizon – the ten-year period from 2018 to 2027
- Whatcom County local area demand forecast from PSE's F2017 Load Forecast, which estimated average annual demand growth of 0.66% over 10 years.
- Assume the 2018 feeder extension project enables Lynden Circuit 26 to tie to Lynden Circuit 23, thereby enabling some load transfer to delay further feeder capacity upgrades.
- Current substation loading
- Outage data from 2013-2017
- Asset health information from pole inspection data (2019 and previous years)
- Maintenance and operating history
- Power flow analysis consistent with North American Electric Reliability Corporation (NERC) TPL-001-4 requirements
- Assessment is in compliance with PSE's Transmission Planning Guidelines and Distribution Planning Guidelines

Needs Identified. Aging infrastructure, reliability and operational needs exist presently and over the next 10 years. The next substation upgrade is recommended by 2021 for aging equipment replacement and may be needed by 2023 for load growth.

Aging Infrastructure. The Lynden Bank 2 transformer, rated 12/16/20 MVA, 115 -13.09 kV Y-Δ-Y, was installed in 1967. Its 2.0 MVA regulator was manufactured in 1965. A condition assessment of the Bank #2 transformer and regulator was performed by PSE's Technical Field Services (TFS) group in April 2018. The TFS Condition Assessment Report recommended that Bank 2 (XFR0196 and REG0277) be removed from service and replaced with a new LTC transformer within the next three years. PSE's Asset Management Group has planned to replace the transformer by 2026, based on economic life, by which time it would be 59 years old.

Reliability. One of the three transmission lines at the substation does not have a circuit breaker where the line connects to the 115 kV bus. This causes reliability impacts to all 6,300 Lynden Substation customers and risks momentary outages to another 15,700 customers of northern Whatcom County. A fault on this line also triggers a generation Remedial Action Scheme (RAS) at Sumas generating plant, removing 160 MW of generation from PSE's system twice as often as would be required if the transmission line had a circuit breaker. Additionally, during the five-year period from 2013 through 2017, the main contributor to high customer minutes of interruption (CMI) in the Lynden area was a wind storm on August 29, 2015. This storm significantly impacted Whatcom County. All three transmission lines to Lynden were out of service between 12:45 p.m. and 7:46 p.m. Each line had multiple outages during the storm, some of which were restored automatically prior to a permanent fault event.

Figure M-10 : Lynden Transmission Interruptions 2013-2017

CMI TRANSMISSION INTERRUPTIONS, 2013-2017			
Full Line Name	**Line Number**	**Total No. of Faults**	**CMI**
BPA Bellingham - Lynden (115 kV)	77	1	4,470,730
Portal Way – Lynden (115 kV)	264	2	576,928
Sumas – Lynden (115 kV)	167	2	279,162
Sumas – Bellingham (115 kV)	2	9	1,855,415
PSE Average 115 kV Line		4.5	3,071,838

Studies indicate there are areas of potential low voltage (< 113 volts) on LYN circuits that are could occur under N-0 conditions.

Finally, there is one distribution circuit, LYN-14, that is above the system average for CMI with a value of 125,631 minutes (105 percent of system average). The annual CMI reliability performance data for all LYN circuits from 2013 through 2015 is summarized in Figure M-11.

Figure M-11: Annual CMI Reliability Performance Data for 2013-2015

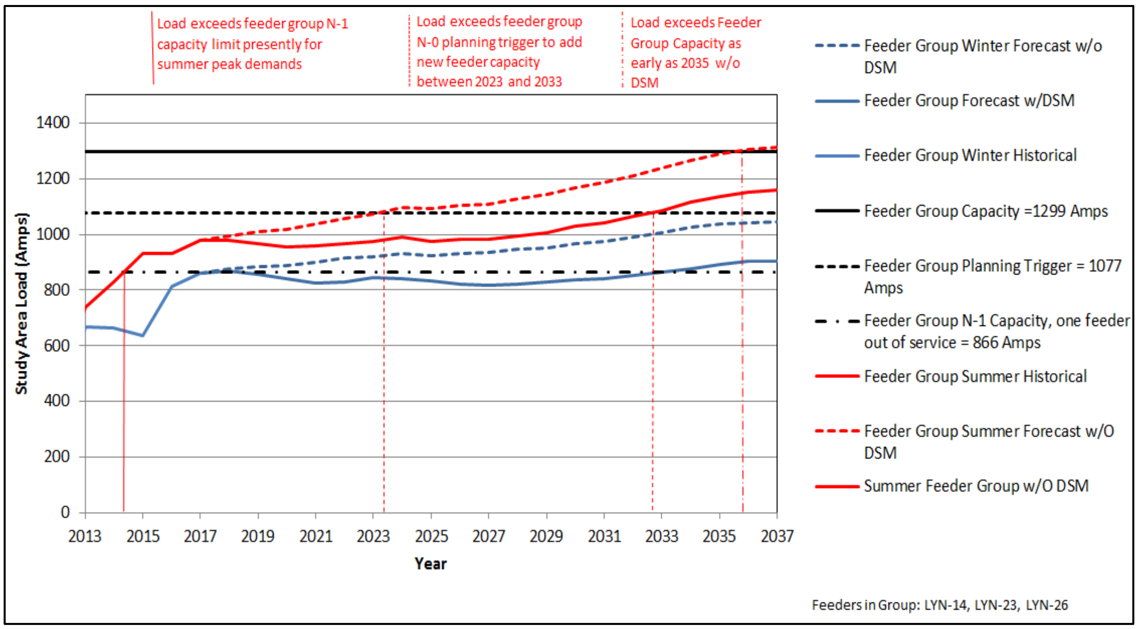
Non-MED CMI (IEEE, T_{MED} adj for catastrophic storm), Minutes				
Circuit	**2013**	**2014**	**2015**	**Average (2013-2015)**
LYN-13	53,774	47,035	13,464	38,091
LYN-14	46,226	325,861	4,806	125,631
LYN-16	787	-	278	355
LYN-17	46,596	47,058	6,352	33,335
LYN-23	219	711	7,657	2,862
LYN-24	27,460	102,883	211,164	113,836
LYN-26	39,556	130,062	27,900	65,839

Operational Flexibility. The existing layout affects reliability, future growth, and the ability to move workers and equipment in the substation to perform work.

- The crowded substation has more equipment than is usually found in a substation of this size, challenging crew ability to work efficiently and safely.
- There is not enough space in the substation for the upgrades required to replace the Bank 2 transformer. These upgrades include improvements to the control house and the Bank 2 feeder structure.
- Substation controls are spread among three control houses and a battery structure, with no room for more control equipment.
- Most double-banked substations have a bus tie switch between feeder structures; however, the Lynden substation does not. Without the bus tie switch, extensive field switching is required when taking a substation transformer out of service. Unplanned bank outages are longer in duration due to multiple distribution switching steps.

Capacity. Load growth within Whatcom County is uneven and Lynden Substation includes only a portion of the county, so the project team developed local load growth forecasts considered reasonable based on historical load growth and known load additions. Figure M-12 illustrates historical and projected demand for the 20-year F2017 load forecast for the LYN-14, 23, 26 Feeder Group. This figure also illustrates the N-1 planning trigger and capacity limits of the station group. Projected demand is shown both with and without adjustment for demand-side measure (DSM) effects. The planning trigger to add N-0 station capacity to this study grouping could be reached in 2037 without DSM.

Figure M-12: Projected Demand for LYN-14, 23, 26 Feeder Group



Solution Assessment. Solution criteria includes technical criteria and non-technical criteria as follows.

Technical Criteria

- Must meet all performance criteria for transmission and distribution.
- Address all relevant PSE equipment violations identified in the Needs Assessment.
- Address all relevant needs identified in the Needs Assessment Report.
- Must cause no adverse impacts to the reliability or operating characteristics of PSE's or surrounding systems.
- Must not re-trigger any of the needs identified in the Needs Assessment for 10 years or more after the project is in service.
- Must not increase non-MED SAIDI and non-MED SAIFI.
- Address key infrastructure impacted by replacements to aging infrastructure.

