EXH. JBK-1T
DOCKETS UE-220066/UG-220067
2022 PSE GENERAL RATE CASE
WITNESS: JOSH B. KEELING

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, Respondent.	Docket UE-220066 Docket UG-220067

PREFILED RESPONSE TESTIMONY (NONCONFIDENTIAL) OF

JOSH B. KEELING

ON BEHALF OF NW ENERGY COALITION, FRONT AND CENTERED, AND SIERRA CLUB

JULY 14, 2022

NW ENERGY COALITION, FRONT AND CENTERED, AND SIERRA CLUB

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LIST OF EXHIBITS

INTRODUCTION

Q. Please state your name, job title, employer, and business address.

A. My name is Josh B. Keeling. I am the Director at the Cadeo Group, where I lead our Distributed Energy Resources ("DER") and Electrification team. My business address is 107 SE Washington Street, Suite 450, Portland, Oregon 97214.

Q. Please describe your professional background and experience.

A. I have spent over a decade in the energy industry focused on DER integration and planning. At Cadeo, I lead our DER and Electrification team and its work in helping clients develop strategies and plans to more cost effectively enable distributed resources and decarbonize the economy.

I have overseen analysis and provided technical support on a range of topics related to DER interconnection and integrated distribution system planning. Recent examples relevant to this case include:

- Leading the interconnection and controls/communications working groups for a collaborative paper developed between DER aggregators and electric utilities on joint recommendations for state implementation of FERC Order 2222.
- Developing a technical paper for the Energy Systems Integration Group on the current state of DER integration into operations and recommendations for future improvements across the areas such as interconnection, planning, operations, and tariff development.
- Providing technical support to intervening parties in California's Rule 21 interconnection rulemaking, conducting analysis on the expected distribution grid impacts of zero export interconnections.

- Providing technical support and participation in Maryland's Interconnection and Distribution System Planning working groups on behalf of the Office of People's Counsel.
- Supporting the development of the New Buildings Institute's proposed updates to the International Energy Conservation Code for grid interactive technologies.

Prior to Cadeo, I led product management at LO3 Energy, where we helped to enable aggregated DER to provide greater value to utilities, retailers, and their customers. This included the development of distributed solar programs for clients in Europe, Australia, Japan, and the US, including Green Mountain Power and Ameren Utilities.

Prior to LO3, I worked at Portland General Electric ("PGE") for five years, where I led Customer Energy Solutions and established their Distribution Resource Planning group. At PGE, I led the planning and development of their customer resource programs, including dynamic pricing, demand response, energy storage, and transportation electrification programs. This included integration of programs into their integrated resource planning process to address summer and winter capacity needs created by the retirement of PGE's only wholly owned coal plant. The demand response programs my team developed at PGE were recognized in several forums, including winning several awards from the Peak Load Management Alliance. I oversaw PGE's deployment of several pilot distributed energy resource management systems (DERMS), was a technical lead for PGE's deployment of a new customer information system (CIS) and meter data management system (MDMS), was the customer data lead for PGE's cyber security working group, and was the DER lead for PGE's procurement and subsequent deployment of its advanced distribution management system (ADMS).

Puget Sound Energy ("PSE") makes ample use of research developed and lessons learned during my time at PGE. For instance, PSE's market potential study for demand-side resources incorporates assumptions from a demand response potential study I managed at PGE.[1] Additionally, the time-varying rate pilots PSE developed in collaboration with Brattle rely heavily on lessons learned from the pricing pilots that my team and I launched in my time at PGE and evaluated in part by Brattle.

I serve on the board of Grid Forward and am a voting member of the Northwest Power and Conservation Council's Regional Technical Forum, an active contributor to the Advanced Water Heating Initiative, and faculty for the Rocky Mountain Institute's eLab Accelerator program.

My resume is included as Exh. JBK-2.

Q. Have you testified previously before the Washington Utilities and Transportation Commission ("Commission" or "UTC")?

A. No, I have not.

Q. What is the purpose of your testimony?

A. To discuss the appropriateness of targets, forecasts, and anticipated costs related to DER, electrification, and grid modernization investments that PSE is proposing within its Clean Energy Implementation Plan ("CEIP") and its General Rate Case. Specifically, my testimony addresses:

1. PSE's proposed grid modernization and DER enablement investments;

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[1] https://assets.ctfassets.net/416ywc1laqmd/6QdFgc6CNVt3OWTIOxdTZ1/c6e32ad0f6773375c67169f07fd2a4a6/2016-02-01-demand-response-market-research.pdf

2. PSE's proposed demand response targets and programs, including time varying rates; and

3. PSE's proposed electrification and gas decarbonization plans and investments.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the NW Energy Coalition ("NWEC"), Front and Centered, and the Sierra Club, appearing in this proceeding as the "Joint Environmental Advocates."

Q. Please provide a high-level summary of your findings and conclusions from PSE's General Rate Case filing.

A. While I appreciate the breadth and detail provided by PSE in this filing, I find it lacking in many respects. PSE unfortunately manages to provide only modest goals on the highest impact investments, such as demand response and building decarbonization, while showing relatively high costs. PSE is requesting $310 million in incremental rate recovery from electric customers and $143 million from gas customers and yet shows very little progress on electrification, gas decarbonization, DERs, or flexible loads.

Some key conclusions from my review of PSE's initial filing include:

Grid Modernization and Distributed Energy Resources:

- PSE erroneously treats comprehensive grid modernization as a prerequisite to any full-scale deployment of DERs, electrification, or resilience programs. Grid modernization, when thoughtfully planned and integrated, is a critical foundation for the utility of the future. However, there are many examples of utilities in the United States and abroad that have successfully enabled very large penetration of DERs without the tools PSE proposes here, so I disagree that all of PSE's proposed grid modernization capital expenditures are necessary or attributable to CETA. Moreover, rolling out grid modernization is an iterative process that should be driven by current and anticipated needs. PSE claims that its proposed investments in grid modernization here are driven by policy objectives, while neglecting how far behind its peers PSE currently is. For instance, while PSE argues that enabling technologies like SCADA or operational analytics across its full distribution system is driven by CETA, in reality, it is merely PSE catching up to best practice for a utility of its size. Additionally, PSE proposes to jump from fundamental investments, such as AMI and SCADA, directly to cutting edge technologies such as Distributed Energy Resource Management Systems (DERMS), Virtual Power Plants (VPPs), and microgrids. It's hard to imagine how that transition could happen so quickly when there has been so little progress to date. While I'm supportive of fundamental investments, I would advise caution in approving so much capital expense for investments that appear to be so decoupled from actual outcomes, such as increased DER adoption, electrification, resilience, reliability, and/or cost reductions.

Demand Response and Time Varying Rates:

- Despite years of pageantry and process, PSE still fails to demonstrate a sincere effort on demand response commensurate with its regional peers and the industry as a whole. PSE has set a target of 23.7 MW of demand response across a portfolio of programs. This target is so small that it could potentially be met with a single industrial customer in some service territories. PSE has rightly argued in the past that lack of maturity in the NW market and having a winter peaking system make it harder to acquire DR in the region. However, this argument is more difficult to accept after over 10 years of DR program growth amongst its peer utilities and recent findings from the 2021 Northwest Power Plan and the Bonneville Power Administration ("BPA") that show an abundance of cost-effective winter DR in the region (Exh. JBK-4). PSE's own DER RFP showed 160 MW of Tier 1 demand response available today, even with the conservative economics put forward by the utility. Especially with an IRP stating increased capacity needs and their gas decarbonization study raising the specter of even greater peaks in the future (driven by growth in highly controllable loads like space and water heating), PSE needs to quickly acquire dramatically more DR to meet its carbon goals cost-effectively, especially when it is requesting so much capital for grid modernization and enablement.

- Even time-varying rates, which were identified both by the UTC and in PSE's own research as one of the highest value use cases for AMI, are not planned to be fully deployed until 2027. In 2022, when other major investor-owned utilities in the region, like PacifiCorp and Portland General Electric ("PGE"), already have time-varying rates offered at scale and California has them rolled out on an opt-out basis across their residential customers, PSE should not be requesting nearly five years to pilot opt-in program designs that are widely in use around the country. The need for evaluation is of course important, but the incremental value of a slightly more effective experimental design should not be used as an excuse to dramatically delay achieving value from AMI and helping to lower the costs of decarbonization. PSE should be deploying these programs to the broader population now, with low-income customer protections and a commitment to evaluate and adjust their design as necessary on an ongoing basis (as is common practice for DSM programs today). If PSE would like to conduct more experimental pilots, these should be reserved for more innovative or risky designs, such as real-time rates, demand charges, or opt-out TOU/PTR offerings.

Electrification and gas decarbonization:

- PSE eschews the need to electrify buildings, instead insisting on only partial electrification of buildings, claiming that increased electric winter peaks will be too costly to manage. However, PSE makes this claim while not considering modern heat pump technologies, learning curves for heat pump technologies, increasing natural gas prices, synergies with weatherization programs and building codes, use of thermal or electric storage onsite, or co-deployment of resources with flexible load benefits (e.g., demand response) with electrification measures. Doing so presupposes a program design approach out of step with best practices and seems to take a biased view of where technology costs will improve, assuming electrolyzers and renewable methane production will become more cost-efficient while heat pump costs will stagnate. This approach leads to findings that are inconsistent with the growing consensus in the deep decarbonization literature in the Northwest and nationally that recognizes that full building electrification is one of the most critical tools for decarbonization of the energy sector, while also improving public health outcomes and decreasing energy burden. Electrification should be included as part of a comprehensive strategy to manage flexible load, providing opportunities for synergies with weatherization programs and building codes, energy storage, and co-deployment of demand response measures with electrification measures.

- PSE's gas decarbonization efforts show merit in improving lifecycle emissions by blending renewable natural gas and, to a lesser extent, hydrogen, into existing pipelines. These gas decarbonization investments, covered through both voluntary programs and broad-based ratepayer funded programs, are key elements to help PSE meet its decarbonization goals. However, by PSE's own admission, these investments are expected to grow exorbitantly expensive at higher quantities and remain largely unproven at the level of scale suggested in the exhibits sponsored by PSE witness Joshua Jacobs. If PSE is serious about decarbonizing this portion of its business, it should put forward a more comprehensive plan that incorporates integrated distribution planning and asset management, to answer key questions such as what types of fuels can be injected on which parts of the grid and where can PSE strategically prune its distribution networks using electrification.

Q. What are your recommendations on PSE's General Rate Case filing?

A. Based on my review and analysis of PSE's proposed investments in DERs and electrification, I recommend the following:

Grid modernization investments:

- The following grid modernization investments should have no portion attributed to CETA, because the company has not demonstrated that they are specifically related to CETA requirements, instead of simply bringing the utility in line with best practices:
    - Hosting Capacity Analysis ($9.62m attributed to CETA);
    - Data Lake and Analytics ($3.65m attributed to CETA);

    - Substation SCADA – Accelerated ($41.36m attributed to CETA).
- Further, the Circuit Enablement-DER and Microgrid investment of $57.5m should be removed from the revenue requirement request in this proceeding and discussed at a later date, through either the CEIP proceeding or another forum. The company has not made a compelling case for the need for this substantial investment, explained how the company would select circuits for investment, and/or explained how this project would differ from upgrades typically incurred through customer interconnection costs.
- PSE should not be allowed to recover costs for its $9 million proposed investment in VPP without substantially higher targets for demand response and demonstrated reasonable progress toward achieving those targets.

