BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

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<tr><td>WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY,

Respondent.</td><td rowspan="2">DOCKETS UE-220066/UG-220067 and
UG-210918 (Consolidated)

SETTLEMENT STIPULATION AND
AGREEMENT ON REVENUE
REQUIREMENT AND ALL OTHER
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<tr><td>In the Matter of the Petition of

PUGET SOUND ENERGY

For an Order Authorizing Deferred
Accounting Treatment for Puget Sound
Energy’s Share of Costs Associated with the
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AUGUST 26, 2022
SETTLEMENT STIPULATION AND AGREEMENT ON
REVENUE REQUIREMENT AND ALL OTHER ISSUES EXCEPT
TACOMA LNG AND PSE’S GREEN DIRECT PROGRAM

CONTENTS

I. INTRODUCTION

1. This Settlement Stipulation and Agreement addresses all issues in Puget Sound Energy's ("PSE" or "the Company") above-captioned general rate case except those issues relating to the Tacoma Liquified Natural Gas ("LNG") Facility and those related to the Settlement Stipulation and Agreement (Green Direct) [1] ("Settlement"). The Settlement is entered into by and between the following parties in this case: (i) PSE, (ii) the regulatory staff of the Washington Utilities and Transportation Commission ("Commission Staff"),[2] (iii) Alliance of Western Energy Consumers ("AWEC"), (iv) Federal Executive Agencies ("FEA"), (v) Walmart, Inc. ("Walmart"), (vi) The Energy Project, (vii) Kroger, Co. ("Kroger"), (viii) NW Energy Coalition, (ix) Sierra Club, (x) Front and Centered, (xi) Microsoft and (xii) Nucor Steel Seattle, Inc. ("Nucor"), as of August 26, 2022. These parties are hereinafter collectively referred to as "Settling Parties" and individually as a "Settling Party."

2. This Settlement is a partial multiparty settlement as that term is defined in WAC 480-07-730(3)(b).

3. King County neither joins nor opposes the Settlement.

4. The Coalition of Eastside Neighborhoods for Sensible Energy ("CENSE") opposes the Settlement.

[1] Issues relating to the Tacoma LNG facility and PSE's Green Direct Program are addressed in separate settlement stipulations. This stipulation incorporates the Green Direct settlement stipulation's Green Direct credit term into its agreed revenue requirement increase. *See* Section III.A, *infra*.

[2] In formal proceedings, such as this, the Commission's regulatory staff participates like any other party, while the Commissioners make the decision. To assure fairness, the Commissioners, the presiding administrative law judge, and the Commissioners' policy and accounting advisors do not discuss the merits of this proceeding with the regulatory staff, or any other party, without giving notice and opportunity for all parties to participate. See RCW 34.05.455.

5. The Public Counsel Unit of the Washington Office of the Attorney General ("Public Counsel") will respond to the Settlement on September 9, 2022, and may support or remain neutral regarding most terms, except cost of capital and capital structure.

6. To the extent appropriate given the limitations placed on its involvement in this case, the Puyallup Tribe of Indians may respond to this Settlement on September 9, 2022, indicating its support, opposition and/or neutrality regarding Settlement terms.

7. This Settlement is subject to review and disposition by the Washington Utilities and Transportation Commission ("Commission"). Section III of the Settlement is effective on the date of the Commission order approving it (unless the Commission establishes a different effective date). The remainder of the Settlement is effective as of August 26, 2022.

II. BACKGROUND AND NATURE OF THE DOCKET

8. On January 31, 2022, PSE filed with the Commission, in Dockets UE-220066 and UG-220067, a general rate case ("2022 GRC"), which proposed a three-year multiyear rate plan ("MYRP").

9. On February 10, 2022, the Commission suspended operation of the as-filed tariff schedules, commenced discovery, and set the matter for hearing in Order 01.

10. On February 28, 2022, the Commission convened a virtual prehearing conference. The Commission granted party interventions and set a procedural schedule in the Prehearing Conference Order, served on March 3, 2022.

11. On April 27, 2022, Commission Staff filed a motion to consolidate an accounting petition PSE filed in Docket UG-210918, seeking an order authorizing deferred accounting

treatment for PSE's share of costs associated with the Tacoma LNG Facility, with the 2022 GRC. On May 12, 2022, the Commission consolidated the proceedings.

12. On July 28, 2022, Commission Staff, Public Counsel, and Intervenors filed response testimony.

13. The parties to PSE's general rate case participated in several virtual settlement conferences, including on June 13, 14, and August 10 and 12, 2022. In addition, settlement discussions continued by email during this time period.

14. On August 5, 2022, a partial multiparty settlement on the Green Direct program was filed with the Commission, along with supporting testimony. The parties to that settlement are PSE, Commission Staff, Public Counsel, King County, and Walmart. No party opposes the Green Direct settlement.