Non-technical Criteria

- Feasible permitting
- Reasonable project cost
- Uses proven technology that may be adopted at a system level
- Constructible within reasonable timeframe

Evaluation of Solution Alternatives

Determining which parts of Lynden's needs could be met with non-wires components was more complicated than in the other three areas where PSE is piloting non-wires analysis. The interdependent needs presented an opportunity to further develop a framework for the initial assessment of project needs that takes place prior to investigation of non-wires alternatives.

The potential to solve Lynden needs using non-wires alternatives, including a combination of energy efficiency, demand response, solar photovoltaic, and distributed generation was evaluated. PSE concluded that a non-wires-only solution did not appear to be technically feasible. It was determined that critical upgrades needed to meet operational flexibility concerns and transmission reliability could not be solved by a non-wires solution, so any scenario analyzed to solve all of the identified needs would need to be a hybrid solution. In considering the type of needs that might be met with NWAs, Navigant noted that "NWAs are typically developed to address needs that tie directly to capacity constraints, and less typically to address other types of needs." For this reason the team investigated whether any of the needs were connected to capacity constraints. An alternative was considered that would utilize DERs and energy storage to remove rather than replace the aging transformer. This alternative would include critical substation upgrades only and would not include transformer replacement and associated metal clad feeders and substation expansion. Ultimately 6 solutions were considered to solve the needs identified at Lynden.

Figure M-13 shows the traditional wired solutions and hybrid solution that were developed. PSE conducted a solutions alternatives analysis for these alternatives to determine the most cost-effective solution that meets all identified system needs for Lynden over a planning horizon of ten years (2018-2027). The analysis identified Alternative 3 to have the greatest benefit for cost to improve the substation.

Figure M-13: Five Lynden Substation Wires Alternatives
Benefits and Benefit vs. Cost Summary

Lynden Substation Project Benefits													
		Benefits											Cost
Alternative	Description	New Bank #2 Trf	New 115 kV Breaker	Bank #1 Ckt Switcher	Substation Expansion	New Control House	Bank #1 Metalclad	Bank #2 Metalclad	Transformer Differential	Remote 12.5 kV Breaker Control	Improved Driveway Access	12.5 kV Bus Section Switch or Breaker	115 kV Aux Bus or Better	Estimated Cost:
1	Replace Bank #2 in place when required.	✓												N/A
2	Expanded substation with 115 kV Main Bus and 1 Metalclad Feeder	✓	✓	✓	✓	✓		✓		✓	✓	✓		$7-14 million
3	Expanded substation with 115 kV Main Bus and 2 Metalclad Feeders	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		$8-17 million
4	Expanded substation with 115 kV Ring Bus and 2 Metalclad Feeders	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	$12-27 million
5	New substation at new site with 115 kV Ring Bus and 2 Metalclad Feeders	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	$11-43 million
6	Hybrid: Remove transformer, perform DER measures and do reduced scope of work in existing substation fence.	Not Needed	✓	✓	Not Needed	✓	✓	✓	✓	✓		Not Needed		$20-42 million

<u>Preferred Solution</u>

Even though the initial non-wires analysis suggested that there was an opportunity for cost-effective non-wires solution options for Lynden, a more detailed analysis indicated that a non-wires alternative will not be lower net cost than the traditional wires solution. The distinct characteristic of Lynden – a long-duration summer peak – meant that there are few incremental cost-effective DER available in PSE's portfolio that can address this peak. Without much capacity reduction from DER, the solution relies on a large-capacity battery, which is expensive relative to the traditional solution.

A staged approach can be used to make substation improvements efficiently. The preferred solution is for the substation be expanded within four years to address the aging infrastructure and operability issues before they affect customer reliability. At this point, the wired Alternative #3 would expand the substation, install a 115 kV circuit breaker for the BPA Bellingham-Lynden line, consolidate the control houses into one new control house, replace transformer Bank 2, replace both feeder structures to improve function, capacity and reliability, and improve operability by spreading out the equipment and relocating the driveway.

Alternatives will also be considered that would employ "non-wires" features that may be able to avoid some of the investment in traditional infrastructure. The hybrid options being developed would address both the N-0 capacity at the Lynden Substation and the N-1 capacity for the three-substation group that includes Lynden, Berthusen and Hannegan with only one transformer bank installed at the Lynden Substation. This three-substation group tends to achieve peak load in the summer due to agricultural operations in the region, which presents the opportunity to consider solar photovoltaics as part of the hybrid alternative in addition to energy storage and distributed energy resources.

Current Status. This solution is in the final approval stage. Once approved it will move to the implementation phase for detailed design and permitting.

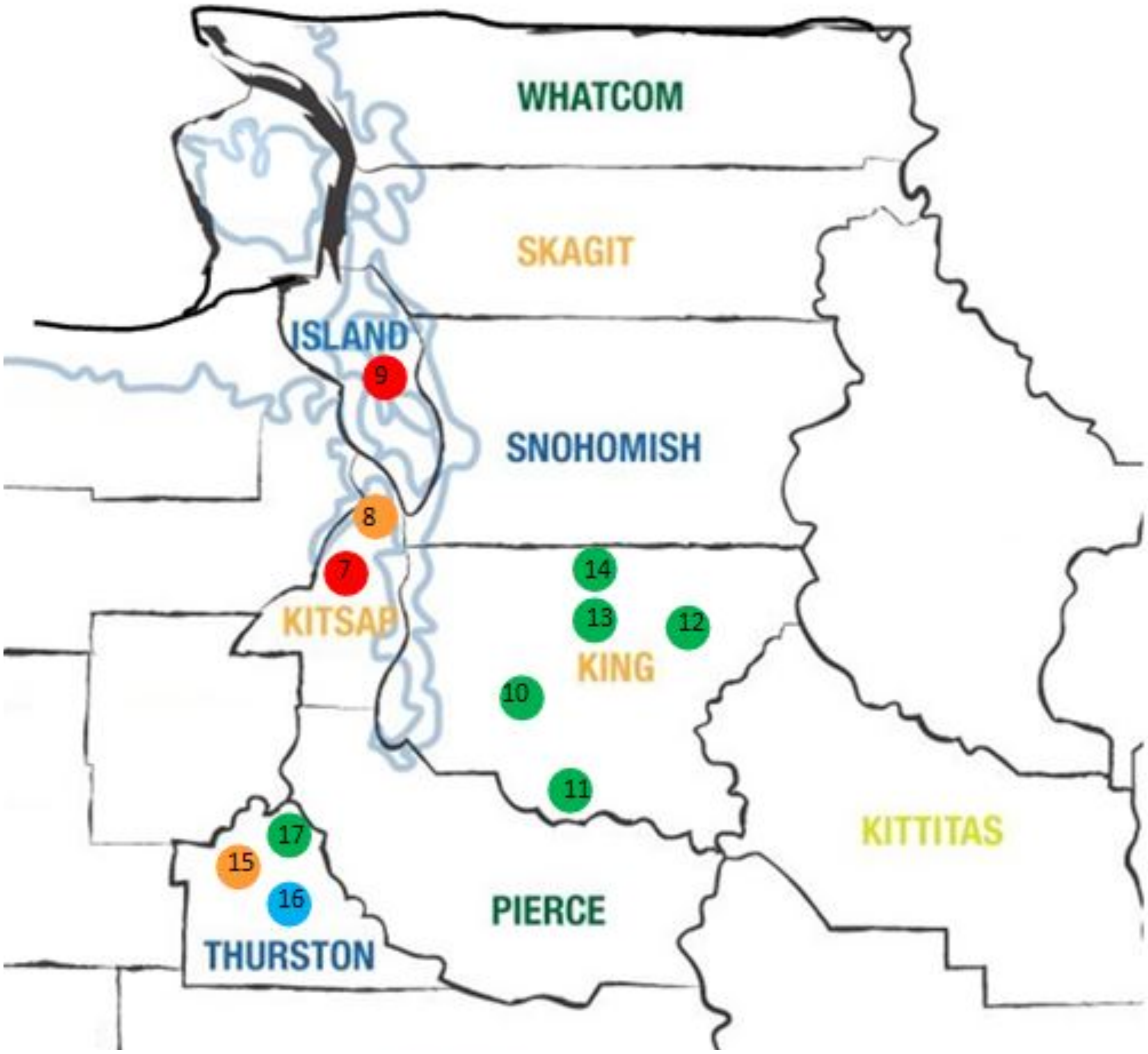
Major Electric Projects in Initiation Phase