Demand response and time varying rates:

- PSE should be required to acquire at least 160 MW of demand response, with offerings to all customer segments, including large commercial and industrial.
- PSE should be required to adjust its plan for deploying dynamic rates such that all residential and small commercial customers are eligible to participate at the onset. This should include a revised budget, detailed justification for any changes to capital expenditures, and a revised evaluation, monitoring and verification (EM&V) plan.

Electrification and gas decarbonization:

- PSE should integrate transportation costs into future Energy Burden Analyses to ensure a more complete picture of how it can affect customer vulnerability to different energy costs.
- PSE should update its gas decarbonization analysis to include:
    - Revised gas price forecasts incorporating new structural volatility;

- Integration of accompanying EE and DR into deployment of electric end uses;
- Incorporation of heat pump learning curves for standard and cold climate heat pumps;
- Assumptions around naturally occurring air conditioning growth driven by customer preference and increasing summer temperatures;
- Exploration of options that include integration of distributed thermal and/or electric storage with electrification;
- Identification of cost savings for avoided and/or decommissioned gas distribution infrastructure.

- PSE should incorporate findings from its revised gas decarbonization study to develop a building electrification plan. This plan should propose a series of electrification measures that can be co-deployed with its energy efficiency, demand response, and DER programs to achieve cost-effective decarbonization of its gas system.
- PSE should commit to review its gas heating incentives in consultation with its advisory groups in light of new compliance obligations for its gas business. This review should include consideration of replacing gas heating incentives with HP incentives (or at a minimum, deny incentives to gas furnaces that are installed with AC instead of HP) and work to transform the market as their own analysis indicates this is a highly effective way to decarbonize their gas system and it contributes to electric efficiency.
- PSE should explicitly integrate forecasts of building electrification into their load forecasts and revenue requirements analysis for both their gas and electric customers.
- PSE should adjust the Peak Load Management PIM to be assessed on ELCC of demand response achieved, not simply coincident winter peaking value.

- PSE should commit to discouraging the deployment of standalone air conditioning with their contractors and require any incentivized installations of HVAC equipment to use heat pumps for cooling to ensure consistency with its stated goals around electrification.

Q: Describe the structure for the remainder of your testimony.

A. My testimony first provides background sections outlining policies and studies relevant to PSE's decarbonization and DER efforts. I then cover a series of sub-topics covered within PSE's GRC filing, including grid modernization/distributed energy resources, demand response/time-varying rates, and electrification/gas decarbonization. I then wrap up my testimony with a section with conclusions and recommendations.

<u>BACKGROUND AND PORTFOLIO REVIEW</u>

Q: Describe the policy landscape that underlies current PSE grid modernization and decarbonization efforts.

A. Several recent policies have provided discrete requirements guiding PSE investments in grid modernization and decarbonization efforts.

First, Washington's Energy Independence Act (approved in 2006 through the passing of ballot initiative 937) outlines policy goals for energy conservation and renewables targets for state electric utilities. Codified through Chapter 19.285 RCW, PSE is required to set biennial conservation targets to pursue all achievable cost-effective energy efficiency.

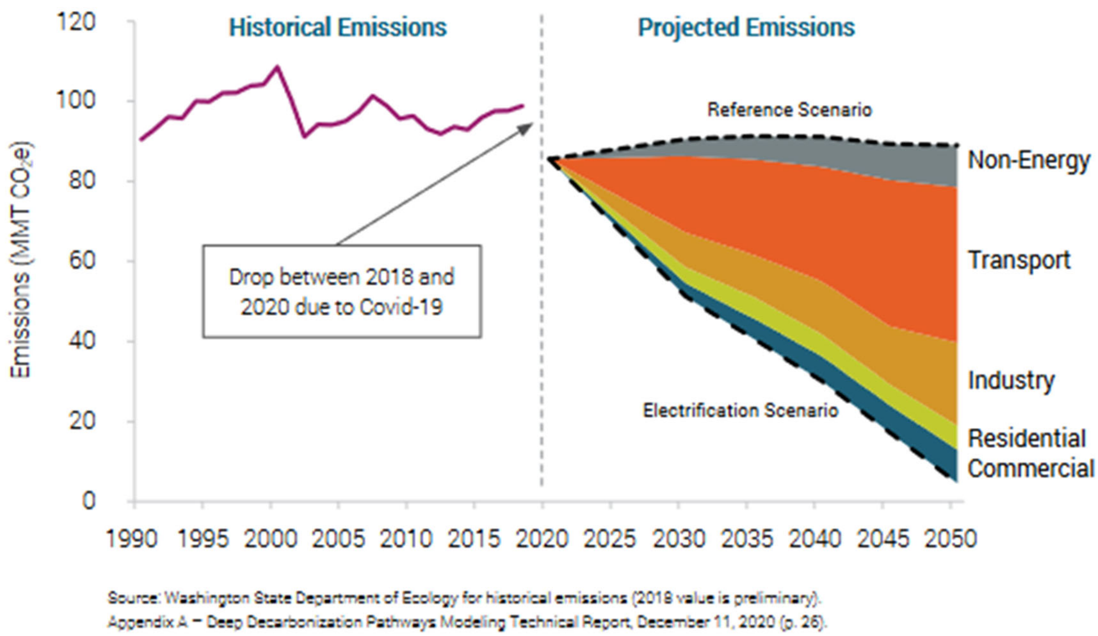
Second, WAC 480-100-5050 (from 2010) provides requirements for utilities to submit periodic reports to the UTC regarding availability and implementation planning of smart grid technologies.

Third, RCW 19.280.100 (enacted as part of CETA in 2019) provides guidance for utility distribution system planning processes, specifically a 10-year plan, with "analysis of nonwires alternatives for major transmission and distribution investments," a process involving stakeholder input and feedback, and to include DERs within the utility IRP.

Fourth, 2019's CETA (19.405 RCW), including the Clean Energy Action Plan ("CEAP") (10-year plan filed within IRP) and Clean Energy Implementation Plan ("CEIP") (4-year roadmap filed in 2021), require utilities to plan for and execute a transition to 100% clean energy. The associated investment in this transition must also achieve an equitable allocation of benefits and reduction of burdens to highly-impacted communities and vulnerable populations (i.e., "named communities").

Fifth, the Washington 2021 State Energy Strategy is a policy roadmap aimed at deep decarbonization of transportation, buildings, and electricity sectors. Figure 1 provides the projected emissions by sector and the proposed electrification scenario. Key sectors contributing to greenhouse gas emissions included transportation (45% of 2018 total), electricity (16%), and buildings and industry (nearly 25%).

Figure 1. Historical and Projected Gross Greenhouse Gas Emissions in Washington State (WA 2021 State Energy Strategy p.16)



The plan includes decarbonization analysis conducted by Evolved Energy Research (EER) which modeled five decarbonization scenarios (using the EnergyPATHWAYS and RIO modeling suite). There are several key implications for driving decarbonization goals through policy, including transportation electrification being the key to cost-effective decarbonization, and electrification in the building sector being less expensive and more energy efficient than an approach focused on creating synthetic pipeline gas (even paired with high-efficiency gas equipment). (p.46)

Finally, the 2021 Climate Commitment Act (CCA) further establishes pathways for achieving state decarbonization goals by putting into place a "cap-and-invest" program that will launch in January 2023. This program will impact a range of industry, including in-state electricity generation and natural gas distribution. The CCA also includes environmental justice and equity provisions that aim to target and prioritize improvements in localized air quality for overburdened communities.

Q. Describe PSE's current DSM/DER portfolio and achievements.

A. Pursuant to Washington State's Energy Independence Act (I-937) (and more recently under the 2019 HB 1257 for gas utilities), PSE has delivered cost-effective conservation through its energy efficiency portfolio. Through an integrated resource planning process, PSE develops a 10-year forecast of conservation potential and sets 2-year targets within its biennial conservation plan; the most recent (2022-2023) includes targets for electric efficiency (536,717 MWh) and natural gas efficiency (9,791,327 therms). Under CETA, PSE has developed a 4-year plan (CEIP, currently 2022-2025) for staging CETA progress towards goals, including an overview of savings targets and a proposed portfolio of efficiency, demand response, and renewable programs (see Figure 2 for proposed targets from the PSE CEIP). Targets for this 4-year period include: energy efficiency (1,073,434 MWh – building off its IRP trajectory), demand response (23.7 MW), and renewables (1,917,068 MWh), the latter of which includes 800 MW of utility-scale renewables, 80 MW of solar, and 25 MW of battery storage.

Figure 2. PSE CEIP – Proposed Savings Targets by Program Area (PSE CEIP, p.4)

Table 1-1: Specific Targets from 2022–2025, Incremental

	2022	2023	2024	2025
Energy Efficiency (MWh)	268,358.5	268,358.5	268,358.5	268,358.5
Demand Response (MW)	-	5	6	12.7
Renewable Energy [Utility-scale] (MWh)	-	-	1,052,863	833,468
Distributed Energy Resources (MW)	7	23	25	25

To date, PSE has focused its conservation efforts on energy efficiency and renewable targets as stipulated through I-937 and has not developed a robust set of program offerings for DR or customer-sited renewables (including solar and storage), with a few exceptions (e.g., non-wires alternative pilots). Under CETA and through its CEIP, PSE has provided savings goals and a list of discrete programmatic strategies for building out these new offerings. PSE prefiled testimony (provided by William Einstein, Joshua Jacobs, and Birud Jhavari) provides further discussions of new program areas for PSE, including its time-varying rate pilot, transportation electrification pilots (i.e., EV charging products and services for residential, non-residential, and low-income customers), demand response pilots (i.e., HVAC and water heating direct load control for residential and medium commercial customers) and distributed energy resource pilots (i.e., solar, batteries).

Q. How does PSE's DER/DSM portfolio compare to those of other regional IOUs?

A. Most notably for DR, PSE's portfolio does not address large commercial or industrial (C&I) demand response applications. While these may come out of the Targeted DER RFP, large C&I DR are common programs for other IOUs, including Tacoma Power, PacifiCorp, and Portland General Electric. For example, in 2021 PacifiCorp issued a solicitation for DR proposals focused on non-residential curtailment, residential/small commercial direct load control (DLC), and irrigation load control, and identified a short list totaling 600 MW. While DR programs are new for PacifiCorp's WA territory, the company anticipates the following programs: C&I curtailment, irrigation load control, thermostat and water heating DLC, batteries, and TOU pilots. Tacoma Power (in its CEIP) proposes 10 MW of demand response through an industrial demand response rate and residential water heating DLC pilot. As another point of comparison, Portland General Electric has been piloting demand response since 2015 and currently has a projected portfolio of residential and commercial/industrial DR achieving l03 MW (summer) and 67 MW (winter) through 2023. Over half of its summer capacity is expected through residential efforts, with its C&I offerings projected to achieve 40 MW (summer) and 34 MW (winter).