15. On August 12, 2022, the parties notified the Commission that two settlements in principle had been reached: one that specifically addressed Tacoma LNG issues and a second settlement that addressed all other remaining issues in the case (this Settlement).

16. On August 18, 2022, Nucor agreed to join the settlements in principle reached on August 12, 2022.

17. On August 18, 2022, the Commission convened a Status Conference to discuss a schedule for filing settlement documents and testimony supporting and opposing the settlements.

18. On August 22, 2022, the Commission issued a revised procedural schedule for the Settlement hearing.

III. AGREEMENT

19. The Settling Parties agree to the following terms as a multiparty settlement in this filing that fully settles all issues in this proceeding except those relating to Tacoma LNG and

Green Direct. Supporting Schedules are presented as exhibits to this Settlement Stipulation and Agreement.[3]

A. Revenue Requirement and Prudence

20. Two Year MYRP. The Settling Parties agree to a two-year MYRP.

21. Electric Revenue Requirement. The Settling Parties agree to an overall electric revenue increase of $223 million in the first year of the rate plan and an overall electric revenue increase of $38 million in the second year of the rate plan.

22. Gas Revenue Requirement. The Settling Parties agree to an overall natural gas revenue increase of $70.6 million in the first year of the rate plan and an overall natural gas revenue increase of $18.8 million in the second year of the rate plan.

23. The Settling Parties agree the revenue requirement increases assume and reflect the following assumptions:

a. Return on Equity/Capital Structure/Cost of Debt. The authorized return on equity is set at 9.4 percent and the capital structure is set at 49 percent equity/51 percent debt with the cost of debt at 5.0 percent for the duration of the MYRP.

b. Reliability Spending. $70 million of electric and natural gas reliability spending that PSE projected to spend in 2023 is shifted to 2024.

c. Renewable Natural Gas. Renewable natural gas costs are not included.

d. Power Costs. Power cost increases embedded in the revenue requirement are assumed to equal PSE's filed case ($125.5 million in 2023) reduced for the

[3] Exhibits A-N are attached. Workpapers will be provided to the Settling Parties.

electric portion of the Northwest Pipeline settlement ($4.6 million, after grossing up for revenue sensitive items). The power cost update that will occur at the compliance filing in this case[4] will use these power costs as the reference point for projected 2023 power costs.

e. Advanced Metering Infrastructure ("AMI"). The Settling Parties accept a determination that:

    i. PSE has adequately demonstrated utility system benefits of AMI.

    ii. PSE will continue deferring recovery of its return on equity on AMI but will recover its debt component of return on rate base.

        1. On AMI plant in service as of December 31, 2019, PSE will defer through 2022 its return on rate base (equity and debt) per Order 08 in Dockets UE-190529 and UG-190530. Beginning in 2023, PSE will amortize over three years the debt component of return on rate base that has been deferred through 2022 on investments made as of 2019.

        2. As of January 1, 2023, the deferral of the return on equity on AMI plant will include plant as of December 31, 2021, and PSE will amortize the debt component of return on rate base deferred through 2021 over three years beginning in 2023.

        3. The deferral of the return on equity component of AMI will continue until rates are changed in PSE's next MYRP, and the

[4] *See* Section III.D. *infra.*

amortization of deferred return on equity on AMI investments may not occur sooner than 2025.

iii. PSE is entitled to recovery of its AMI plant put into service through December 31, 2021, to the extent not already recovered.

iv. Parties do not object to the Commission making a determination that costs (depreciation and the debt component of return on investment) for AMI after December 31, 2021, are reasonable, subject to refund, pending future review processes.

v. PSE will not receive a final determination of prudency on the AMI project until the AMI installation is complete and PSE provides an AMI benefits progress report. PSE will file a final AMI benefits progress report as a compliance filing in these dockets no later than the filing of its next MYRP. The report will provide an update describing how PSE has continued efforts to maximize Company and customer benefits realized under the program and PSE's plans to continue such maximization efforts, as well as any new Company or customer benefit use cases identified.

vi. In the AMI benefits progress report, PSE will update its AMI reporting metrics, including equity considerations.

f. Electric Capital Investments. The Settling Parties agree that PSE's proposed electric capital investments will be included in its proposed MYRP rates with reductions noted elsewhere in this Settlement. As discussed below, PSE will propose to recover certain capital expenses related to its Clean Energy

Implementation Plan ("CEIP") and Transportation Electrification Program ("TEP") through separate trackers.[5]

g. Gas Capital Investments. The Settling Parties agree that PSE's proposed gas capital investments will be included in its proposed MYRP rates with revenue requirement reductions of $5 million in 2023 and $1 million in 2024 to reflect lower gas rate base in part to be attributable to lower new gas customer construction costs.