The following projects are in the initiation phase which includes determining need, identifying alternatives and proposing and selecting solutions. Included are the remaining two projects being used to test, enhance and develop the planning process for integrating non-wires solutions. Based on learnings from the Bainbridge Island and Lynden assessments, described in the previous section, this process has been initiated on additional projects and a comprehensive study plan has been created to address known system needs going forward using the same approach.

Figure M-14: Summary of 10-Year Major Electric Initiation Projects

SUMMARY OF MAJOR ELECTRIC PROJECTS IN INITIATION	DATE NEEDED	NEED DRIVER
7. Seabeck (NWA Pilot)	Existing	Reliability
8. West Kitsap Transmission Project (NWA Pilot)	Existing	Stability, Transmission Capacity & Aging Infrastructure
9. Whidbey Island Transmission Improvements	Existing	Reliability
10. Kent / Tukwila New Substation	2020	Capacity
11. Black Diamond Area New Substation	2020	Capacity
12. Issaquah Area New Substation	Existing	Capacity
13. Bellevue Area New Substation	2021	Capacity
14. Inglewood – Juanita Capacity Project	2024	Capacity
15. Spurgeon Creek Transmission Substation Development (Phase 2)	Existing	Stability & Capacity
16. Electron Heights - Yelm Transmission Project	2024	Aging Infrastructure
17. Lacey Hawks Prairie	2021	Capacity

Figure M-15: Electric Planned Projects in Planning Phase



7. SEABECK

Estimated Need Date: Existing Need

Date Need Identified: 2019

Seabeck area in Kitsap County serves 4,700 customers from two feeders through two substations and two transmission lines.

Need Assessment. PSE begins studying an area when certain study triggers occur based on the system health, operations, load growth projections and other information that surfaces. Data is gathered and assumptions are made as followed.

Planning study triggers

- Feeder Capacity - The loads in an area reach approximately 83 percent of existing capacity for both overhead (OH) and underground (UG) feeder sections under N-0 system operating conditions.
- Substation Capacity - The loads in an area reach approximately 85 percent of existing station capacity for a study group of three stations or more to maintain operational flexibility.

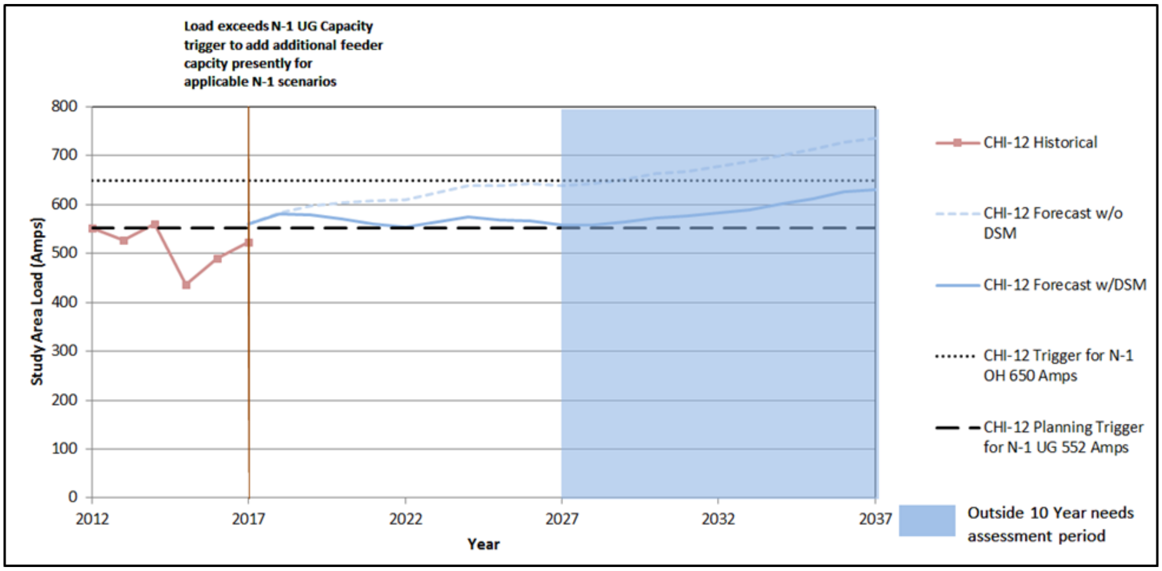
Data and Assumptions

- The assessment horizon selected was the ten year period from 2018 through 2037.
- Historical five-year outage data are used in the assessment.
- There are no PSE DER's (distributed energy resources) on the feeders.
- There is 134 kW of interconnected net metering generation capacity on Chico substation on feeders CHI-12 79 kW, CHI-13 32 kW, CHI-15 5 kW, CHI-16 18 kW.
- There is 248 kW of interconnected net metering generation capacity on Silverdale substation on feeders SIL-13 73 kW, SIL-15 106 kW, SIL-16 69 kW.
- Normal Winter F2018 load forecast with 100 percent conservation

Needs Identified. The needs drivers identified are capacity and reliability.

Capacity: There are feeder capacity needs for distribution circuits CHI-12 and SIL-15. Both circuits are above the Distribution Planning Guidelines of 83 percent utilization of capacity under normal system configuration for current peak loading levels. CHI-12 is over 100 percent utilization under the contingent loading event of a step-up transformer failure for current peak loading levels. Figure M-16 illustrates historical demand, projected demand, and the N-1 anticipated capacity need during the 10-year study period for CHI-12.

Figure M-16: CHI-12 N-1 Feeder Loading and Capacity



Feeder circuit CHI-12 has also experienced large phase imbalances at system peak during the past five years that are greater than planning guidelines allow (100 amps between any two phases). In 2017, at system peak, the difference between A and B phases was above 100 Amps for 60 hours with a peak imbalance of 124 Amps imbalance: Phase A averaged 657 Amps, B averaged 443 Amps and C averaged 401 Amps. In early January 2017, some single phase laterals were transferred from phase A to C. 2017 hourly PI data showed a maximum of 126 Amps imbalance between A and C. The resulting 126 Amp imbalance is above planning criteria of 100 Amps.

<u>Reliability</u>: There are also reliability concerns with circuits CHI-12 and SIL-15. Both are on PSE's worst-performing circuit list. These two circuits serve the entire load in this area and continue to have SAIDI and SAIFI scores significantly worse than average.

- Reduction of 220,000 CMI is needed on CHI-12 after completion of planned Distribution Automation (DA) project CMI Performance (2013-2015). The primary driver for CHI-12 is the 3 year non-MED CMI greater than 3 million minutes.
- Figure M-17 illustrates the CMI reliability metric for the Seabeck area which shows for both circuits well more than an average of 500,000 CMI minutes per year which is an indicator of poor performance.