CONSISTENCY WITH WASHINGTON CLEAN ENERGY AND CLIMATE POLICY

Q. How would you describe the approach that PSE uses to develop the demand-side portfolio proposed in its CEIP?

A. Consistently within the CEIP and the testimony of Einstein, Jacobs, and C. Koch it appears that PSE is taking a measure-by-measure approach. That is, it appears that PSE analyzed cost-effectiveness, customer benefit indicators, program design, and enabling investment for each technology in isolation.

Q: Is this consistent with the goals of Washington's Clean Energy and Climate Policies?

A: No. While this can be helpful for initially prioritizing measures, it underestimates the value of measures that have synergistic value across the portfolio. For example, weatherization can provide value not only in terms of energy efficiency, but can reduce the peak impact of building electrification, reduce the need for auxiliary heat, increase resilience and safety for vulnerable populations, and increase the per-customer impact and ride-through of smart thermostat demand response programs. Utilities with mature building electrification programs, like Sacramento Municipal Utility District or Green Mountain Power, co-deployed building electrification with DERs, DR, and efficiency to ensure a seamless customer experience, more effective decarbonization, and more cost-effective programs.

I do not see anywhere in PSE's CEIP, IRP, or GRC analysis where PSE analyzed bundling of energy efficiency, DER, DR, and/or electrification measures to achieve its decarbonization targets. This may explain in part why their studies reach very different conclusions about the value of investments in demand response and building electrification compared to the Washington State Energy Strategy, where the full portfolio of investments was analyzed together.

Q. How does PSE value winter and summer capacity? Are temporal and locational values being included?

A. PSE's 2021 IRP[2] overviews several analyses used to assess capacity, including AURORA to develop demand forecast scenarios, GENESYS (developed by NPCC/BPA) to assess regional resources, Resource Adequacy Model (RAM) to estimate peak loads, and a range of metrics, including loss of load probability (LOLP) to assess resource adequacy and effective load carrying capacity (ELCC) to assess peak capacity contributions. Currently, these methods account for seasonality and temperature scenarios, but do not appear to account for temporal or locational value of capacity resources.

Q: How does PSE assess the cost-effectiveness of demand-side resources?

A. To assess cost-effectiveness of demand-side resources, PSE conducts several standard cost tests, with its primary test (per Commission guidance) being a modified total

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[2] https://www.pse.com/-/media/PDFs/IRP/2021/IRP21_Chapter-Book-Compressed_033021.pdf?sc_lang=en&modified=20220307225041&hash=BF3BAD39DDC31F526D46104FC523384E

resource cost (TRC) test. Estimation of the modified TRC follows guidance from the Power Council and includes quantifiable non-energy benefits, a 10% conservation benefit adder, and a risk adder.[3] Additionally, PSE estimates utility cost test, participant cost test, and ratepayer impact measure test. In the BCP cost effectiveness workbooks provided, PSE provides summaries of costs and benefits associated with its program portfolio; however, there is a lack of clarity and detail in some of the underlying assumptions for these inputs, in particular, valuation of energy and non-energy benefits. For example, specific energy efficiency measures like weatherization and smart thermostats interact with demand response by increasing event ride-through potential and per-household capacity savings and by increasing the number of eligible units with enabling devices and associated enrollment probability. Incorporating these assumptions would increase the flexibility benefits associated with the energy efficiency measures, and also would impact the broader potential for demand response resources. Furthermore, assumptions surrounding non-energy benefits appear to be hardcoded in these workbooks which obscures the ability to review per-benefit assumptions both for individual benefits and the range of distinct benefits being included.

The most noteworthy issue in the economic analysis of its demand-side resources is the poor effective load carrying capacity (ELCC) values used. PSE assumes that distributed resources, particularly demand response, contribute very little to its capacity need. The ELCC is used to adjust the avoided cost of capacity benefit from a given resource. Since DR's primary benefit is avoided capacity cost, ELCC is one of the most

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[3] https://www.nwcouncil.org/2021powerplan_cost-effective-methodology/

important assumptions in determining the value of DR. The table below, from Chapter 7 of PSE's 2021 IRP[4], provides their assumed ELCC values for demand response.

Table 1. PSE 2021 IRP ELCC Values for Demand Response

DEMAND RESPONSE	Capacity (MW)	Peak Capacity Credit Year 2027	Peak Capacity Credit Year 2031
Demand Response, 3-hr duration, 6-hr delay, 10 calls per year	100	26.0%	31.6%
Demand Response, 4-hr duration, 6-hr delay, 10 calls per year	100	32.0%	37.4%

This table shows that PSE is giving DR resources between 26% and 37.4% of the capacity value that they would credit to a peaking thermal generator.

By comparison, PGE calculates ELCC for each of its DR resources and for the portfolio overall. The rightmost column in the table below, taken from PGE's 2021 Flexible Load Plan (Exh. JBK-3), shows PGE's modeled ELCC values for each DR resource in its portfolio.

Table 2. PGE 2021 Flexible Load Plan ELCC by Resource Type

Pilot Proposal	2025 MW Target	Pilot ELCC	Modeled ELCC
Time of use	19	100%	90%
Water heaters	22	82%	73%
Electric vehicles	16	100%	79%
Energy Partner	30	44%	63%
Thermostat	74	77%	60%
Peak Time Rebate	26	42%	44%
Portfolio	186	72%	65%

[4] https://www.pse.com/-/media/PDFs/IRP/2021/chapters/07IRP21_Ch7_032921.pdf?modified=20220307201457

This means that PSE is assuming roughly half the ELCC that PGE does on average. At the same time, as outlined in the avoided cost assumptions in its 2022 Targeted DER RFP[5], PSE is using an unadjusted avoided cost of $95 per kw-year. This compares to an avoided cost of $131 per kw-year assumed by PGE.

Q: Why does this matter?

A: The combined effect of these conservative assumptions by PSE is that the utility places an unrealistically high value on central station thermal generators over the demand-side resources. The result is an artificially low target for demand response, which leaves significant system benefits on the table.

Q. Has PSE conducted rate impact analysis or explored any mechanisms to alleviate the energy burden on "named communities" through the proposed rate increase?

A. Yes. Discussed in the Birud Jhaveri testimony, PSE conducted a cost of service study (as required by WAC 480-85), identifying an approximate 10% increase of residential general service. PSE also proposes a bill discount rate (pursuant to RCW 80.28.068) for low-income gas and electric customers – this is a two-tiered rate, providing a 45% discount for customers between 0-30% area median income and 15% discount for customers between 30-50% area median income. PSE has also increased its energy assistance program budget (Schedule 120) by over $10m for the 2023-2025 period.

As described in Jhaveri's testimony, PSE also conducted an Energy Burden Analysis. I commend PSE on undertaking what appears to be a very robust analysis of building

[5] https://www.pse.com/-/media/PDFs/001-Energy-Supply/003-Acquiring-Energy/pdf/ExE_2022-DER-RFP_Avoided-Cost.pdf?sc_lang=en&modified=20220208002001&hash=0CE52410C503394F6C4C304B4E282F03

energy costs. My only area of concern is that it may provide an incomplete view of relevant energy costs given its exclusion of transportation. Under the current methodology, transportation electrification efforts would appear to increase energy burden, when in reality they in almost all cases decrease total energy costs, given the much lower cost of electricity vs petroleum fueling of vehicles. I recommend that going forward energy burden analysis includes these costs, such as the Housing + Transportation Index developed by the Center for Neighborhood Technology[6].

GRID MODERNIZATION AND DISTRIBUTED ENERGY RESOURCES

Q. What role does grid modernization play in the enablement, integration, planning, and operations of DERs and electrification technologies?

A. To some extent, one could argue that DERs and electrification are some of the primary drivers of grid modernization. Greater situational awareness, advanced controls, operational efficiency, and improved forecasting help distribution utilities better optimize the deployment and operation of distributed resources. Whether it be through advanced metering, distribution management systems, hosting capacity tools, or simply improved analytics, utilities with more modern grid technologies should be better equipped to prepare for the energy transition.

That said, this is not meant to imply that grid modernization investments are a prerequisite to DER and electrification nor that grid modernization will lead to improvements in all cases. As an example of the former, utilities in Australia and Hawaii have some of the largest penetrations of rooftop solar in the world and have safely

[6] https://htaindex.cnt.org/about/HTMethods_2016.pdf

interconnected these resources without AMI or DERMS in many cases. Additionally, well-designed rates coupled with advanced autonomous controls, such the latest smart inverter standard (IEEE 1547-2018), can go a long way to managing major issues on the grid.

On the other hand, there are many cases where grid modernization investments have not realized their intended benefits. The most glaring example of this is with early deployments of AMI, where many of the promised high value use cases were never realized. As Dr. Sanem Sergici cites in her testimony (SIS-1T), ACEEE's report on the potential benefits of AMI notes how most utilities have failed to deliver on the full suite of AMI benefits. The conclusions of that report summarize the issue well:

> *We find that many utilities are underexploiting AMI capabilities and attendant benefits, thus missing a key tool to deliver value to their customers and systems. This is due in part to organizational barriers including silos and workforce challenges, data access and sharing issues, and difficulties communicating the benefits and costs of AMI to key stakeholders…* [7]

Q. What are the relevant areas of grid modernization that PSE is investing in related to DERs and electrification?

A. Joshua Jacobs and Catherine Koch identify several key areas of grid modernization in their testimony related to CETA that I'll address in greater detail below. Jacobs notes: "In many cases, these are new investments to implement the CEIP, and in other cases, these are already planned investments that have been accelerated in order to implement the

[7] https://www.aceee.org/sites/default/files/publications/researchreports/u2001.pdf

CEIP." (JJJ-1T, page 26, 4-6). CAK-5 breaks down relevant grid modernization investments into three categories: DER enablers, enablement from grid modernization, and distribution efficiency. These include the following investments: Virtual Power Plants (VPP), Feeder Level Forecasting, Hosting Capacity Analysis, Advanced Distribution Management (ADMS), ADMS Integration, DER Management System (DERMS), Data Lake and Analytics, Substation SCADA, Circuit Enablement-DER and Microgrids, Resilience Enhancement, and Conservation Voltage Reduction.

Q. At a high level, how do these investments differ from the approach taken by peer utilities absent CETA requirements?

A. In many ways, these planned investments look very typical for a modern utility. For example, Portland General Electric (a similarly sized investor-owned utility in the region) is already implementing or in the process of implementing all of the investments described above, and many have been in place for several years. Additionally, while many of these investments benefit clean energy deployment, they also simply provide cost savings and reliability improvements to all ratepayers (as PSE notes throughout its testimony).

Q. What is your impression of how PSE determines if an investment is attributable to CETA?

A. In CAK-1Tr, Koch notes that "CETA expressly directs utilities to consider DERs in their distribution planning. RCW 19.280.100(2)(c) directs utilities to plan distribution investments with the goal of providing the most affordable investments for all customers and to avoid reactive expenditures to accommodate unanticipated growth in DERs" (Page 36-37, line 19-1) as a rationale for how PSE determines CETA influence over capital investment decisions. She further notes that "...CETA, through RCW 19.405.060 (1)(c)(iii), requires that clean energy benefits include energy security and resiliency. Stakeholders value less and shorter outages, which is furthered by grid modernization investments such as targeted circuit reliability programs, addressing aging infrastructure, and adding automation so that when a DER operates on a circuit in a storm, for example, the lights stay on for all customers on the circuit." (page 37, line 6-11).