h. Electric Operations and Maintenance ("O&M"). The Settling Parties agree to PSE's proposed increases to electric O&M with reductions embedded in Exhibit J to this Settlement. As discussed below, PSE will recover certain O&M expenses related to its CEIP and TEP through separate trackers.[6]

i. Gas O&M. The Settling Parties agree to PSE's proposed increases to gas O&M with a 20 percent reduction in the gas O&M increases in 2023 and 2024.

j. Colstrip. PSE will move Colstrip rate base and expense into a separate tracker under Schedule 141-C, as proposed in the testimony of Susan E. Free (Exh. SEF-18). PSE agrees to exclude capital investments associated with the construction of PSE's Colstrip dry ash facilities from recovery in base rates in this case and PSE's proposed Schedule 141-C tracker. The Settling Parties agree that Colstrip costs included in rates in 2023 and beyond (including major maintenance expense and new plant additions) are subject to review,

[5] *See* Section III.A, *infra* (the section detailing revenue requirement assumptions, subsections k and l).
[6] *See id.*

including but not limited to an examination of prudence, in PSE's annual Schedule 141-C tariff filing. Major maintenance costs incurred during the MYRP will be amortized over three years, regardless of the year incurred. Costs amortized after 2025 would not be recovered in rates. The Settling Parties retain all rights to challenge Colstrip costs when PSE files tariff revisions for the tracker.

k. Clean Energy Implementation Plan. PSE agrees to develop a separate tracking mechanism and tariff (“Schedule XX, Clean Energy Implementation Tracker”) for costs included in its approved CEIP in Docket UE-210795 that are not included in Power Costs and are appropriate for recovery during the MYRP. Such costs may include but are not necessarily limited to distributed energy resource (“DER”) program costs, O&M expense, and capital expense for projects that enable CEIP implementation. The Settling Parties agree to work collaboratively with PSE in developing this tracker by April 1, 2023. All CEIP investments recovered through this separate tracking mechanism are subject to review, including but not limited to an examination of prudence. This tracker will expire upon the implementation of new rates in PSE’s next general rate case, or other date agreed to by the Settling Parties. This proposal is non-precedential, and inclusion of costs in the tracker does not qualify them as incremental costs for the purpose of WAC 480-100-660(4). PSE agrees to include costs associated with its 2025 CEIP as part of base rates or the associated tariff schedules implementing PSE’s MYRP (i.e., Schedules 141-N and 141-R) in its next general rate case.

l. Transportation Electrification. The Settling Parties agree to move recovery of Transportation Electrification Program ("TEP") costs to a new rate tracker. Such costs will include capital, depreciation, and O&M expenses to enable the TEP. The Settling Parties have no position as to whether this approach to recovery of TEP costs would be permanent or not. The Settling Parties retain all rights to challenge program costs when PSE files tariff revisions for the tracker.

m. Energize Eastside. The Settling Parties agree that delayed service dates for Energize Eastside are assumed to be incorporated into the agreed upon revenue requirement above (i.e., South Phase in service by October 2023 and North Phase in service by October 2024). The Settling Parties agree that estimated costs associated with Energize Eastside (as described in PSE's initial filing) may enter rates provisionally (on the updated timeline, outlined above), subject to refund. Settling Parties accept and will not challenge that PSE has met its threshold prudence requirement to demonstrate that the investment should be provisionally included in rates. Settling Parties may challenge the costs of the project in the review of investments after the plant is placed in service.

n. COVID Deferral. PSE agrees to a partial write-off of the COVID deferral. Deferred costs, savings, and fee revenues associated with PSE's COVID deferred accounting petition filed in Dockets UE-200780 and UG-200781 will be written-off, but PSE can seek to recover its "Additional Funding for Customer Programs" provided by PSE in compliance with Order 01 in Docket

U-200281 and bad-debt accrued in excess of levels embedded in existing rates through PSE's electric and gas Schedule 129.

o. Load Forecast. PSE agrees to change the load forecast for certain rate schedules. [7]

p. Plant Investment. The Settling Parties do not object to determination of prudence for all other plant investment through 2021 as proposed in PSE's direct case. The Settling Parties do not object to allowing to go into rates all other plant investment included in PSE's MYRP that went, or is projected to go, into service in 2022 through 2024 subject to refund and the annual review process for prudence proposed in the testimony of Susan E. Free (Exh. SEF-1Tr).

q. Depreciation Rates and Expenses. The Settling Parties accept PSE's proposed depreciation rates and expenses as proposed by Ned W. Allis (Gas and Common from Exh. NWA-3 and Electric from Exh. NWA-4) and Susan E. Free (Exh. SEF-1Tr).

r. Regulatory Assets

    i. Automated Meter Reading. The Settling Parties do not object to PSE's recovery of its AMR investment.

    ii. Water Heater Business. The Settling Parties do not object to PSE's recovery of its loss associated with its water heater business sale.