Figure M-17: Seabeck Area Reliability Performance

Non-MED CMI (IEEE, T_{MED} adj for catastrophic storm), Minutes				
Circuit	**2013**	**2014**	**2015**	**Total (2013-2015)**
CHI-12	390,482	4,647,138	2,183,190	7,220,810
SIL-15	553,718	505,098	2,104,432	3,163,248

Solution Assessment. Solution criteria includes technical criteria and non-technical criteria as follows. PSE developed solutions criteria for system performance in the areas of capacity, reliability, asset life and constructability.

Technical Criteria

- Must meet normal Winter F2018 load forecast with 100 percent conservation
- Must meet distribution planning standards and guidelines
- Must result in ≤ 100 percent of individual substation utilization
- Must result in ≤ 100 percent of overhead individual feeder limits for N-0 and applicable N-1 scenarios
- Must result in ≤ 100 percent of underground individual feeder limits for N-0 and applicable N-1 scenarios
- Must address all relevant PSE equipment violations
- Must not cause adverse impacts to the reliability or operating characteristics of PSE's or surrounding systems.
- Must meet performance criteria for 10 years or more after construction

Non-technical Criteria

- Environmentally acceptable to PSE and the communities it serves
- Constructible by the winter of 2021.
- Utilize proven technology that can be controlled and operated using existing systems

Evaluation of Solution Alternatives

PSE studied conventional wires alternatives and determined the top wires alternatives to include (as shown in Figure M-18):

- WA-1: Build a new 115kV-12kV distribution substation near Seabeck
- WA-2: Build a new 35kV-12kV distribution substation near Seabeck
- WA-3: Install a third parallel step-up transformer at Chico substation
- WA-4: Install a new express feeder from Chico substation to segment the existing feeder

Figure M-18: Four Seabeck Wires Alternatives

		WA-1 Scope	WA-2 Scope	WA-3 Scope	WA-4 Scope
Needs	CHI-12 N-1 Capacity	Solved through new substation	New 35kV Substation	Third Parallel step up transformer	New CHI-14 Circuit taking
	CHI-12 Distribution Feeder Reliability	Improved through transmission restoration priority and spreading customers to multiple feeders	Improved through sub transmission restoration priority and spreading customers to multiple feeders	Improved through protection to multiple sub feeders. Mainline is hardened with tree wire	Improved through express underground feeder and creating sub feeders. Some customers transferred to new circuit
	SIL-15 Distribution Feeder Reliability	Improves SIL-15 CMI by placing some customers on a new circuit	Improves SIL-15 CMI by placing some customers on a new circuit	Does not reduce SIL-15 CMI	Improves SIL-15 CMI by placing some customers on new circuit
	Low Voltage	Solved through shorter feeders and more balanced circuits	Solved through LTC at new 35kV substation and sub placed closer to load center	Solved through addition of regulators and reduced load imbalance	Solved through reduction of load on CHI-12 and SIL-15 and reduced load imbalance
	CHI-12 Phase Balance	Phase imbalance will reduced to less than 100 Amps per feeder. More opportunities to balance load.	Phase imbalance will be reduced to less than 100 Amps per feeder. More opportunities to balance load.	Phase balancing will need to be performed	Phase imbalance will be reduced to less than 100 Amps per feeder. More opportunities to balance load.
Decision Factors	Additional Costs - Land (ROW, Property)	Sub. property available, Public ROW	Public ROW	Public ROW	Public ROW + CHI-14 getaway route, New Step-Up Transformer Location
	Total Baseline Cost Estimate	$29.8 M	$19.5M	$12.5 M	$11.3M
	Reliability Benefits	High	Moderate	Moderate	High
	Benefits	Highest reliability improvement, eliminates most 35kV, increases operational flexibility	Improves reliability, increases operational flexibility	Improves reliability, increases operational flexibility	Improves reliability, eliminates 35kV exposure, increases operational flexibility
	Drawbacks	High Cost	High Cost	35 KV remains, no improvement to SIL-15 CMI	Some 35kV remains
	Risks	Public opposition to new substation and T-Line	Public opposition to new substation	Permitting Challenges	Permitting Challenges
	B/C Ratio	1.22	2.02	2.36	3.27
	Overall Preference	Lowest due to cost	3rd	2nd	1st Highest B/C ratio

After PSE developed conventional wires alternatives, Navigant was contracted to review these alternatives, analyze non-wire alternatives (NWA), and analyze hybrid solutions consisting of both wires and non-wires alternatives. The goal of their analyses was to consider the technical and economic feasibility of potential alternatives that could meet the Seabeck area needs. It was found that phase balancing would be best addressed using conventional methods, so a non-wires solution was not feasible. A hybrid solution composed of both wires and non-wires elements is a cost-effective and technically feasible solution. Ultimately two solutions were considered, a wired solution and a hybrid solution, as outlined in Figure M-19 below. As noted in the table, the non-wires solution did not meet the needs of the area.

Figure M-19: Three Seabeck Solution Alternatives

		Top Wires Alternative	Top Non-Wires Alternative	Top Hybrid Alternative
Needs	CHI-12 N-1 Capacity	Solved through new Feeder	Solved through Energy Storage and DER	Solved through Energy Storage and DER
	Distribution Feeder Reliability	Improved by reduced tree/vegetation outage exposure and allowing more effective automation, while reducing the number of customers exposed to each outage	Distribution Reliability is not addressed in the full non-wire alternative	Improved by reduced tree/vegetation outage exposure and allowing more effective automation
	CHI-12 Phase Balance	Phase imbalance will be spread throughout feeders reducing to less than 100 Amps per feeder. More opportunities to balance load.	Phase Balance is not addressed in full non-wires alternative	Phase imbalance will be spread throughout feeders reducing to less than 100 Amps per feeder. More opportunities to balance load.
	Low Voltage	Reduced loading and express 35kV circuit solves low voltage areas	Reduced loading solves voltage issues	Reduced loading and UG conversion solves voltage issues
Decision Factors	Total Cost Estimate Range (Base to High)	$11.3 million to $14 million	$4.6 million to $6.5 million	$16.1 million to $19.6 million
	Benefits	10 year solution. Highest reliability benefit. Added capacity. Increased operational flexibility	10 year solution. Local EE and DR	10 year solution. Improved reliability[6]. Local EE and DR
	Risks	Easement and Permitting challenges for new construction	No Reliability improvement. Easement and Permitting challenges for BESS site. New operational strategies needed. Need additional improvements with growth	Easement and Permitting challenges for BESS site. New operational strategies needed. Need additional improvements with growth

Current Status. PSE is performing a cost comparison for all viable solutions. The preferred solution will be selected based on cost, benefits, drawbacks, risks and benefit-to-cost ratio.

[6] *Navigant has identified islanding as a potential additional reliability benefit of the Hybrid Alternative, however this would require additional studies and operational changes within PSE.*

8. WEST KITSAP TRANSMISSION IMPROVEMENT (NWA PILOT)

Estimated Need Date: Existing Need

Date Need Identified: 2018

The West Kitsap area includes Port Orchard, Bremerton, Poulsbo and Bainbridge Island and serves 122,000 customers from 28 substations and 18 transmission lines.

Need Assessment. PSE begins studying an area when certain study triggers occur based on the system health, operations, load growth projections and other information that surfaces. Data is gathered and assumptions are made as followed.