What's troubling in this explanation is that it seems to imply that investments in modern distribution planning or those that prioritize security and resilience are taking place in response to CETA, and that in the absence of CETA requirements PSE would not see a need to undertake these grid modernization efforts. Drawing the conclusion that any investment that relates to a CEIP requirement is in fact caused by CETA is a troubling precedent, given that CETA covers a broad swath of the utility's business. It would not be surprising to see a utility like PSE undertake many if not all of these investments (in some form or another) over the coming years, absent CETA. For instance, the need to consider security and resilience is simply good planning and it highly unlikely that PSE wouldn't have considered these factors without CETA.

Q. What investments does PSE include in the DER Enablers category and how are their costs allocated?

A. In CAK-5, Koch provides the following breakdown of DER Enabler costs.

Table 3. Summary of DER Enablers Investment Allocation

Capital Plan	% Allocated to the CEIP (%)	Total $ Allocated to the CEIP ($ millions)	Investment covered in Grid Mod - Core 1/1/2019 – 12/31/2025 ($ millions)
VPP	100	9.62	0
Feeder Level Forecasting Tool	0	0	0
Hosting Capacity Analysis	100	6.19	0
ADMS	0	0	7.45
DERMS	100	3.98	0
Data Lake and Analytics	50	3.65	3.65

Q. What are your thoughts on reasonableness of these costs and their allocation to CETA or core grid modernization?

A. In terms of the overall cost level, the requests do not seem plausible for a utility that needs to catch up on grid modernization in light of adoption of DERs and electrification and/or aggressively pursuing programmatic acquisition of distributed resources (as called for in CETA).

The costs for ADMS, VPP, and DERMS investments are within reasonable ranges. The VPP and DERMS costs appear to be priced for enterprise grade solutions (solutions tailored to pilot programs or smaller utilities are often much lower in cost to accommodate smaller scale, with annual costs in the range of hundreds of thousands of dollars). These costs would be more reasonable if PSE had demand response targets in line with peer utilities and its own potential study. However, in the absence of more aggressive targets, one must question whether the level of capital expenditures is reasonable. One could argue that these costs would be incurred at some point by PSE, as they are becoming much more common broadly, though their focus on programmatic DER optimization in the near term appears to be a response to the CEIP DR target. That said, the size of these investments does not seem in line with the relatively paltry proposed acquisition of demand response.

The hosting capacity costs also seem to be within a reasonable range in terms of overall costs. However, nowhere in the discussion of hosting capacity (CAK-5, page 14-15, line 20-10) does Koch note how and why this should be attributed to CETA. The motivations noted are to reduce time and costs and increase transparency. While CAK-5-Appendix B does note that Washington law also motivates these investments, this is secondary to the core business need. If PSE has an investment that makes sense for the business and its customers that also happens to meet a CEIP need, this does not mean that CETA is the driver of that investment. PSE has not sufficiently demonstrated that it would not make this investment in the absence of CETA and therefore these should be general investment priorities, not attributable to CETA.

Assessing the reasonableness of analytics costs can be difficult without detailed knowledge of the scope and scale of the actual work. Nowhere in the discussion of Data Lake and Analytics (CAK-5, page 17-18, line 20-22) does Koch note how and why this should be attributed to CETA. She notes simply that these investments are to improve operational planning and real-time operation. While she notes that this will help maximize DER value, it is not clear that the clean energy investments required by CETA are in any way driving this investment.

Q. What investments does PSE include in the Enablement from Grid Modernization category and how are their costs allocated?

A. In CAK-5, Koch provides the following breakdown of Enablement from Grid Modernization costs.

Table 4. Summary of Enablement from Grid Modernization Investment Allocation

Capital Plan	% Allocated to the CEIP (%)	Total $ Allocated to the CEIP ($ millions)	Investment covered in Grid Mod - Core 1/1/2019 – 12/31/2025 ($ millions)
Substation SCADA - Accelerated	64	41.36	23.27
Circuit Enablement – DER and Microgrids	100	57.5	0
Resilience Enhancement - Expanded	70	18.43	7.9

Q. What are your thoughts on reasonableness of these costs and their allocation to CETA?

A. PSE claims that it originally hadn't planned to update all of its substations to SCADA until 2035 and that CETA is driving this acceleration. This is dramatically out of sync with best practices for a utility of PSE's size. While not all of PSE's peer utilities have full substation coverage, they are almost universally planning to get there within a reasonable period of time. Substation SCADA is a basic and fundamental requirement for nearly all other grid modernization initiatives, really representing a prerequisite investment for nearly all the advanced applications the utility proposes here. I agree that PSE should update its substations on a more accelerated timeline (since SCADA is such a foundational investment for distribution planning and operations) but it is unreasonable to attribute any of this acceleration to CETA.

It is not clear from the DER and Microgrid and Circuit Enablement description within CAK-5-Appendix B how this would materially differ from costs that would be incurred as a part of interconnection. In the business case within Appendix B, PSE outlines the following tasks associated with this investment:

- *Upsizing of assets such as conductors and service transformers to accommodate additional renewable energy capacity*
- *Additional line capacitors/regulators and/or substation transformer upgrades for*

voltage regulation

- *Additional reclosers and protective relays to form microgrids*
- *Substation upgrades such as smart circuit breakers, 115 kV circuit switchers, or communications to protect system from higher fault currents*
- *Improving communication networks for granular loading data*

The above list is simply a set of common upgrades incurred to interconnect DERs generally. More information—such as a programmatic proposal, cost-effectiveness analysis, and oversight process for determining where and why microgrid interconnections should be included within rate base—is necessary in order to make a prudency determination regarding this investment. This is an advanced use case for a utility that claims, pre-CETA, that it was not planning to fully cover its substations with SCADA until 2035. If an investment like this were to proceed, it would require systematic and transparent distribution system planning, since it's not clear how the prudence of these investments would be assessed. I would therefore argue that these costs (Circuit Enablement – DER and Microgrids) should not be approved at this time and that they should be subsequently considered within a comprehensive distribution system planning process.

Q. Do you have any concerns related to PSE's Distribution Efficiency investments?

A. I do not; they seem reasonable and in line with best practice. CVR is an important and highly cost-effective tool for managing voltage and reducing losses on the distribution grid.

Q. What are the DER measures proposed by PSE?

A. The DER targets proposed in the CEIP are the same as in the 2021 IRP preferred portfolio. Under the Renewable Energy Target, PSE is proposing a DER sub target total of 80 MW of distributed solar PV and 25 MW of battery energy storage system (BESS).

Q. What is the potential for solar and storage deployment in PSE service territory? How does this relate to PSE proposed measures?

A. The CPA conducted by Cadmus for the 2021 IRP indicates a solar achievable potential of 87 MW for the residential sector and 249 MW for the commercial sector, for a total of 336 MW in a business-as-usual scenario.[8] Under the advance cost decline scenario, the residential sector increases to 165 MW and the commercial sector to 457 MW, for a total of 622 MW. The latter scenario becomes more viable with the recent 24-month tariff exemption on solar panel imports from four Southeast Asian countries set by President Biden in June 2022.[9]

SEIA reports that Washington residential and commercial solar installations increased by 170 MW in the last 5 years (2017 -2021), and it forecasts a growth of 622 MW for the next five years. However, this projected growth includes utility installations. Therefore, taking a conservative approach and considering the potential of the business-as-usual scenario, as well as the fact that PSE has largest retail sales by one order of magnitude accounting for 25% of the total in Washington state, I believe the 80 MW target for DER solar is reasonable for the first CEIP and an achievable goal by 2025.

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[8] https://www.pse.com/-/media/PDFs/IRP/2021/appendix/16-IRP21_AppE_033021_FileUpdate-with-report.pdf?modified=20220307202829

[9] https://www.reuters.com/world/us/biden-waives-solar-panel-tariffs-invokes-defense-law-white-house-confirms-2022-06-06/

Q. What kind of response has PSE received in its RFPs in terms of distributed solar and storage?

A. Unlike demand response, where there was a wide range of responses, there has been a relatively muted response from vendors on distributed solar and storage. PSE received no offers within its all-source RFP. For its targeted DER RFP, PSE received one offer for solar equipment installation services and 3 MW of battery energy storage.

The stark mismatch between PSE's targets within the CEIP and the market response in its RFPs so far is notable. This is likely due in part to the conservative valuation approach I discuss in the background section above. PSE seems intent on procuring capital-intensive resources such as solar and storage, despite tepid response from vendors. Its DER targets are not unreasonable and are in line with market potential, but would be relatively aggressive programmatic targets when compared to its peer utilities. Meanwhile, the company has fairly weak demand response targets, out of sync with what would be expected of a utility its size and despite a robust market response from its targeted DER RFP.

DEMAND RESPONSE AND TIME-VARYING RATES

Q. What type of demand response programs are in the market today?

A. As defined by the Federal Energy Regulatory Commission ("FERC"), demand response refers to "Changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized."[10]

In regions where there is lack of an organized wholesale market, such as the Pacific Northwest ("PNW"), the predominant form of demand response is retail programs. In this case, utilities use demand response to meet their own system requirements (typically resource adequacy) and allow the resource to have an impact on the wholesale market only in that it shows up as a change in net load requirements. The other form of demand response is wholesale offerings, where aggregators and/or utilities bid demand response assets into wholesale markets directly using the relevant participation mechanism.

Demand response can be achieved through different types of programs such as interruptible tariffs, price-based options, residential and commercial direct load control ("DLC") programs, thermal and energy storage, and automated demand response ("ADR"). Residential direct load controls programs include smart thermostats, smart water heater controls, HVAC and water heater switches, pool pump controls, and smart EV charging. Price-based options include time-of-use, peak time rebates, critical peak pricing, real time pricing, and demand charges.

Q. What type of demand response programs is PSE currently offering?

A. PSE offers a Voluntary Load Curtailment Tariff under Schedule 93, for commercial and industrial customers capable of reducing their demand by 500 kW, and a High Voltage Interruptible Service under Schedule 46, appliable to customers with three phase and

[10] https://www.ferc.gov/electric/industry-activity/demand-response/national-assessment-and-action-plan-demand-response

delivery voltage of 50,000 or higher.[11] Nevertheless, based on Form EIA-816,[12] as of 2020, PSE did not report any data for demand response activities. Previously, PSE has piloted a demand response program for commercial customers to reduce system peak during cold winter mornings and afternoons and has tested demand response with Nest thermostats but currently,[13] the utility is not offering any of these demand response programs to its customers.