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[7] *See* Section III.F, *infra*.

iii. Other Regulatory Assets and Liabilities. The Settling Parties do not object to PSE's proposals related to all other regulatory assets and liabilities, as identified in Exhibit N to the Settlement Agreement.

s. Green Direct. The recovery of the Green Direct Energy Credit is included in the proposed electric revenue requirement in this Settlement.

t. Other Revenue: PSE will remove from the Gas revenue requirement model the "Other Adjustments" in column I, line 28, on p. 1, of Exh. JDT-3. PSE will remove from the Electric revenue requirement model the "Other Adjustment" in column (b), line 24, on p. 2, of Exh. BDJ-3.

u. Estimated Residential Bill Impacts: The estimated bill impacts resulting from this Settlement for residential electric and gas customers is shown below. PSE will make a subsequent filing by September 2, 2022 with updated bill impacts for electric and gas customers.[8] Final electric impacts will not be known until the power cost update is completed in the compliance filing.

Electric		
Settlement Average Bill Increase		
Rate Class	**2023**	**2024**
Residential Sch 7	$ 10.83	$ 1.71

Gas		
Settlement Average Bill Increase		
Rate Class	**2023**	**2024**
Residential (16,23,53)	$ 4.93	$ 1.27

[8] Final cost of service numbers may impact net revenue change included in the revenue requirement exhibit for both electric and gas.

v. Estimated Percent of Revenue Increase by Rate Class: The below is an estimate of the percent of total revenue increase by rate class, resulting from the Settlement, for electric and gas customers. PSE will make a subsequent filing by September 2, 2022 with updated percent of revenue increase by rate class for electric and gas customers.[9] Final electric revenue increase will not be known until the power cost update is completed in the compliance filing.

Electric		
Settlement % of Total Revenue Increase by Rate Class		
Rate Class	**2023**	**2024**
Residential Sch 7	11.4%	1.6%
Sec Volt Sch 24 (kW< 50)	7.8%	1.3%
Sec Volt Sch 25 & 29 (kW > 50 & < 350)	8.7%	1.4%
Sec Volt Sch 26 (kW > 350)	7.2%	1.3%
Pri Volt Sch 31 (General Service)	7.7%	1.4%
Pri Volt Sch 35 (Irrigation)	21.8%	2.4%
Pri Volt Sch 43 (Interruptible)	5.5%	1.1%
Special Contract	-1.9%	1.6%

[9] Final cost of service numbers may impact net revenue change included in the revenue requirement exhibit for both electric and gas

High Volt Sch 46 & 49 (Interruptible & Gen Svc)	2.0%	1.1%
Choice/Retail Wheeling Sch 449 & 459	1.2%	0.2%
Street & Area Lighting	15.4%	2.1%
Total	**9.7%**	**1.5%**

Gas		
Settlement % of Total Revenue Increase by Rate Class		
Rate Class	**2023**	**2024**
Residential (16,23,53)	6.5%	1.6%
Comm. & Indus. (31,31T)	6.2%	1.6%
Large Volume (41,41T)	5.8%	1.5%
Interruptible (85, 85T)	10.7%	2.6%
Limited Interruptible (86, 86T)	2.1%	0.7%
Non-Exclusive Interruptible (87, 87T)	4.4%	1.4%
Contracts	-0.5%	0.0%
Total	**6.4%**	**1.6%**

w. Estimated Percent of Margin Increase by Rate Class: The below is an estimate of the percent of total margin increase by rate class, resulting from the Settlement, for gas customers. PSE will make a subsequent filing by

September 2, 2022 with updated margin increase by rate class for gas customers.[10]

Gas		
Settlement % of Margin Increase by Rate Class		
Rate Class	**2023**	**2024**
Residential (16,23,53)	12.8%	3.3%
Comm. & Indus. (31,31T)	13.6%	3.7%
Large Volume (41,41T)	14.3%	3.8%
Interruptible (85, 85T)	19.1%	5.2%
Limited Interruptible (86, 86T)	6.4%	2.2%
Non-Exclusive Interruptible (87, 87T)	11.6%	3.7%
Contracts	-0.6%	0.0%
Total	**13.1%**	**3.5%**

B. Corporate Capital Planning

24. By the end of the MYRP, the Settling Parties agree PSE shall make a compliance filing in these dockets demonstrating:

a. Plan for Equitable Outcomes. A process or procedure for how PSE's Board of Directors and senior management plan for equitable outcomes when making decisions on enterprise-wide capital portfolios within the three-tier planning process. This will include a transparent and inclusive methodology for how the Enterprise Project Portfolio Management ("EPPM") tool will be used to

[10] Final cost of service numbers may impact net revenue change included in the revenue requirement exhibit for both electric and gas.

apply an equity lens to the Corporate Capital Allocation framework that integrates feedback from persons affected by PSE's decisions.

b. Corporate Spending Authorizations ("CSAs"). PSE's use of CSAs that require sponsors to consider the equitable distribution of benefits and reduction of burdens of the project or program. This can be demonstrated either qualitatively or quantitatively, or both. Once the Company has completed its pilot distributional equity analysis, participated in the Commission Staff-led process,[11] and has received approval from the Commission for its methods (and updated its analysis as necessary to conform to any changes to methods potentially required by the Commission), PSE will include in its CSAs results of distributional equity analysis.