Planning Study Triggers

- Capacity need
- Voltage collapse conditions
- Transmission reliability
- Aging infrastructure

Data and Assumptions

- The study analyzed the Kitsap Peninsula transmission system over a planning horizon of 10 years (2018 to 2027).
- The 2017 PSE Load Forecast was utilized to project native PSE load in Kitsap County – with 100 percent conservation.
- There are two non-PSE major loads on the Kitsap Peninsula – U.S. Naval Base Kitsap and the U.S. Navy Puget Sound Naval Shipyard (PSNS). The load levels for these two non-PSE major loads were taken from the WECC power flow models.
- The transmission system assessment was conducted in accordance with the NERC and WECC Transmission Planning Standards (TPL-001-4, TPL-001-WECC-CRT-3) and PSE Transmission Planning Guidelines.
- Transmission contingency studies were focused on the BPA transmission supply system out of BPA's Shelton substation and PSE's transmission facilities located within Kitsap County.
- Generation dispatch patterns and Northern Intertie transfers were maintained the same as in the WECC base cases, as they have no significant impact on the Kitsap Peninsula transmission system.
- There are no utility-scale generation resources within Kitsap County. There are distributed energy resources connected behind the meter, and those are included in the loads.
- There are no transportation loads for PSE in Kitsap County; however, the study model includes transportation loads in other counties. The power flow base cases modeled PSE

transportation load as observed during 2017, i.e., summer transportation load of 238 MW and winter transportation load of 262 MW.

Needs Identified. The analysis determined that there are capacity, thermal and voltage needs over the next 10 years on the transmission system, plus operating flexibility, aging infrastructure and reliability concerns.

Capacity. The existing 230 kV supply system to Kitsap Peninsula lacks capacity under multiple contingency scenarios (N-1-1, N-2 or bus contingencies) in supplying the forecasted Kitsap Peninsula load over the 10-year planning horizon (2018-2027). Certain multiple contingencies result in a voltage collapse on the peninsula. In 2018, eight 115 kV transmission lines located in central and northern Kitsap Peninsula exceeded their emergency limits for N-1-1 conditions during the winter and summer peak conditions.

Operating Flexibility. The 115 kV transmission system on Kitsap Peninsula is capacity constrained under N-1-1 scenarios during winter. This creates operating flexibility concerns while scheduling outages for planned and unplanned maintenance on the transmission system during winter. Typical corrective action to prevent N-1-1 overloads includes opening the transmission network to make transmission lines radial, which reduces reliability and increases the risk of the transmission outages.

Aging Infrastructure. BPA’s two 230 kV bulk transformers feeding PSE’s Kitsap Peninsula load are nearing the end of their useful life at 40 and 56 years of age. Loss of a bulk transformer and the long timeframe required to replace it with a spare (approximately a month) puts PSE’s Kitsap load at risk of a large outage or voltage collapse for the next major contingency during peak winter conditions. PSE’s 115 kV Vashon submarine cables are 56 years of age and have had numerous operational issues.

Solution Assessment. Solution criteria includes technical criteria and non-technical criteria as follows. PSE developed solutions criteria for system performance in the areas of capacity, reliability, asset life and constructability.

<u>Technical Criteria</u>

- Must meet all performance criteria for Transmission and Distribution
- Must address all relevant PSE equipment violations identified in the Needs Assessment
- Must address all relevant needs identified in the Needs Assessment Report
- Must not cause any adverse impacts to the reliability or operating characteristics of PSE's or surrounding systems
- Must not re-trigger any of the needs identified in the Needs Assessment for 10 years or more after the project is in service

<u>Non-technical Criteria</u>

- Environmentally acceptable to PSE and the communities it serves
- Constructible by the winter of 2029
- Utilize proven technology which can be controlled and operated using existing systems
- Reasonable project cost

<u>Evaluation of Solution Alternatives</u>

PSE planners is developing multiple wires solutions to solve the area's needs for use to compare with non-wires solutions comprised of distributed energy resources and utility-scale energy storage systems. At this time, one of the wired alternatives has been to use as a reference for the non-wires analysis. Additional wired alternatives are being developed, and a final proposed solution is yet to be determined.

The Kitsap Peninsula needs are so great that the peninsula load would need to be reduced by more than 30 percent in the near term to reduce all N-1-1 thermal overload and voltage collapse conditions. As a result, an energy storage system comparable to the largest ever built would be required to entirely eliminate the need for a conventional wires solution. In addition, the non-wires expert consultants on the project team estimated that a full non-wires alternative would be many times more expensive than the wires solution. Once it was determined that a full non-wires solution was not practical technically or economically, hybrid solutions were considered.

The wired components considered in the hybrid solutions varied slightly, but consistently included the bulk system elements necessary to prevent voltage collapse. Energy storage and distributed energy resources were analyzed for their ability to prevent overloads. To meet portions of the capacity needs, alternatives including exclusively energy storage or combinations of energy storage and distributed energy resources were considered. However, while there is some potential to reduce the size of the energy storage for hybrid solutions (compared to a full non-wires solution), the net costs are still much higher than the estimated conventional solution costs. There are many winter hours that exceed the capacity threshold, and these longer duration needs are more expensive to meet with battery storage or distributed energy.

Preferred Solution: The preferred solution is to continue development of a full wires solution. Given the complexity of the wires solutions, work will continue on refining the preferred solution developed initially that involves the installation of multiple segments of 115 kV transmission lines between BPA Kitsap/South Bremerton and Valley Junction. The final step of the multi-year plan is to add a 230-115 kV transformer capacity in Kitsap County. The non-wires studies prepared for PSE by the consultants will be referenced as the wires solution is finalized, but at this time the overall conclusion is not expected to shift materially. Deconstructing the needs and potential solutions for a complex transmission system with significant needs required a very high level of effort by the project team (both PSE staff and the consultants), and the experience provided PSE with a sense of the demanding analysis required and the feasibility of meeting such transmission needs with non-wires alternatives.

Current Status. Completion of the alternatives analysis is expected by Q1 of 2021. Stakeholder engagement will be determined after the recommended solution becomes available.

9. WHIDBEY ISLAND TRANSMISISON IMPROVEMENTS

Estimated Need Date: Existing

Date need identified: 2018

Whidbey Island serves 38,000 customers out of 12 substations and two transmission lines.

Project Need. The need drivers for this area are aging infrastructure, reliability, capacity and operational concerns.

Aging Infrastructure: Replacement of aging infrastructure is an immediate need. Two 115 kV oil-filled circuit breakers need to be replaced at Whidbey Substation due to age and outdated technology. The distribution transformer at Faber Substation was installed in 1968 and is being monitored due to the presence of water in the oil. Plans are under way to replace this transformer with a 25 MVA load tap changing transformer in the future.

Reliability: The main bus design at Whidbey Substation does not allow for breaker maintenance without a line outage and has a possibility of outage of substations south of Whidbey due to a bus or breaker fault.

Capacity: A capacity concern beginning in 2026 includes transmission line ratings that are significantly limited due to low ratings of the older circuit breaker CT's.

Operational Concerns: There are over and under voltage concerns outside the standard range of 116 V – 126 V on certain sections of the feeders on the Island.

Current status: The needs assessment has been completed and the study process for both traditional wires solutions and non-wire alternatives will be undertaken in 2021.

10. KENT/TUKWILA NEW SUBSTATION

Estimated Need Date: 2020
Date need identified: 2018

The Kent-Tukwila area serves 20,300 customers from 12 substations and four 115 kV transmission lines. The area is expected to experience heavy growth in the next 20 years.

Project Need. The need drivers for this area are capacity and aging infrastructure.

<u>Capacity</u>: 2018 NERC TPL studies showed that different combinations of P6 contingencies (N-1-1) resulted in the potential for thermal overloads during summer and winter peak conditions starting in 2024. Additional development occurring in the area (including redevelopment of industrial areas) has resulted in the need for additional substation and distribution system capacity to serve growing demand. The additional loads also exacerbate the NERC Compliance issues listed above.

<u>Aging Infrastructure</u>: Replacement of aging infrastructure is an immediate need. The 115 kV underground transmission line that provides transmission service in the area was installed in 1974 and is currently beyond its expected service lifetime. Loss of transmission support from the cable would negatively impact reliable service to customers in the area.

Current status: The study process for traditional solutions is underway. The study has not progressed enough to propose solutions. Project initiation to review alternatives is expected to be finalized in 2021.