Q. What is the DR potential in PSE territory and the region broadly?

A. The Conservation Potential Assessment and the Demand Response Assessment (CPA) conducted for the 2021 IRP calculates a DR potential for winter peak of 226.4 MW by 2045, which represents 4.5% of the peak based on a winter peak demand of 5,029 MW.[14] Therefore, the current CEIP DR target of 23.7 MW by 2025 is a low bar given the potential for DR in PSE service territory. While there were no bidders for DR on the All Resource RFP of 2021, in 2018, the All Resource and DR RFP received 6 proposals for a total of 154 MW.[15] Furthermore, the DER RFP of 2022 received a total of 161.1 MW.[16] The results of these RFPs indicate that PSE is missing a significant opportunity to reduce winter peak demand. In order to deliver more clean capacity, PSE should be targeting

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[11] https://www.pse.com/en/pages/rates/electric-tariffs-and-rules#sort=%40documentdate%20descending

[12] https://www.eia.gov/electricity/data/eia861/

[13] https://www.pse.com/en/pages/grid-modernization/demand-response

[14] https://www.pse.com/-/media/PDFs/IRP/2021/appendix/16-IRP21_AppE_033021_FileUpdate-with-report.pdf?modified=20220307202829

[15] https://www.pse.com/-/media/PDFs/001-Energy-Supply/003-Acquiring-Energy/PUBLIC_RFP_Proposal_Summary_Report_with_Attach_A.pdf?sc_lang=en&modified=20211115231311&hash=40A7756F3A7320AACB5A7D390DB5A275

[16] https://www.pse.com/-/media/PDFs/001-Energy-Supply/003-Acquiring-Energy/pdf/DER-RFP-Proposal-Summary-Report.pdf?modified=20220418202909

higher levels of DR to achieve its goals, reduce overall system costs for customers, and comply with state regulations on greenhouse gas emission reduction and decarbonization of the energy sector.

Regional studies also indicate that the demand response potential is much larger than what PSE is aiming for in their CEIP. A study from Cadmus and Lighthouse estimates the demand response 20-year achievable potential for BPA west territory area as approximately 9.5% of summer peak demand and 6.3% of winter peak demand, with the residential sector accounting for more than half of the MW (Exh. JBK-4). It is worth noting that the 5-year cumulative achievable potential is almost the same as that of the 20-year cumulative achievable potential, with each around 1,000 MW in both seasons. These results assume adoption of energy efficiency measures, which will reduce the amount of DR potential in the residential sector over time. Similarly, Navigant assessed the DR potential for the Seventh Power Plan and found that the cumulative load impact as a percentage of peak demand for the Northwest was 8.8% for the winter peak and 8.2% for the summer peak, with around 3,000 MW potential in both seasons.[17] According to ACEEE, in general, demand response programs can reach peak demand reduction of 10% or more.[18]

The 2021 Northwest Power Plan identifies 3,721 MW (summer) and 2,761 MW (winter) of DR potential for the region, which reflects a range of 23 products (including price-based and controllable resources) across different sectors. In particular, the plan

[17] https://www.nwcouncil.org/sites/default/files/npcc_assessing-dr-potential-for-seventh-power-plan_updated-report_1-19-15.pdf

[18] https://www.aceee.org/blog/2017/02/demand-response-programs-can-reduce

recommends that utilities consider several specific low-cost, frequently deployable DR strategies: residential time-of-use rates and demand voltage regulation, which assumes 200 MW and 520 MW of available capacity by 2027, respectively (Northwest Power Plan, 6-41).[19] The plan also highlights that DR resources provide benefits beyond the power system, including providing relief for transmission constraints and deferred infrastructure investment. It also recommends utilities leverage energy efficiency infrastructure to co-deploy DR offerings as part of an integrated DSM approach. Considering the 2020 winter peak demand of 4,245 MW[20] and based on benchmarking studies of DR impact as percentage of winter peak demand, PSE demand response capacity could be in the range of 267 MW to 424 MW by 2025, signaling just how alarmingly low the current target in the CEIP (23.7 MW) is. This is supported by the response to PSE's own DR potential study and responses to its DER RFP, where it had 160 MW of bids in Tier 1.

Q. What are PSE's goals for its DR resource and growth strategy? How does PSE's DR target compare to other utilities in the State?

A. In contrast to other parts of the country, historically the PNW has been characterized by a lack of DR programs due to cheap and reliable hydropower generation. However, with increased frequency and intensity of extreme weather events, especially heat waves and wildfires, as well as the development of legislation requiring decarbonization of energy generation, DR interest has recently surged among utilities in the region.

[19] https://www.nwcouncil.org/sites/default/files/2021powerplan_2021-5.pdf

[20] https://www.eia.gov/electricity/data/eia861/

Outside PSE stating in their CEIP that they must aggressively pursue demand response programs, the company has put forward no long-term targets or a strategy or plan for developing and growing this resource. The 2021 IRP and the DR RFP are the only documents referencing the incremental resource additions of DR through 2026 to 2031 (167 MW) and 2032 to 2045 (21 MW). Furthermore, the proposed mix of DR products and reluctance to scale programs with proven effectiveness does not reflect the level of commitment I would hope and expect to see.

The CEIP sets a DR target of 23.7 MW for the period 2022-2025, which, as stated previously, is a low bar given the potential in PSE service territory, especially for a company claiming that they need to aggressively pursue DR programs. As a comparison, Avista has set a target of 30 MW of DR in their CEIP [21] while Tacoma Power is aiming for 10 MW by 2025,[22] with both utilities being significantly smaller than PSE. According to Form EIA-861, in 2020, PSE accounted for 25% of total retail sales of electricity in Washington,[23] being the utility with most sales by an order of magnitude over other utilities in the state. Given the larger customer base and having a leading position in the state, PSE should increase their DR target to *at least* 160 MW.

Table 5 shows CEIP program breakdown of the demand response target. All proposed programs are DLC-type programs focused on the residential sector, accounting for 93% of the total MW target. While residential customers accounted for 54.6% of PSE

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[21] https://www.myavista.com/-/media/myavista/content-documents/about-us/ceip/clean-energy-implementation-plan.pdf

[22] https://www.mytpu.org/wp-content/uploads/CEIP-Draft-Report.pdf

[23] https://www.eia.gov/electricity/data/eia861/

total retail sales in 2020 (20,088,222 MWh), the company is missing the opportunity to tap into their commercial and industrial customers, which account for more than 40% of total retail sales.[24] This group of customers can subscribe to a DLC program or can also be better served with an interruptible tariff providing significant peak load reduction. For instance, Avista's 30 MW will be mainly provided by one industrial customer.

Table 5. PSE CEIP DR 2022-2025 Programs

	Projected MW in 2025
Residential Direct Load Control (DLC) Heat — Switch	16.41
Residential DLC Heat — Bring your own thermostat (BYOT)	0.36
Residential DLC Electric Resistance Water Heater — Grid Enabled	5.10
Residential DLC Heat Pump Water Heater — Grid Enabled	0.08
Medium Commercial DLC Heat — Switch	1.71
TOTAL PROGRAMS	23.66

Based on Tables 1 and 2 of the DER RFP Exhibit J, Demand Response Addendum,[25] which lists customers by count and rate class, several types of industries listed are good candidates for interruptible tariffs, including manufacturing loads, utilities working in waste management and remediation services, and some agricultural activities such as irrigation. This and all previous stated evidence shows that PSE targets for DR can be improved not only in MW targeted but also in the type of DR programs proposed.

Q. What are the costs associated with DR programs as described in the CEIP? How do these compare to other studies in the region?

[24] https://www.eia.gov/electricity/data/eia861/

[25] https://www.pse.com/-/media/PDFs/001-Energy-Supply/003-Acquiring-Energy/pdf/ExJ_2022-DER-RFP_DR-Addendum.pdf?sc_lang=en&modified=20220208001642&hash=FC22EEF5844ED7D3DA64134ABAF1591B

A. The CEIP indicates an incremental cost of $4m over the planning period, though these costs will be updated following selections from the targeted DER RFP.

While it is difficult to disentangle all the drivers of these costs, one red flag is PSE's assumptions around the levelized cost of capacity from DR products. As a benchmark, here is BPA's expected levelized cost for winter demand response from its most recent potential study.

Table 6. BPA Levelized Cost of Winter Demand Response[26]

Product Option	Levelized Cost ($/kW-year)	5-Year Achievable Potential (MW)	10-Year Achievable Potential (MW)	20-Year Achievable Potential (MW)
Residential DLC - ERWH Switch	$76	145	55	9
Residential DLC - ERWH Grid-Enabled	$25	72	232	165
Residential HPWH DLC Switch	$232	7	9	6
Residential HPWH DLC Grid-Enabled	$98	3	39	111
Commercial DLC - Medium HVAC Switch	$12	5	5	6
Commercial DLC - Small HVAC Switch	$33	6	6	7
Residential DLC – BYOT	$4	89	149	182
Residential DLC - EVSE Switch	$113	4	8	26
Residential DLC - HVAC Switch	$31	73	94	109
Commercial Demand Curtailment	$21	60	62	67
Industrial Demand Curtailment	$17	100	103	109
Residential Rate-Driven DR - TOU	$26	33	34	37
Residential Rate-Driven DR - CPP	$3	53	55	59
Commercial Rate-Driven DR - CPP	-$6	58	61	66
Industrial Rate-Driven DR - CPP	-$7	27	28	29
Utility DVR	$0	193	124	19
Total	**N/A**	**929**	**1,066**	**1,005**

The table below then shows the comparable levelized costs from PSE's latest RFP. In nearly every case, PSE shows substantially higher costs of capacity. This results in higher program cost for DR programs and therefore higher recovery from rates, resulting in

[26] https://www.bpa.gov/-/media/Aep/energy-efficiency/demand-response/bpa-demand-response-potential-assessment-2022-2043.pdf

increased bills for customers. Additionally, the higher levelized costs of energy of certain programs render them as not cost effective or not worth pursuing. An example of this is the levelized cost for PSE commercial and industrial demand curtailment that is 4.5 times higher than that of BPA's potential study.

Table 7. PSE Levelized Cost of Winter Demand Response

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

Q. What is the interaction between DR and PSE's existing EE portfolio?

A. As part of their energy efficiency program, PSE offers customers a $500 rebate for high efficiency heat pump water heaters.[27] Additionally, through the midstream rebate program,[28] PSE partnered with distributors to offer contractors incentives at the point of sale for heat pump technology, including heat pump water heaters. By Washington state law (HB 1444 passed in 2019),[29] all electric storage water heaters manufactured on or after January 1, 2021 must have a modular demand response communications port

[27] https://www.pse.com/en/rebates/water-heating/heat-pump-water-heater-rebate

[28] https://www.pse.com/en/rebates/midstream

[29] https://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bill%20Reports/House/1444-S2%20HBR%20FBR%2019.pdf?q=20220701084619

compliant with certain standards in order to be sold, installed or offered for lease, sale or rent in the state.[30] This requirement creates an opportunity for PSE to tap into a grid enabled resource and develop a DR program with customers that take advantage of these rebates.

Within their EE portfolio, PSE has been offering home energy report (HER) programs since 2008 but they do not include a behavioral DR (BDR) component. Oracle has proved that combining HER and BDR creates additional savings.[31] This finding is further backed by Brandon et al research showing how these social nudges reduce peak load electricity consumption by 2% to 4% when applied in isolation and up to 7% when implemented simultaneously.[32] I suggest PSE take advantage of a well-established efficiency resource to obtain additional cost-effective peak load reduction.