C. Delivery and Distribution System Planning

25. Distribution System Planning. PSE will conduct Distribution System Planning in coordination with its CEIP process, as part of an integrated system planning approach for distribution system investments. A goal of the Distribution System Plan is identifying ways that connected customer-side resources can provide system value for all customers and achieve an equitable distribution of benefits and burdens to vulnerable populations and highly impacted communities. During the MYRP, PSE will solicit stakeholder input to help identify options and priorities for community-based resources and provide equitable treatment of measures that can enhance distribution carrying capacity, including those not owned or controlled by PSE.

[11] *See* section III.L. *infra*.

26. Investment decision optimization tool ("iDOT"). PSE will develop new benefits and costs (with associated weights) related to equity for use in the optimization step in its replacement software for iDOT.

a. PSE must, at minimum, collaborate with its Equity Advisory Group, Integrated Resource Plan ("IRP") Advisory Group, and its customers, particularly in Named Communities. Engagement with these groups will occur at least at the "Collaboration" level on the International Association for Public Participation Spectrum.[12]

b. New benefits and costs in the iDOT should include, but are not limited to, societal impacts, non-energy benefits and burdens, and the Social Cost of Greenhouse Gases, as well as any other benefits and costs deemed appropriate after engagement with PSE's advisory groups.

c. PSE will establish a process for including new iDOT benefits and costs within the Solutions Assessment of projects.

d. Once PSE has completed its pilot distributional equity analysis, participated in the Commission Staff-led process,[13] and has received approval from the Commission for its methods (and updated its analysis as necessary to reflect the approved methods), PSE will incorporate such analyses as a decision-making tool alongside the Benefit/Cost Analysis ("BCA"), which is currently performed in the Optimization step and the Alternatives and Solutions Analysis step.

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[12] International Association for Public Participation Spectrum USA, IAP2 Public Participation Spectrum, available at https://iap2usa.org/cvs.

[13] *See* section III.L. *infra*.

D. Power Costs

27. Power Cost Only Rate Case ("PCORC"). PSE agrees to a PCORC stay-out throughout the pendency of the MYRP. The Settling Parties reserve the right to challenge whether PSE's ability to file PCORCs as allowed under its Power Cost Adjustment ("PCA") Mechanism should continue in future proceedings.

28. Power Cost Updates. The Settling Parties agree that:

a. PSE will update power costs for recovery in 2023 as part of its compliance filing at the conclusion of this case and include the bulleted items listed in subpart b, below, as part of the power cost update.

b. PSE is required to file a 90-day compliance filing in this proceeding to change rates effective January 1, 2024, for power costs to be recovered in 2024. In this compliance filing, PSE will update the rate recovering the PCA baseline by updating the power cost model from this filing with the cost and inputs listed below:

- Costs associated with Mid-C hydro contracts;
- Costs associated with upstream pipeline capacity;
- Outage schedules;
- BPA rates;
- Load forecast (for the 2024 update);
- Variable O&M costs;
- Impacts to dispatch logic related to Climate Commitment Act ("CCA") compliance;
- Hedges and physical supply contracts;
- Natural gas prices;
- Changes to terms of current resources;
- Any new and updated resources (including transmission contracts);
- Nothing in this agreement limits the Settling Parties' ability to review and contest prudence in future proceedings.

29. Timing. By August 1, 2023, PSE must provide details regarding any complex changes to the PCA baseline rate including work papers demonstrating the method and effect of the changes. If there are no complex changes, PSE must provide a letter stating so. Complex changes include, but are not limited to:

- Any new power resources;
- Any new contracts (e.g., transmission);
- Modification in any existing contract structure or form;
- Any methodological changes to PSE's power cost calculations.

a. The Settling Parties agree that by October 1, 2023, PSE must provide all other changes to the forecast.

b. The compliance filing containing proposed rates to recover the new PCA baseline rate would be made by PSE with sufficient time for Commission Staff to review in order to become effective on January 1, 2024.

30. Prudence. Any new resources included in the January 1, 2023 or January 1, 2024 baseline update will undergo a prudency review in the annual PCA Compliance Filing. To reduce the amount of time that costs spend in deferral, the prudence of any new resources effective in 2023 will be determined in the April 2023 PCA filing. Prudence of any new resources effective in 2024 will be determined in the April 2024 PCA Compliance Filing.

a. The Settling Parties reserve the right to recommend to the Commission that a prudence determination of a particular resource occur in the following year.

b. The Settling Parties reserve the right to challenge actual deferrals in the following year's PCA Compliance Filing.