11. BLACK DIAMOND AREA NEW SUBSTATION

Estimated Need Date: 2020
Date Need Identified: 2019

The Covington/Black Diamond area serves 17,500 customers from six substations and one 115 kV transmission line. The area is expected to experience heavy load growth in the next 20 years.

Project Need. The need drivers for this area are capacity and reliability.

Capacity: Several large developments in the area will result in the need for additional distribution capacity. This capacity will need to come from additional transmission substations in order to serve the load reliably and meet the future needs.

Reliability**:** A single 115 kV transmission line serves this area. The transmission system will need additional reinforcements to ensure that reliability is not reduced if additional substations and distribution transformers are added to the existing equipment.

Current status. The study process for traditional solutions is underway. The study has not progressed enough to propose solutions. Project initiation for review of alternatives is expected to be finalized in 2021.

12. ISSAQUAH AREA NEW SUBSTATION

Estimated Need Date: 2021
Date Need Identified: 2019

The Issaquah area distribution feeders serve 23,000 customers in downtown Issaquah, Klahanie and the Highlands area from four substations with four transmission lines. The area is expected to experience more growth in the near future.

Project Need. The need driver for this area is capacity.

Capacity. Between 2020 and 2021, the predicted load increases will reduce operational flexibility for the feeder group in the Issaquah Highlands area and exceed the planning trigger for adding additional feeder capacity. Between 2023 and 2025, the area will have insufficient feeder capacity to serve additional load. In 2018, with the operating scenario of having one feeder out of service (N-1), capacity was already exceeded. This has resulted in lengthier outages, as the ability to pick up customers during a feeder outage contingency is limited.

Current status. Preferred wires solution are expected to be identified at end of 2020. The two expected options are expanding Pickering substation to two banks (requires an additional transmission line) or interconnect a new 230 kV at Grandridge site to BPA. The traditional solutions should be identified by end of 2020 and non-wires solutions by the end of March 2021. Then project initiation will be able to review the alternatives.

13. BELLEVUE AREA NEW SUBSTATION

Estimated Need Date: 2021
Date Need Identified: 2018

The downtown Bellevue, Redmond and Kirkland area serves 21,000 customers from 8 substations and three 115 kV transmission lines. The area is expected to experience more growth in the near future.

Project Need. The need drivers for this project are reliability and distribution capacity.

Reliability: Bellevue and Kirkland have a high percentage of commercial, industrial and high-rise residential customers in the downtown core. For a planned outage followed by an unplanned outage during peak summer or winter loading on either of these lines, a significant amount of residential and commercial load will be at risk.

Capacity**:** Load growth from the new Sound Transit and Spring District exceeds the capacity of the distribution system.

Current Status. The detailed Needs Assessment is complete. The study process for traditional solutions will start in 2020. Traditional solutions should be identified by the end of March 2021 and non-wires solutions by the end of June 2021. At that time, project initiation will be able to review the alternatives.

14. INGLEWOOD – JUANITA CAPACITY PROJECT

Estimated Need Date: 2024
Date Need Identified: 2019

With the completion of the Sammamish – Juanita project (Project 1 in the Planned Projects discussion above), the Inglewood – Juanita line will be one of three transmission lines that serves 40,000 customers from eight substations in the Kirkland, Kenmore and Bothell areas.

Project Need. The need drivers for this area are capacity and reliability.

Capacity: 2018 NERC TPL studies indicate thermal overloads for P6 contingencies (N-1-1) during the summer 2024 time period. The same overload is predicted during both the winter and summer 2028 time period.

Reliability**:** The potential increased load along with the potential for additional distribution transformation and capacity requires transmission infrastructure upgrades to maintain reliability for customers.

Current Status. Project initiation to review alternatives is expected in 2022.

15. SPURGEON CREEK TRANSMISSION SUBSTATION DEVELOPMENT (PHASE 2)

Estimated Need Date: Existing Need
Date Need Identified: 2019

The Thurston County South region is primarily served by one Extra High Voltage source and one 115 kV transmission line connecting to the Pierce County grid. The cities of Tenino and Yelm, which are in the South region, have approximately 19,000 customers served by five substations and two transmission line sources.

Project Need. The need drivers for this area are capacity and reliability.

<u>Capacity</u>: A transmission capacity need currently exists under certain N-1-1 transmission contingencies that result in thermal overloads of the bulk power supply source into the Olympia area. A distribution capacity need may also be present at a substation due to estimated load growth, and an additional distribution transformer bank will require the transmission line to be looped into the radially fed substation, providing a second source to the station.

<u>Reliability</u>: Two reliability improvements are required: 1) a new bulk power source supply into South Thurston County, and 2) additional transmission lines to interconnect the North and South regions of Thurston County.

Current Status: The detailed Needs Assessment is underway. The transmission and distribution needs are identified. The study process for traditional solutions will start in 2021. Project initiation to review alternatives expected 2021.

16. ELECTRON HEIGHTS - YELM TRANSMISSION (NEW)

Estimated Need Date: 2024
Date Need Identified: 2019

The Tenino/Yelm area serves approximately 19,000 customers from five substations and two transmission sources.

Project Need. The need drivers for this area are capacity, reliability and aging infrastructure.

<u>Capacity</u>. Greater transmission capacity is needed to resolve line overloads on the Electron Heights-Yelm 115 kV line and low voltage conditions under multiple contingencies (N-1-1) in the area. A significant portion of the line is 4/0 Cu low-capacity conductor, which limits the throughput of the line.

Reliability. The customer is at risk of outages under N-1-1 conditions. The need will be met by the Electron Heights – Enumclaw 55-115 kV Conversion that is expected to be complete in 2022, which may delay the need for this project past the 10-year planning horizon.

Aging Infrastructure. The wishbone cross-arm construction has reached the end of its useful life and poses an outage risk due to failure.

Current Status. The detailed Needs Assessment and Project initiation to review alternatives is expected to start in 2022.

17. LACEY HAWKS PRAIRIE CAPACITY

Estimated Need Date: 2022
Date Need Identified: 2018

The Lacey Hawks Prairie area serves approximately 13,000 customers from three substations and 6 transmission sources.

Project Need. The need driver for this area is capacity

Capacity. Greater distribution substation and feeder capacity is needed to maintain operational flexibility and serve developing load.

Reliability. The customer base is at risk of outages under N-1-1 conditions.

Current status. The detailed Needs Assessment and Project initiation to review alternatives is expected to start in 2021.

3. NATURAL GAS DELIVERY SYSTEM

Existing Natural Gas Delivery System

NOTE: An update of this section will be included in the final IRP.

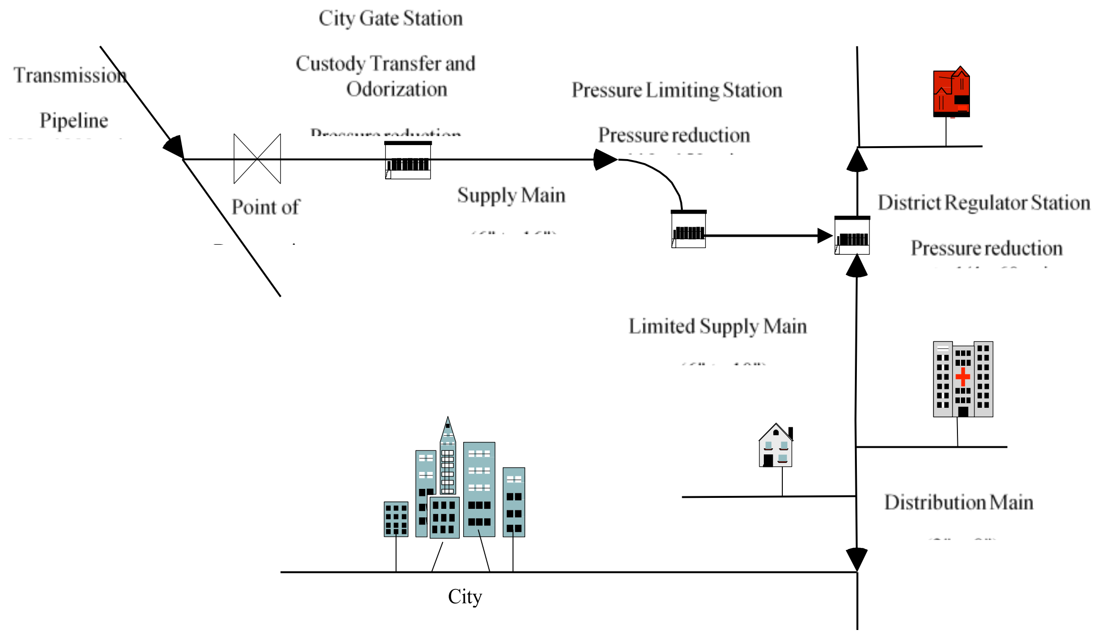
The table below summarizes PSE's existing gas delivery infrastructure as of December 31, 2018. Gas delivery is accomplished by means of pipes and pressure regulating stations.