A similar opportunity can be capitalized in the manufactured home segment. Given that manufactured homes are already participating in HER programs, they make ideal candidates for BDR programs. Additionally, PSE offers heat pump and heat pump water heater rebates as well as smart thermostats rebates for upgrades to manufactured homes,[33] making them excellent candidates to participate in DLC DR programs as well. Furthermore, in their 2022-2023 Biennial Conservation Plan (BCP),[34] the company states

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[30] The CTA-2045 standard for water heaters was scheduled to go into effect in January 2021, but supply chain issues prompted the Washington Department of Commerce to suspend the rule. Currently, the Department has proposed to establish a permanent effective date of January 1, 2023 for this standard. https://content.govdelivery.com/accounts/WADOC/bulletins/31d526f

[31] https://blogs.oracle.com/utilities/post/behavioral-demand-response-and-hers-are-better-together

[32] https://www.pnas.org/doi/10.1073/pnas.1802874115

[33] https://www.pse.com/en/rebates/manufactured-homes

[34] https://www.utc.wa.gov/casedocket/2021/210822/docsets

that they will be offering increased equipment incentives as well as customized HERs for manufactured homes customers, making DR a no regret option in this segment.

Q. What role do rates play in managing peaks?

A. PSE rightly points out the importance of rate design in managing costs and carbon moving forward: "...[T]he Company strongly supports exploring time-varying and other outcome-based pricing mechanisms as tools to help manage system and local peaks, reduce customer costs, and help integrate variable renewable generation." (WTE-1CT Page 13, line 11-14). In Sergici's testimony, she notes that TVR benefits are the largest Tier 1 benefit in her analysis (SIS-1T, Figure 3). She further cites the commission order WUTC v. Puget Sound Energy, Dockets UE-190529/UG-190530, et al., Final Order 08/05/03 ¶157 (July 8, 2020), which notes time of use as one of the critical priorities for the UTC.

Q. What is PSE experience with TVR program/pilots and what is PSE proposing within the GRC?

A. The time varying rate (TVR) pilot program proposed in this proceeding will be the first of its kind for PSE. The company is proposing TVR through two different rate designs: time-of-use (TOU) and peak time rebate (PTR). Due to the lack of TVR data for winter peaking utilities as explained by the company, the pilot program will run for two years to collect information and then set the calibrated rates as opt-in tariffs. The table below (Table 4-2 in CEIP) shows the proposed TVR programs and their potential for peak reduction.

Table 8. Proposed TVR Program Parameters

Rate	Season	Ratio (P:OP)[55]	Estimated Peak Demand Reduction	50% Derate for Winter Peaking System[56]
Residential TOU	Winter	5.2:1	10.9%	5.5%
	Non-winter	2.8:1	6.8%	3.4%
Residential TOU+PTR	Winter	2.3:1	5.5%	2.8%
	Non-winter	2.2:1	5.2%	2.6%
	Event day	8.4:1	11.0%	5.5%
Residential Three-period TOU Electric Vehicle (EV)	Winter	7.5:1	12.6%	N/A
	Non-winter	3.6:1	11.9%	N/A
Small C&I TOU+PTR	Winter	2.4:1	5.8%	2.9%
	Non-winter	2.3:1	5.5%	2.8*
	Event day	8.9:1	11.3%	5.7%

The estimated peak demand reductions are consistent with an assessment from Brattle Group on TOU pilots implemented by Maryland utilities, which show 5.1% to 6.1% peak reduction outside summer months.[35] Additionally, another Brattle study of aggregated results of TOU rates indicates that the greatest impact on peak demand occur at a peak to off-peak ratio of 5:1.[36] Similar results were found when assessing/designing different TOU rates during my time at PGE. While PSE is a winter peaking utility and the focus is on reducing the demand load during peak times, I would suggest PSE maintain the same TOU rate throughout the year. This would make it easier for customers to get habituated with this type of differential pricing, and most importantly, it would help optimize the

[35] https://www.brattle.com/wp-content/uploads/2021/05/19973_pc44_time_of_use_pilots_-_year_one_evaluation.pdf

[36] https://www.brattle.com/wp-content/uploads/2021/05/17904_a_survey_of_residential_time-of-use_tou_rates.pdf

system outside winter months. Moreover, summer peak has already increased in the PNW due to a significant increase in cooling deployment in the last years, and summer temperatures will keep rising in the region with heat waves becoming more frequent due to climate change.[37] Thus, maintaining the same TOU pricing across seasons will enable system optimization and new opportunities for load management.

Q. How does this compare to what other utilities in the region are doing?

A. In the PNW, TOU rates are becoming widespread with several utilities offering them in some form. Seattle City Light, Snohomish PUD, and Orcas Power and Light offer TOU rates currently. PacifiCorp offers TOU rate for some parts of their service territory and has a recently established a residential TOU rate in Washington.

In Oregon, Portland General Electric (PGE) has tested different pricing and behavioral demand response program designs for Flex, its Residential Pricing Pilot. Overall findings from the Cadmus evaluation shows that Flex can achieve customer demand savings while managing system peak demand, with a positive customer experience as a result.[38] PGE tested three types of TVRs: PTR, TOU+PTR, and TOU. Demand savings were higher for PTR participants, followed by TOU+PTR and TOU respectively. Higher savings for PTR are explained by the higher consumption baseline used to calculate the rebates. Additionally, customer satisfaction was higher for PTR participants, since they are getting a monetary rebate for shifting load, which ultimately increases the cost of the program. It is worth noting that the maximum TOU peak to off-peak ratio was 2.6:1, which is way below the ratio to achieve the greatest impact on load

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[37] https://cig.uw.edu/learn/climate-change/

[38] https://edocs.puc.state.or.us/efdocs/HAH/um1708hah91734.pdf

demand (5:1 as referenced above). While a PTR has a greater load impact on an event basis, a TOU rate provides all year load reduction that can help optimize the system as a whole and increase available capacity for new incoming load. Based on the results of this pilot, PGE now offers TOU and PTR rate options to all of its customers.

Q. Will the TVR rollout strategy effectively achieve the potential benefits?

A. The design of the TVR offerings, as outlined in Faruqui and Einstein's testimonies, appears robust from an analytical and stakeholder engagement perspective and I commend the utility on its work to develop these options. They have demonstrated that TVR can provide benefits to all ratepayers in a comprehensive and cost-effective manner while protecting vulnerable populations from potential volatility. Considering the focus on named communities in the state, TVRs offer all customers, even those without enabling technologies, the possibility to save on their energy bills. Several utilities in the nation are beginning to roll out default TVRs in their service territory as a cost-effective and equitable solutions to support their increasing capacity needs. A study from Brattle Group shows how low- and moderate-income (LMI) customers respond to TOU prices in a similar manner to non-LMI.[39] If concerns to vulnerable populations remain, bill protections could be included in these rate programs to protect named communities from unexpected rate shocks where applicable. Furthermore, PTR is a no risk option for vulnerable populations.

My only concern about PSE's TVR proposal is with respect to its rollout strategy, where there appears to be a prioritization of demand impact estimation at the expense of

[39] https://www.brattle.com/wp-content/uploads/2021/05/19973_pc44_time_of_use_pilots_-_year_one_evaluation.pdf

broader realization of benefits. The initial pilot would cost $7.5 million and only covers 7,500 customers, and would not be available to all customers for several years. Given that there is already ample evidence of the effectiveness of these rates as demonstrated through the dozens of pilots outlined in SIS-1T and AF-1T, including several here in the Northwest, I am puzzled by PSE's delay in implementation of TVR.

This is particularly true given that PSE is testing rates structures (TOU, PTR) broadly offered in the West (including on an opt-out basis in CA and in PGE's Smart Grid Testbeds). If PSE wanted to test more innovative designs, such as real-time prices or demand charges, it would be understandable. However, for basic TOU, it's not clear what is gained by having such a limited rollout for such a long period of time before offering the program more broadly. A compromise may be to offer an opt-in program to its entire customer base, while piloting more innovative designs on a subset of customers. This should allow for important learning while creating the greatest benefit for customers.

Q. Are cost estimates reasonable for the proposed TVR pilot? How would one expect pilot costs to relate to the cost of a full scale deployment?

A. PSE proposes $7.5 million in costs to deploy the pilot over 3 years (see table below taken from WTE-1T). Most noteworthy is that $6 million of that is for capital expenditures on software upgrades, a very large sum for a pilot only covering 7,500 customers. PSE notes that this is for new digital engagement features and billing enhancements that will benefit all customers during a full-scale rollout. However, it is not clear from PSE's filing how much larger this capital cost might be for a full-scale program or if it would remain the same.

Table 9. Proposed TVR Pilot Budget

Category	2023	2024	2025	Total
Capital	$6M	-	-	$6M
O&M	$655K	$295K	$599K	$1.5M
Total	$6.7M	$295K	$599K	$7.5M

For comparison, PGE launched its Flex Pricing Pilot in 2015, which tested 12 experimental designs including three TOUs, opt-in PTR, opt-out PTR, and opt-out Behavioral Demand Response (BDR). That pilot lasted through 2018 and had a total requested budget of $2.5 million[40] despite including more complex offerings and including nearly 14,000 customers (versus the 7,500 targeted by PSE).

If PSE is going to incur such a large capital expense, it should be creating value for all its customers. I would recommend, given the robust design and ample evidence of the effectiveness of TVR, that PSE offer these opt-in rates to all customers and adjust as necessary based on learnings from the evaluation.

ELECTRIFICATION AND GAS DECARBONIZATION

Q. What tools do gas utilities have available to decarbonize their systems?

A. Gas utilities have a daunting task ahead of them as they seek to decarbonize their systems. Unlike electric utilities, they do not have a suite of cost-effective renewable replacements for their product that can be scaled quickly. Gas decarbonization plans typically include four pillars, ordered by their relative cost/difficulty: methane leakage reduction, energy efficiency, electrification, and decarbonized fuels.

[40] https://edocs.puc.state.or.us/efdocs/HAU/um1708hau132951.pdf

Energy efficiency remains a key pillar in decarbonization. While thermal efficiency of gas end uses is beginning to plateau, there remains a tremendous opportunity to improve the envelope of buildings, particularly in existing homes and multifamily. Weatherization helps to reduce overall space conditioning needs (and thus cost/complexity of electrification) while also improving health and comfort and helps to mitigate increasing electric peak load during summer.

Q. What role does building electrification play in gas decarbonization?

A. In Washington and across the country, there is growing consensus that electrification, particularly in the residential and commercial segments, is the most cost-effective and realistic means to reduce the carbon impact of buildings at the scale required to address policy/climate goals. The Washington State Energy Strategy makes this point clearly and this is further buttressed by efforts in states like California, Massachusetts, and others, where statewide energy efficiency targets are being replaced with carbon-based program targets that place an emphasis on building electrification measures.

Washington utilities are particularly well suited for this transition given the region's high level of maturity in deploying efficient electric space and water heating technologies in their DSM portfolios. This is doubly true for utilities on the western side of the state, where relatively milder weather means that the need for auxiliary resistance heat can be reduced or avoided altogether when electrification is coupled with energy efficiency.

Building electrification is particularly cost-effective where it reduces the need for gas infrastructure in the near or long term. When applied in new construction, electrification can avoid the need for gas infrastructure, providing substantial cost savings. This is why many states and jurisdictions, such as Washington, are beginning to pursue building codes that severely restrict and/or eliminate altogether the use of natural gas in new buildings.