31. Power Supply Resources. The Settling Parties accept that all power supply resources (including transmission contracts) for which PSE sought a prudence determination in its initial 2022 GRC filing are deemed prudent.

32. DER Power Purchase Agreements ("PPA"). The cost of any DER PPA for distributed generation, battery resources and demand response costs are eligible for recovery through PSE's PCORC, PCA Mechanism and/or annual power cost update and are eligible for potential earning on PPAs pursuant to RCW 80.28.410.

E. Rate Spread

33. Electric. The Settling Parties accept PSE's filed rate spread methodology in the testimony of Birud D. Jhaveri (Exh. BDJ-1Tr).

34. Gas. The Settling Parties agree to a gas base rate spread that is midway between PSE's proposed relative percentage-based increases in the testimony of John D. Taylor (Exh. JDT-1T) and an equal percent of margin. The Settling Parties agree to spread Schedules 141-R and 141-N proportionately to the base increase.

F. Rate Design

35. Electric. The Settling Parties agree to:

a. No increase to residential basic monthly charge.

b. Increase the account limit for the conjunctive demand service option from 5 to 15 accounts per customer and increase the customer's participating load limit to 6 MW of winter demand. To accommodate increased load in this program, PSE agrees to increase the cap on the program size from 20 aMW to 30 aMW.

c. For all rate schedules with demand-based charges, the rate design of the MYRP riders (Schedules 141-R and 141-N) should include both a demand

and an energy component for each rate schedule that includes both a demand and an energy charge in its base rates. The amount of rider costs collected through the demand and energy charge components for each rate schedule should be proportional to the demand and energy charge revenues that are collected through base rates for each rate schedule. The Settling Parties agree that the proportion of costs to be recovered through the demand and energy charges would be tied to the projected proportion of base revenue in 2023, as actual results are unlikely to vary greatly and this would avoid the need to track/true-up for small differences between the projected proportionality and actual results.

d. For all rate schedules with demand-based charges, the rate design of the Colstrip rider (Schedule 141-C) is as follows: 80 percent of the revenue will be recovered through demand charges and 20 percent of the revenue will be recovered through energy charges.

e. The Settling Parties agree to split the difference (meet halfway) between PSE's electric forecasted billing determinants and Public Counsel's forecasted billing determinants for three specific rate schedules (Residential – Rate 7, Secondary Pumping/Irrigation – Rate 29, and High Voltage Interruptible – Rate 46). PSE will incorporate changes in loads associated with these changes to billing determinants into its updates to power costs during the rate plan.

36. Gas. The Settling Parties agree to:

a. The basic charge as proposed by PSE witness John D. Taylor (Exh. JDT-1T), with the exception that the residential customer basic charge be $12.5 per month.

b. The Schedule 87/87T charges as proposed by PSE witness John D. Taylor (Exh. JDT-1T), except as modified below:

   i. Demand charge remains unchanged at $1.45 per therm.

   ii. First through fifth base rate volumetric block rates receive an equal percentage increase. Sixth volumetric block rate will receive 33 percent of the average rate increase across base rates.

   iii. Schedules 141-R and 141-N rates are proportional to volumetric base rate increase.

   iv. Calculate rates using test year weather normalized actual volumes and blocking in both rate years plus PSE's filed Puget LNG forecast in corresponding years.

G. Low Income Issues

37. Bill Discount Rate ("BDR") and Arrearage Management Plan ("AMP"). The Settling Parties agree that:

a. PSE will consult with the Low-Income Advisory Committee ("LIAC") to develop and design the BDR and AMP. By July 1, 2023, PSE will make a subsequent filing with the Commission for approval of the BDR and AMP program design developed through the LIAC process.

b. The BDR program will begin on October 1, 2023, will include at least five income-based discount tiers, and at a minimum offer to serve all low-income customers up to 200 percent of the Federal Poverty Level ("FPL") or 50 percent Area Median Income, whichever is higher. PSE, the LIAC, and Community Action Agencies will evaluate ways to provide bill discounts to customers with incomes between 50 and 80 percent of Area Median Income. PSE's subsequent July 1, 2023 filing will describe this evaluation, including the input of other parties and any proposals presented to the LIAC for providing bill discounts to customers with incomes between 50 and 80 percent of Area Median Income.

c. In consultation with the LIAC, PSE agrees to develop and adopt an AMP as part of an integrated program with BDR and Home Energy Lifeline Program ("HELP") with an effective date of October 1, 2024.

d. The program year for the HELP, BDR, and AMP will be October 1 to September 30.