Figure M-20: PSE-owned Gas Distribution System as of December 31, 2018

GAS
Customers: 837,112
Service area: 2,800 square miles
City gate stations: 42
Pressure regulating stations: 577
Miles of pipeline: 13,154
Supply system pressure: 150–550 psig
Distribution pipeline pressure: 45–60 psig
Customer meter pressure: 0.25 psig

How the Natural Gas Delivery System Works

Figure M-21: Illustration of Gas Delivery System



Natural gas is transported at a variety of pressures through pipes of various sizes. Interstate transmission pipelines deliver gas under high pressures (generally 450 to 1,000 pounds per square inch gauge [psig]) to city gate stations. City gate stations reduce pressure to between 150 and 450 psig for travel through supply main pipelines. Then district regulator stations reduce pressure to less than 60 psig. From this point gas flows through a network of piping (mains and services) to a meter assembly at the customer's site where pressure is reduced to what is appropriate for the operation of the customer's equipment (0.25 psig for a stove or furnace), and the gas is metered to determine how much is used.

The gas system was first built in the late 1800s, expanding in a networked, two-way flow design. Pipeline materials and operating pressures have changed over time. Natural gas was introduced to the Puget Sound region in 1956, allowing for higher pressures and smaller diameter pipes. Where older cast iron pipe was used, new plastic pipe is inserted into it as a way of cost effectively renewing existing infrastructure in urban areas. While the energy qualities and pipeline materials have changed, the technology used to operate the system has not. Because gas pipelines are often located within increasingly congested rights-of-way, protecting pipelines from damage is even more important.

10-year Natural Gas Infrastructure Plan Summary

NOTE: An update of this section will be included in the final IRP.

Figure M-22 summarizes the ten-year gas infrastructure plan that will be further discussed in this section. The additions described below in general terms are intended to indicate the scope of investment that may be required over the next ten years to serve our customers reliably and fulfill regulatory requirements.

Figure M-22: Summary of 10-year Natural Gas Infrastructure Plan

ASSET	NUMBER
New High Pressure Main	38 miles
New Intermediate Pressure Main	36 miles
Gate or Limit Station Upgrades	5
District Regulation	26
Gas Main Replaced	200-300 miles

Short-range Natural Gas Infrastructure Plans (1 to 3 years)

PSE will continue to focus on objectives that include maintaining customer and public safety, gas pipeline integrity and pursuing operational excellence and continuous improvements to meet customer expectations. PSE is committed to considering all project alternatives that meet the needs criteria and optimizing the planning process to improve our alternative analysis.

PSE plans to build or upgrade approximately five Northwest Pipeline-supplied gate or limit stations and 26 district regulator stations to serve load as existing station capacity is exceeded. This work will be on-going in the short range and will continue through 10 years. PSE expects to add approximately 38 miles of high pressure main and 36 miles of intermediate pressure main as loads grow in our service area. As with the electric system, PSE is continually addressing aging gas infrastructure within the system in accordance with regulatory requirements and operating practices. In the next decade, PSE plans to replace 200 to 300 miles of gas main that is reaching the end of its useful life. As mentioned above, PSE anticipates replacing its current aging gas customer modules with Advanced Metering Infrastructure (AMI) technology to enable smart grid enhancements and future customer offerings.

PSE will pursue evaluation of local programmatic targeted energy efficiency combined with demand response options. In 2018-2019, PSE piloted a gas demand response program to determine the potential for peak capacity reductions using smart thermostats. These pilot results will allow PSE to evaluate the potential for gas demand response including non-pipes alternatives and delays in supply and distribution investments. PSE will continue to build on its demand response experience to help determine what role this new tool can play in alternatives to pipeline infrastructure.

Long-range Natural Gas Infrastructure Plans

Summary of Major Natural Gas Projects in Implementation Phase

Figure M-23: Summary of 10-year Major Natural Gas Implementation Projects

SUMMARY OF GAS PROJECTS IN IMPLEMENTATION	DATE NEEDED	NEED DRIVER
1. Bonney Lake Reinforcement Phases 2, 3, & 4	Existing	Capacity & Reliability
2. North Lacey Reinforcement Phases 2 & 3	Existing	Capacity & Reliability
3. Tolt Pipeline Phase 2	2023	Capacity & Reliability

Major Natural Gas Projects in Implementation Phase

1. BONNEY LAKE REINFORCEMENT (PHASES 2, 3 and 4)

Estimated Need Date: Existing
Date Need Identified: 2019

The Bonney Lake area includes the Lake Tapps and South Prairie areas and a particularly large and growing customer development.

Project Need. Demand on PSE's natural gas supply system serving the Lake Tapps and Bonney Lake areas exceeded its capacity in 2017. Additionally, there is a large development being built in the southern end of the system, the Tehaleh development. The combination of existing demand, projected area growth and this new development exceeds the capacity of the existing high pressure lateral. For several years, PSE's ten-year plans have documented the necessary system improvements for the Bonney Lake area. PSE performs manual adjustments in two locations during cold weather along with 100 percent curtailments in order to maintain service at the end of the system. These actions will soon be insufficient to address the reliability concerns.

Figure M-24: Bonney Lake Area Capacity Need

Year Number	Winter Year Need	Total Additional Capacity Necessary in scfh (Cumulative)*	Yearly Capacity Increase (or decrease) Necessary in scfh*
1	2019-20	104,200	104,200
2	2020-21	139,900	35,700
3	2021-22	171,100	31,200
5	2023-24	234,100	63,000
10	2028-29	406,900	172,800
15	2033-34	571,500	164,600
20	2038-39	732,400	160,900

Solution Implemented. PSE is installing 12-inch high pressure pipeline parallel to the existing 6-inch high pressure pipeline for which capacity has been exceeded and a Gate Station to reinforce the natural gas supply to the Bonney Lake and Lake Tapps areas.

Current Status. Phase 1 was completed in 2017, which included two miles of 12-inch line parallel to the existing 6-inch line. Phase 2 will be completed in 2021, which includes an additional two miles of new 12-inch line parallel to the existing 6-inch line. Phase 3 will be completed in 2023, which includes a new gate station.

2. NORTH LACEY REINFORCEMENT (PHASES 2 and 3)

Estimated Need Date: Existing
Date Need Identified: 2009

The North Lacey area includes Lacey and the north and east Olympia areas and serves approximately 21,000 customers. The project is intended to reinforce the Olympia system.

Project Need. Overall customer growth is increasing the demand on the existing system. The supply system needs reinforcement in order to serve recent and projected customer loads. The models are showing significant low pressure issues when pipeline restrictions are taken into account. The supply system is unable to meet minimum design requirements without manual operations. The downstream distribution system cannot maintain adequate system reliability when the upstream supply system is unable to maintain system reliability itself. Two CWAs are scheduled for this area along with 100 percent curtailments, and these actions will soon be insufficient to address the reliability concerns.