Q. What analysis has PSE done of building electrification?

A. Jacobs's testimony included exhibits that outline the analysis PSE had conducted by E3 to examine options for decarbonizing PSE's gas system. The E3 analysis focuses on two scenarios to achieve net zero carbon by 2045, one with full electrification and one that uses hybrid electrification, where heat pumps are combined with electric furnaces. The E3 analysis notes that both scenarios can meet PSE's goals with similar impacts on electric and gas rates, but the full electrification scenario that E3's report and PSE's testimony focus on would result in substantially larger peak electric demand due to heat pumps switching to auxiliary resistance heat during peak days.

Q. What limitations do you see in this analysis?

A. There are several issues with the analysis conducted by E3. This analysis is discussed in depth by Mr. Burgess, as it relates to PSE's decarbonization strategy. My testimony focuses on the technologies considered in the analysis and how they are assumed to be delivered. These fall into three high-level categories: cost assumptions, baseline definition, and technologies considered. I consider each category in greater detail below.

In its assessment of renewable fuel technologies, such as renewable natural gas, synthetic methane, hydrogen, and direct air capture, E3 rightly applied learning curves to the technologies, as is best practice for emerging technologies where there are economies of scale in the manufacturing process. This phenomenon has been well established for clean technologies like wind and solar and there's no reason to expect this would be different for electrolyzers or biodigesters. However, E3 does not appear to apply this same technique to cold climate heat pumps or heat pumps broadly. Given that E3 excluded efficient cold climate heat pumps from its analysis on the basis of first cost and then argues that peak impacts are caused by a lack of cold climate heat pumps, this appears to be an important omission. From an outsider perspective, it gives the impression that the utility selectively developed their analysis in order to favor preservation of the gas system, in defiance of the growing consensus around building electrification.

Another issue related to cost is a lack of nuance with respect to gas (fossil and RNG) supply costs, both in terms of fuel and delivery. The E3 analysis uses natural gas fuel costs that don't account for the dramatic rise in average cost and volatility we are now seeing in the market across the country. Additionally, they do not highlight any reduction in delivery costs from deferred or avoided distribution infrastructure. This can be a substantial benefit, particularly in new construction (Mr. Burgess's testimony estimates this value at approximately $6,545 per customer).

The baseline assumed in the E3 analysis also appears to be lacking, ignoring two important trends in Washington: increased cooling penetration and increasingly stringent building codes. The E3 analysis appears to assume that air conditioning penetration does not increase over time, and therefore compares the incremental cost of heat pumps against a heating only solution in many cases. However, particularly given the 2021 heat dome event, there is a well-established growth in air conditioning penetration, in many cases as a matter of public health (in a telling indication of this trend, LIHEAP in WA now provides incentives for cooling). This is problematic, as the incremental cost of a heat pump over a unitary air conditioner at scale is expected to be quite low. As noted in a technical report by CLASP[41], at scale the incremental could be as low as $60-$75 per unit.

Additionally, the analysis appears to keep building codes static, without acknowledging improved efficiency requirements. This is an important assumption given that heat pump performance is dramatically affected by the effectiveness of the building envelope, which we should expect to improve substantially in the coming years. Additionally, many building codes at the state and local levels are looking to move toward full or partial bans on natural gas use in specific applications.

My third category of concern is around the technologies considered in the analysis and how they are assumed to be delivered. As discussed above in my testimony, PSE does not appear to be taking a holistic approach to the analysis of its program measures. The impact of this siloed approach is readily apparent in the E3 analysis. The analysis does not consider bundled delivery of energy efficiency, solar, storage, or (most critically) demand flexibility. As noted in RMI's paper, The Economics of Electrifying Buildings:

> *Widespread electrification will add substantial new load to the electricity system, and if not well managed could eventually impose large costs on the electricity system at both the bulk and local levels. Demand flexibility can shift load from high-cost to low-cost times, minimize contribution to system peak (especially in winter), and help cost-effectively integrate high penetrations of variable renewable energy. The value of this demand flexibility to the system will increase in the future, as growing*

[41] https://www.clasp.ngo/research/all/3h-hybrid-heat-homes-an-incentive-program-to-electrify-space-heating-and-reduce-energy-bills-in-american-homes/#

renewable generation introduces more extended periods of zero or negative marginal pricing in electricity markets, while increasing the need for fast-ramping resources to balance the system. Energy efficiency can substantially reduce the total energy use and peak demand, especially for space heating. The efficient new construction buildings modeled in our analysis consume roughly half the energy for space heating as the existing buildings in the same cities.

It is disingenuous to cite potentially 17 GW of peak impacts, as E3 does in its full electrification scenario, without considering how a more effective design might avoid these peaks. Installing cold climate heat pumps in homes with efficient building shells and equipped with grid interactive controls should result in dramatically lower peak impacts. Further, potentially including technologies like battery or thermal storage could eliminate those peaks entirely.

Q. How has PSE integrated the results of its gas decarbonization study into its plans?

A. It's not clear from the testimony provided. The load forecast and revenue requirements analysis provided do not appear to include assumptions around electric growth/gas decline even using the hybrid approach favored by the E3 analysis. These assumptions impact the load forecasts for both electricity and gas, creating pervasive impacts on the revenue requirements for both sides of the business. This means an underestimation of the potential pressure downward on electric and upward on gas rates one would expect from electrification measures.

Jacobs's testimony identifies four pathways for decarbonization to comply with the CCA: (1) methane emissions reduction, (2) conservation and demand side resources, (3) targeted electrification, and (4) alternative fuels (e.g., RNG). The third pathway refers to a Hybrid Heat Pump Pilot included in the 2022/2023 Biennial Conservation Plan (which effectively reflects the second pathway, as this is the only electrification offering presented in the plan), which appears to be aimed at installing heat pumps in households with gas furnace backup, rather than replacing gas heat entirely. PSE rationale for this pilot referenced the E3 study and two issues regarding a more widespread strategy for building electrification using heat pumps: (1) effectiveness under WA climate conditions, and (2) impact on exacerbating winter peak loads. Regarding the first issue, PSE's focus on spikes in peak electric loads in colder temperatures due to electric resistance does not appear to acknowledge the effectiveness of cold climate heat pumps. A 2017 Cadmus evaluation of cold climate heat pumps in Vermont conducted a metering study of 77 units over two heating seasons and found equipment operating below 30 degrees did not exceed an average demand of approximately 1.5 kW (see Figure 3 and Figure 4 below).[42] This is substantially different than the Fig. 2 shown in Jacobs's testimony that reflects back up electric resistance systems for standard heat pumps ranging between 2 kW to 14 kW as temperatures drop below 40 degrees.

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[42] https://publicservice.vermont.gov/sites/dps/files/documents/Energy_Efficiency/Reports/Evaluation%20of%20Cold%20Climate%20Heat%20Pumps%20in%20Vermont.pdf

Figure 3. Comparison of Cold Climate Heat Pump Demand by Temperature (Cadmus 2017)

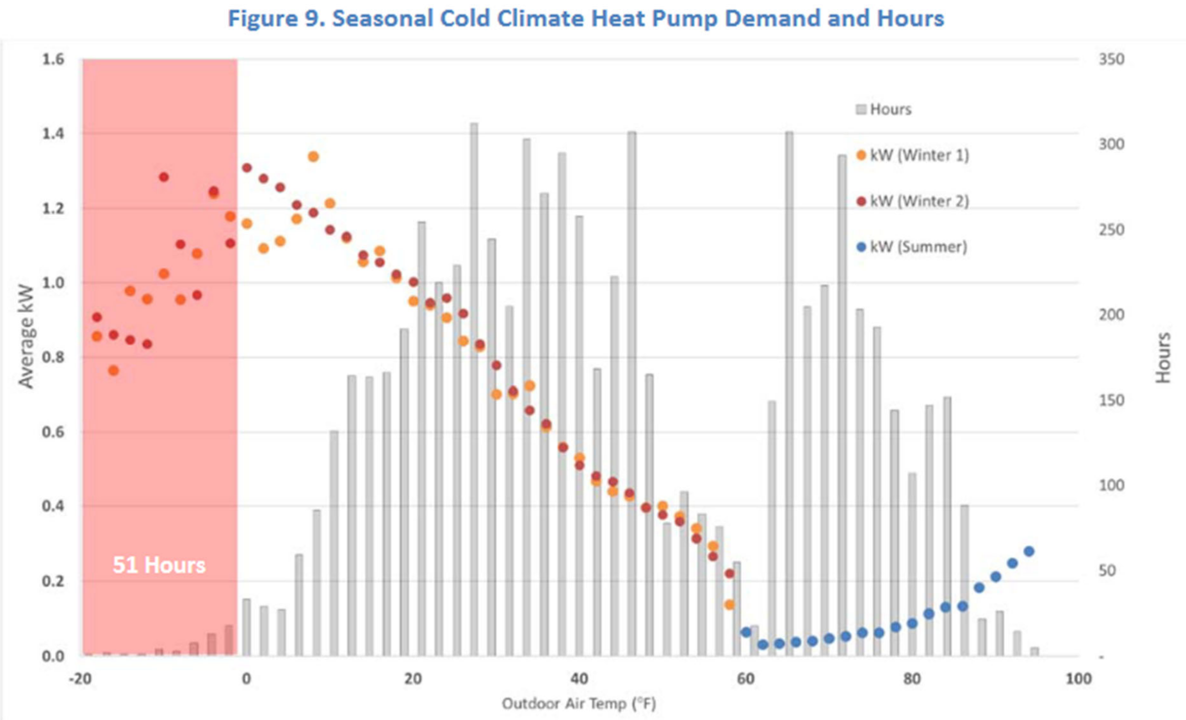
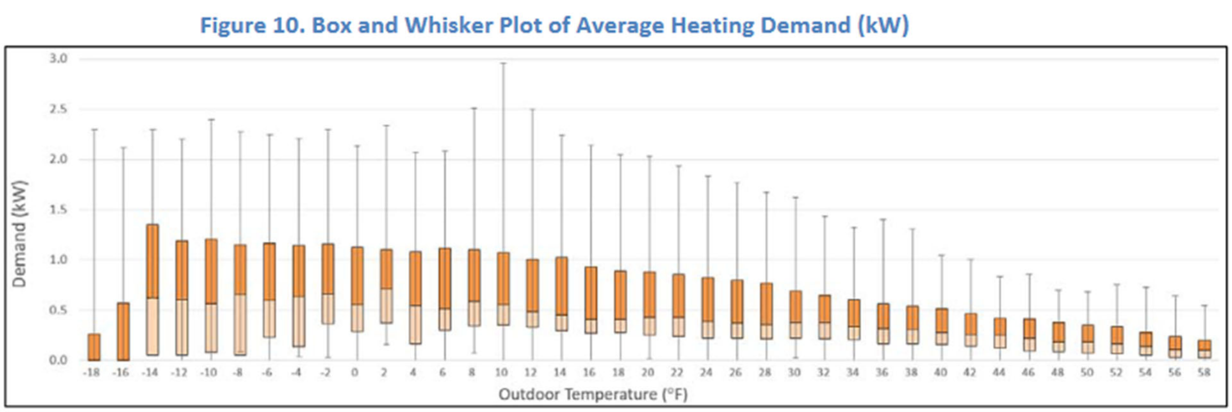


Figure 4. Comparison of Cold Climate Heat Pump Demand by Temperature (Cadmus 2017)



Regarding the impact on winter peak loads, PSE suggests that more expansive electrification would require "major, expedient, and unprecedented expansion of the electric generation, transmission, and distribution infrastructure" (Jacobs p.46), due in part to uncertainty regarding availability of CETA-compliant dispatchable power generation needed for peak conditions. PSE also states its dispatchable electric resources (including transmission and distribution) are sized to meet current demand for electricity. On the power side, this does not reflect naturally occurring and accelerating electrification of buildings and transportation, in particular, that merit improvements in programmatic solutions as well as infrastructure to address increasing electric loads. This assertion also ignores a range of dispatchable resources that have been shown to effectively and reliably address increase peak usage, including demand-side and supply-side options, such as demand response, time-varying rates, and customer-sited and utility-scale storage. It also flies in the face of best practices for electrification programs.