e. PSE will consult with the LIAC concerning:

    i. eligibility criteria;

    ii. enrollment procedures, including the verification of income using self-attestations;

    iii. how to manage the overlap between the Low-Income Home Energy Assistance Program, HELP, and BDR; and

    iv. how to integrate the BDR with HELP and AMP.

f. PSE will not recover new types of costs in its Schedule 129 tariff riders without first consulting the LIAC and making a subsequent filing for Commission approval.

g. PSE will continue to include Community Action Agencies and other agencies delivering low-income bill assistance programs in LIAC meetings.

h. The Settling Parties agree that there will be joint administration of enrollment by PSE and the Community Action Agencies for BDR and AMP programs.

i. Current agency administrative allowances for bill assistance programs will be maintained, with the level to be revisited after the new BDR program is developed and the costs are better known.

j. BDR and HELP funding will be maintained as separate and independent (except unspent HELP funds, which shall be available to fund the BDR program).

k. The Settling Parties agree to preserve the grant function of HELP and its availability for arrearage assistance.

38. HELP Funding Increase. PSE will increase HELP funding consistent with RCW 80.28.425(2), as amended.

39. Low-Income Conservation and Weatherization.

a. PSE agrees to make a good faith effort to increase weatherization measure incentive amounts in 2022. PSE agrees to work with its Conservation Resources Advisory Group ("CRAG") to survey actual installed measure costs and adjust rebate amounts per survey findings, if warranted, and fully fund all low-income conservation measures shown to be cost-effective with a Total Resource Cost test result of at least 0.667 based on survey results.

b. PSE agrees to extend its current commitment[14] to maintain an annual base funding level for weatherization through the end of PSE's next GRC as follows:

PSE agrees to continue to fund low-income weatherization programs that the low-income agencies inform PSE they can feasibly achieve with an annual base funding level of no less than the amount in PSE's current Biennial Conservation Plan Low-Income Weatherization Programs through the next General Rate Case.

c. Nothing in this Settlement is intended to modify any of PSE's existing obligations to make shareholder contributions for weatherization funding.

40. Credit/Collection. PSE agrees to continue its existing credit and collection processes until the conclusion of the proceeding currently being conducted in Docket U-210800.

H. Time Varying Rates Pilot

41. Time Varying Rates ("TVR") Pilot. The Settling Parties agree to the TVR pilot subject to the following modifications:

a. Include low-income customers up to 200 percent FPL/80 percent Area Median Income.

b. Provide enabling technology to half of the low-income program participants at no cost to the low-income participant, and funded through Schedule 120, and examine the results in the evaluation, measurement, and verification ("EM&V") plan.

c. Provide bill protection to half of the low-income program participants and examine the results in the EM&V plan.

[14] Docket U-210542, Order 01, Appendix A, Commitment 43.

d. Provide for review and comment on recruitment language by the Commission (Consumer Protection Division).

e. Include in the EM&V plan an exit survey that asks customers if they understood their rate.

f. Refresh the rates proposed for the pilot to reflect the electric revenue requirement resulting from this Settlement and the electric cost of service methodology presented in the testimony of Birud D. Jhaveri (Exh. BDJ-1Tr).

42. Proposal for Full Opt in Program. PSE agrees to make a proposal for a full opt-in TVR program for residential customers in its next general rate case.

I. Colstrip Tracker and Decommissioning and Remediation Costs

43. Colstrip Tracker. The Settling Parties agree to the Schedule 141-C Colstrip tracker as described above. The Settling Parties also agree to the proposed time period for the Colstrip Schedule 141-C tracker, as proposed by Susan E. Free (Exh. SEF-18), but the Settling Parties may request up to 90 days for review.

44. Forecasted Decommissioning and Remediation ("D&R"). The Settling Parties accept PSE's calculation of forecasted Colstrip D&R costs, net of monetized Production Tax Credits ("PTCs"), and PSE's proposed allocation factor for purposes of the Microsoft buyout.

45. Microsoft Lump Sum Payment. The Settling Parties accept Microsoft's proposal to pay its obligation in a lump sum following the conclusion of this case, as presented in the testimony of Irene Plenefisch (Exh. IP-1T). This results in an up-front payment from Microsoft to PSE's customers of $407,922.43. Microsoft will satisfy its obligation within 90 days of receipt of a bill from PSE following a final, non-appealable, order in these dockets. PSE retains the risk of an inaccurate forecast and will not allocate any under-recovered amounts from Microsoft to

any other customer class. PSE agrees that in the event that D&R costs exceed the estimates presented in this case, it will not seek recovery from Microsoft or other ratepayers of amounts that would otherwise be allocated to Microsoft. Microsoft agrees that in the event D&R costs are less than the estimates presented in this case, it will not seek reimbursement from PSE or other ratepayers for the amount of its overpayment.