Solution Implemented. The preferred solution is a pipeline solution for the current and near-term need. It includes high pressure pipeline and may also include a limit station and a pressure increase. These projects will solve the capacity, pressure, CWA and reliability concerns and still allow for future expansion when and if it occurs.

Current Status. Final completion of the long-term alternatives analysis is expected to be completed by the end of 2019.

3. TOLT PIPELINE (PHASE 2)

Estimated Need Date: 2023

Date Need Identified: 2009

The greater Eastside area, from Bothell/Woodinville to Bellevue in King and Snohomish counties serves approximately 80,000 customers from the Duvall Gate Station.

Project Need. Growth will exceed the current Duvall gate station capacity in the winter of 2022-23, at which time a total station rebuild of Duvall GS is required. The Duvall Lateral, which delivers gas from the Williams Interstate Pipeline at the Duvall Gate Station to the Woodinville, Bothell, Kenmore and Kirkland areas, will experience low pressures for 40 percent of its length during extreme cold weather events. On a design day, the area experiences a shortfall of 127,000 scfh.

Solution Implemented. Install 1.3 miles of 16-inch high pressure pipeline and a new gate station to loop and reinforce the existing supply system.

Current Status. PSE completed Phase 1 of this project, installing 2.7 miles of 16-inch high pressure pipeline in 2015. Phase 2 will be completed in 2026, which includes a new gate station.

Summary of Major Natural Gas Projects in Initiation Phase

Figure M-25 summarizes the planned projects in the project initiation phase which includes determining need, identifying alternatives and proposing and selecting solutions.

Figure M-25: Summary of 10-year Major Natural Gas Initiation Projects

SUMMARY OF GAS PROJECTS IN INITIATION	DATE NEEDED	NEED DRIVER
4. Sno-King Reinforcement Projects	Existing	Capacity & Reliability
5. Gas Reliability Marine Crossing	Existing	Reliability

Major Natural Gas Projects in Initiation Phase

4. SNO-KING REINFORCEMENT PROJECTS

Estimated Need Date: Existing

Date Need Identified: To be provided in final IRP

The Sno-King area includes the south Snohomish county area and the Central/Northern King county areas. This area includes approximately 200,000 gas customers at present.

Need Assessment. PSE begins studying an area when certain study triggers occur that affect system reliability including critical gas pipeline pressures and flows, load/customer growth projections, gas supply contracts, excessive cold weather actions (CWAs), customer curtailments and other information that surfaces. Data is gathered and assumptions are made as follows.

Planning Study Triggers

- Minimum pressure guidelines have been crossed
- Maximum flow guidelines have been reached
- Load and customer growth
- Gas supply contracts with Northwest Pipeline
- Increased CWAs and curtailments
- Gas customer outages

Data and Assumptions

- This study analyzed the Southern Snohomish county area and the Central/Northern King county areas over a planning horizon of 10 years during multiple timeframes, and has extended this timeframe to 25+ years multiple times to ensure solutions were also optimized for the long term.

- Individual load growth of specific areas was completed in detail where needed for these studies. This includes the review of over 5,000 building permits in the Seattle area to help determine commercial gas load growth in this area in the next five years.
- The latest PSE load forecasts were coordinated with detailed planner knowledge of localized growth to determine the final yearly predicted load growth.
- The latest PSE gas models were used that contain all pipes down to the service level and the latest gas load files. Gas loads are calculated for every gas customer on our system based on their history and then this is temperature-compensated and applied to the models.
- All models are baselined against actual flows, loads and pressures to ensure accuracy.
- The loads in the model contain no interruptible loads for these studies.

Needs Identified. The analysis determined that there are operational reliability concerns created by the combination of contract pipeline supply shortfalls, significant capacity concerns due to load growth areas, reliability concerns due to low pressure issues, operational flexibility concerns due to limitations (excessive CWAs/curtailments) and aging infrastructure concerns.

<u>Contract pipeline shortfalls</u>. Significant current contract pipeline shortfalls have the potential to cause widespread gas outages if past historical temperatures and conditions occur.

<u>Capacity</u>. Some of the fastest growing zip codes are contained in the Sno-King area, which are contributing to very significant load growth over many years. Both the supply and distribution systems need reinforcement in order to serve recently added and projected customer loads.

<u>Reliability</u>. The models are showing significant low pressure areas when pipeline restrictions are taken into account. The supply system is unable to meet minimum design requirements without manual operations (see “operational limitations” below). The downstream supply and distribution systems cannot maintain adequate system pressures when the upstream supply system is unable to maintain its system pressure

<u>Operational Flexibility</u>. Six CWAs are scheduled for this area along with 100 percent curtailments, and these actions are markedly insufficient to address the reliability concerns. Manual operations carry an inherent operational risk that an action may not be able to be implemented when needed due to weather and road conditions and/or equipment and personnel issues. There are limitations to manual operations based on location and availability of sufficient equipment and trained personnel. As demand continues to increase, manual operations are insufficient to support the system.

Aging infrastructure: Critical pieces of the pipeline infrastructure have maintenance concerns in addition to a need to be increased in size for capacity reasons. Both of these issues contribute to reliability concerns.

Solution Assessment. Solution criteria includes technical criteria and non-technical criteria as follows that must be met. PSE developed solutions criteria for system performance in the areas of capacity, reliability, cost and constructability.

Technical Criteria

- Must meet all performance criteria for supply and distribution system requirements, including reliability
- Must address all relevant needs identified in the Needs Assessment Report
- Must not cause any adverse impacts to the reliability or operating characteristics of PSE's system.
- Must be able to meet a 25 year planning horizon – staging (phased approach) is acceptable
- Must be safe

Non-technical Criteria

- Meet environmentally impacts and permitting requirements
- Constructible to meet capacity need dates, both current and future
- Utilize proven/mature technology
- Reasonable, prudent project costs
- Must assess and account for community and transportation impacts

Evaluation of Solution Alternatives. PSE and a third-party consultant are completing a thorough alternative analysis that includes analyzing pipeline and non-pipeline solutions (including LNG, CNG, RNG, energy efficiency and demand response).

Preferred Solution. The preferred solution is a pipeline solution for the current and near-term need. It includes a Northwest Pipeline Capacity Increase project that solves the current contract supply concerns, future North Seattle pipeline capacity/aging infrastructure projects, and multiple limit stations and pressure increase projects. These projects will solve the current capacity, pressure, CWA and reliability concerns and still allow for future expansion when and if it occurs. The third-party consultant is analyzing non-pipes solutions, and the future stages/phases of this project will be re-evaluated closer to their need dates.

Current Status. Final completion of the long-term alternatives analysis is expected to be completed by the end of 2021. Construction is completed on the Northwest Pipeline contractual reliability project.

5. GAS RELIABILITY MARINE CROSSING [this is an update for the 2021 IRP]

Estimated Need Date: Current
Date Need Identified: 2019

The marine crossing in King County serves roughly 13,000 customers on the Gig Harbor peninsula and Vashon/Maury Island.

Project Need. The dynamic marine environment in which this crossing has operated for more than 50 years has resulted in the need for reinforcement or replacement of parallel 8” undersea high pressure laterals. Seafloor movement and fatigue induced by ocean currents have resulted in the crossing nearing end of service life.

Reliability. The existing marine crossing is the only pipeline supply of natural gas to roughly 13,000 customers on the Gig Harbor peninsula and Vashon/Maury Island. While the supply is augmented by PSE’s Gig Harbor LNG facility to meet system peak loads, a pipeline connection is required to maintain natural gas service to all customers in the area.

Current Status. Project initiation to review alternative solutions has begun and is expected to be completed in 2021. Limited system modifications are planned in 2021 to enable operation of an emergency backup supply plan should the marine crossing experience a failure prior to completion of the project.