The Biennial Conservation Plan appendix exhibits for cost-effectiveness does not appear to provide discrete costs and savings/production targets for the Hybrid Heat Pump Pilot Program. Under the Residential Pilots, only Retail Choice (estimated savings: 1,005 MWh, 50,250 therms), Single Family AMI Engagement (720 MWh), and HEA Behavioral (0 MWh) are included. The plan includes several other programs with opportunities to replace customer HVAC systems. First, Low Income Weatherization is projected to save 3,954 MWh (total budget of $12.2m), which involves audits with whole-home retrofit opportunities. This is troubling as the proposed hybrid electrification is insufficient as it stands to meet PSE's decarbonization goals and according to its plans, it appears that even this is not sufficiently supported.

Q. What is the relationship between building electrification and existing gas efficiency programs?

A. One area of concern when rolling out building electrification programs is that without clear program guidelines and direction from the utility, trade allies and implementers can receive mixed messages. When a utility continues to provide incentives for gas furnaces alongside heat pumps, trade allies can tend to stick with the technology that they know (and that is often easier to install). Additionally, many gas furnace offerings either directly or indirectly support the installation of standalone air conditioning alongside efficient furnaces. If a utility wants to transition to a heat pump first approach, it's critical that the utility clearly incentivize the desired technology (efficient heat pumps) and not support the competing technologies (gas furnaces, air conditioning). Even under a hybrid electrification approach, air conditioning will need to be eliminated from programs and gas furnace efficiency has substantially reduced value given reduce run-times when only acting as back-up heat source to a heat pump.

CONCLUSIONS AND RECOMMENDATIONS

Q. What are your conclusions about PSE's GRC filing with respect to grid modernization and distributed energy resources?

A. PSE erroneously treats comprehensive grid modernization as the prerequisite to any full scale deployment of DERs, electrification, or resilience programs. Grid modernization, when thoughtfully planned and integrated, is a critical foundation for the utility of the future. However, there are many examples of utilities in the U.S. and abroad that have successfully enabled very large penetration of DERs without the tools PSE proposes here, so I disagree that all of PSE's proposed grid modernization capital expenditures are necessary or attributable to CETA. Moreover, rolling out grid modernization is an iterative process that should be driven by current and anticipated needs. PSE claims that its proposed investments in grid modernization here are often cited as driven by policy objectives, while neglecting how far behind its peers PSE currently is. For instance, while PSE argues that enabling technologies like SCADA or operational analytics across its full distribution system is driven by CETA, in reality, it is merely PSE catching up to best practice for a utility of its size. Additionally, PSE proposes to jump from fundamental investments, such as AMI and SCADA, directly to cutting edge technologies such as Distributed Energy Resource Management Systems (DERMS), Virtual Power Plants (VPPs), and microgrids. It's hard to imagine how that transition could happen so quickly when there has been so little progress to date. While I'm supportive of fundamental investments, I would advise caution in approving so many when they appear to be so decoupled from actual outcomes, such as increased DER adoption, electrification, resilience, reliability, and/or cost reductions.

Q. What are your conclusions about PSE's GRC filing with respect to demand response?

A. Despite years of pageantry and process, PSE still fails to demonstrate a sincere effort on demand response consistent with its regional peers and the industry as a whole. PSE has set a target of 23.7 MW of demand response across a portfolio of programs. This target is so small that it could potentially be met with a single industrial customer in some service territories. The nationwide average contribution of demand response to system peak is 6%, while despite nearly a decade of planning and RFPs, PSE is only proposing to acquire less than 0.5% of its peak load. There are many factors at play here, including conservative valuation of the peak contribution of DR with its very low ELCCs, including only programs for mass market (residential/small commercial customers), lack of integration of demand response within its broader program portfolio, and lack of dynamic rates. PSE has rightly argued in the past that lack of maturity in the NW market and having a winter peaking system make it harder to acquire DR in the region. However, this argument is more difficult to accept after over 10 years of DR program growth amongst its peer utilities and recent findings from the Northwest Power Plan and BPA that show an abundance of cost-effective winter DR in the region (Exh. JBK-4). PSE's own DER RFP showed 160 MW of Tier 1 demand response available today, even with the conservative economics put forward by the utility. Especially with an IRP stating increased capacity needs and their gas decarbonization study raising the specter of even greater peaks in the future (driven by growth in highly controllable loads like space and water heating), PSE needs to quickly acquire dramatically more DR to meet its carbon goals cost-effectively, especially when it is requesting so much capital for grid modernization and enablement.

Q. What are your conclusions about PSE's GRC filing with respect to time varying rates?

A. PSE should accelerate widespread deployment of TVR. Time-varying rates were identified both by the UTC and in PSE's own research as one of the highest value use cases for AMI, yet PSE does not plan to deploy them until 2027 despite their proposed design. In 2022, when the other major investor-owned utilities in the region already have time-varying rates offered at scale and California has them rolled out on an opt-out basis across their residential customers, PSE should not be requesting nearly five years to pilot opt-in program designs that are wildly in use around the country. The need for evaluation is of course important, but the incremental value of a slightly more effective experimental design should not be used as an excuse to dramatically delay achieving value from AMI and helping to lower the costs of decarbonization. PSE should be deploying these programs to the broader population now, perhaps with low-income customer protections and a commitment to evaluate and adjust their design as necessary on an ongoing basis (as is common practice for DSM programs today). If PSE would like to conduct more experimental pilots, these should be reserved for more innovative or risky designs, such as real-time rates, demand charges, or opt-out TOU/PTR offerings.

Q. What are your conclusions about PSE's GRC filing with respect to electrification and gas decarbonization?

A. PSE eschews the need to electrify buildings, instead insisting on only partial electrification of buildings, claiming that increased electric winter peaks will be too costly to manage. However, PSE makes this claim while not considering modern heat pump technologies, learning curves for heat pump technologies, increasing natural gas prices, synergies with weatherization programs and building codes, use of thermal or electric storage onsite, or co-deployment of resources with flexible load benefits (e.g., demand response) with electrification measures. Doing so presupposes a program design approach out of step with best practices and seems to take a biased view of where technology costs will improve, assuming electrolyzers and renewable methane production will become more cost-efficient while heat pump costs will stagnate. This approach leads to findings that are inconsistent with the growing consensus in the deep decarbonization literature in the Northwest and nationally that recognizes that full building electrification is one of the most critical tools for decarbonization of the energy sector, while also improving public health outcomes and decreasing energy burden. Electrification should be included as part of a comprehensive strategy to manage flexible load, providing opportunities for synergies with weatherization programs and building codes, energy storage, and co-deployment of demand response measures with electrification measures.

PSE's gas decarbonization efforts show merit as a preliminary concept in improving lifecycle emissions by blending renewable natural gas and, to a lesser extent, hydrogen, into existing pipelines. These gas decarbonization investments, covered through both voluntary programs and broad-based ratepayer funded programs, may eventually become key elements to help PSE meet its decarbonization goals. However, by PSE's own admission, these investments are expected to grow exorbitantly expensive at higher quantities and remain largely unproven at the level of scale suggested in the exhibits sponsored by PSE witness Joshua Jacobs. PSE's studies (provided as exhibits to Jacobs's testimony). If PSE is serious about decarbonizing this portion of its business, it should put forward a more comprehensive plan that incorporates integrated distribution planning and asset management, to answer key questions such as what types of fuels can be injected on which parts of the grid and where can PSE strategically prune its distribution networks using electrification.

Q. Based on the above testimony, what are your recommendations?

A. Based on my review and analysis of PSE's proposed investments in DERs and electrification, I recommend the following:

Grid modernization and distributed energy resources:

- The following grid modernization investments should have no portion attributed to CETA because the company has not demonstrated how these are specifically related to CETA requirements, as opposed to simply bringing the utility in line with best practices:
    - Hosting Capacity Analysis ($9.62m attributed to CETA);
    - Data Lake and Analytics ($3.65m attributed to CETA);

- Substation SCADA – Accelerated ($41.36m attributed to CETA).

- Further, the Circuit Enablement-DER and Microgrid investment of $57.5m should be removed from the revenue requirement request in this proceeding and discussed at a later date, through either the CEIP proceeding or another forum. The company has not made a compelling case for the need for this substantial investment, explained how the company would select circuits for Investment, and/or explained how this project would differ from upgrades typically incurred through customer interconnection costs.
- PSE should not be allowed to recover costs for its $9 million investment in VPP without substantially higher targets for demand response and demonstrated reasonable progress toward achieving those targets.

Demand response and time varying rates:

- PSE should be required to acquire at least 160 MW of demand response, with offerings to all customer segments, including large commercial and industrial.
- PSE should be required to adjust its plan for deploying dynamic rates such that all residential and small commercial customers are eligible to participate at the onset. This should include a revised budget, detailed justification for any changes to capital expenditures, and a revised EM&V plan.

Electrification and gas decarbonization:

- PSE should integrate transportation costs into future Energy Burden Analyses to ensure a more complete picture of how it can affect customer vulnerability to different energy costs.
- PSE should update its gas decarbonization analysis to include:
    - Revised gas price forecasts incorporating new structural volatility;

- Integration of accompanying EE and DR into deployment of electric end uses;
- Incorporation of heat pump learning curves for standard and cold climate heat pumps;
- Assumptions around naturally occurring air conditioning growth driven by customer preference and increasing summer temperatures;
- Exploration of options that include integration of distributed thermal and/or electric storage with electrification; and
- Identification of cost savings for avoided and/or decommissioned gas distribution infrastructure.

- PSE should incorporate findings from its revised gas decarbonization study to develop a building electrification plan. This plan should propose a series of electrification measures that can be co-deployed with its energy efficiency, demand response, and DER programs to achieve cost-effective decarbonization of its gas system.
- PSE should commit to review its gas heating incentives in consultation with its advisory groups in light of new compliance obligations for its gas business. This review should include consideration of replacing gas heating incentives with HP incentives (or at a minimum, deny incentives to gas furnaces that are installed with AC instead of HP) and work to transform the market as their own analysis indicates this is a highly effective way to decarbonize their gas system and contributes to electric efficiency.
- PSE should explicitly integrate forecasts of building electrification into their load forecasts and revenue requirements analysis for both their gas and electric customers.
- PSE should adjust the Peak Load Management PIM to be assessed on ELCC of demand response achieved, not simply coincident winter peaking value.

- PSE should commit to discouraging the deployment of standalone air conditioning with their contractors and require any incentivized installations of HVAC equipment to use heat pumps for cooling to ensure consistency with its stated goals around electrification.

Q. Does this conclude your testimony?

A. It does.