46. Order of Priority for PTCs. The Settling Parties agree to the change in the order of priority for the application of PTCs to the recovery of Colstrip costs, as described in the testimony of Susan E. Free (Exh. SEF-18).

47. Colstrip Annual Report. The Settling Parties agree to move the Colstrip annual report to the annual Colstrip tracker filing, as proposed by Susan E. Free (Exh. SEF-18).

J. Clean Energy Transformation Act-Related Costs

48. The Settling Parties agree that there will be no determination regarding which costs may be included in the projected incremental cost of compliance with the Clean Energy Transformation Act in this docket. The Settling Parties agree that any questions surrounding the projected incremental cost of compliance will be addressed in the ongoing CEIP proceeding in Docket UE-210795, per WAC 480-100-660(4).

K. Gas Line Extension Margin Allowances

49. PSE shall provide the following tariff revisions for natural gas line extension margin allowances in its compliance filing immediately following the issuance of the final order in this case, with effective dates no later than when new state building codes take effect in 2023, January 1, 2024, and January 1, 2025:

a. No later than when new state building codes take effect in 2023, such tariff revisions shall reflect a natural gas line extension margin allowance based on the net present value ("NPV") methodology using a two-year timeframe and updated inputs from this rate case.

b. No later than January 1, 2024, such tariff revisions shall reflect a natural gas line extension margin allowance based on the NPV methodology using a one-year timeframe and the same inputs used in 2023.

c. No later than January 1, 2025, such tariff revisions shall reduce the natural gas line extension margin allowance to zero.

L. Distributional Equity Analysis

50. Pilot Distributional Equity Analysis. PSE agrees to develop methods and process for a pilot distributional equity analysis, by means that could include, but are not limited to, the Company hiring a technical expert, consulting literature, and collaborating with the Settling Parties. The Company will apply the methods developed to its proposed 80 MW of distributed energy resources, as proposed in its 2021 IRP and CEIP, as a pilot, updating the application of these methods to this program as needed upon possible updates to the program. Within 15 months of the approval of this MYRP, PSE will file with the Commission a compliance item documenting the methods and results of the pilot distributional equity analysis. If the proposed 80 MW of distributed energy resources is ultimately not included in the 2021 CEIP's preferred portfolio approved by the Commission, PSE will confer with other interested parties and decide on an alternative program to use for this pilot.

51. Distributional Equity Analysis Process. Following the pilot distributional equity analysis, PSE agrees to participate in a Commission Staff-led process, which will be open to participation from other parties, to refine the methods for a distributional equity analysis. Commission Staff will select a third-party facilitator to support this effort that PSE must hire in

consultation with Commission Staff. At the end of this process, PSE will request Commission approval of its methods for a distributional equity analysis going forward and, when approved, apply these methods as detailed in the Corporate Capital Planning and Delivery System Planning sections of this stipulation.

M. Other Issues

52. Decoupling. The Settling Parties agree to PSE's proposal for electric and gas decoupling discussed in the testimony of Birud D. Jhaveri (Exh. BDJ-1Tr).

53. Annual Review and Earnings Sharing. The Settling Parties agree to PSE's annual review process and earnings sharing proposals discussed in the testimony of Susan E. Free (Exh. SEF-1Tr), except that the review period will be four months.

54. Allocation of CEIP/TEP Costs. PSE agrees not to allocate CEIP or TEP costs, proposed to be recovered through a tracker, to customers served under Schedules 448/449.

55. Northwest Pipeline Refund. PSE agrees to amortize the estimated $24.3 million refund from Northwest Pipeline that are attributable to its gas customers over a 12-month period through its 2023 PGA filing. PSE also agrees to amortize the estimated $4.4 million refund from Northwest Pipeline attributable to its electric customers over the 12 months of 2023 as a credit against the forecasted power costs in this case.

56. Streamlining of Reports. The Settling Parties accept PSE's proposed streamlining of reporting as discussed in the testimony of Jon A. Piliaris (Exh. JAP-1T). Further, PSE agrees to update and file its matrix of filings in Docket U-210151 within 30 calendar days of the date of the Commission's final order in this case, and by January 1 each year thereafter.

57. Electric Vehicle Supply Equipment ("EVSE") Payment Methods. PSE shall make minimum payment methods available at all publicly available electric vehicle supply equipment,

owned or supported by the utility, to increase access to all customers. Minimum payment methods should be consistent with California's EVSE Standards, § 2360.2, titled "Payment Method Requirements for Electric Vehicle Supply Equipment." It is the Settling Parties' understanding that this standard does not include the use of "swipe" cards.

N. Performance Based Ratemaking

58. Demand Response ("DR") Performance Incentive Mechanism ("PIM"). The Settling Parties accept PSE's proposed DR PIM as described in the testimony of Dr. Mark Newton Lowry (Exh. MNL-1T), with the following modifications:

a. The initial reward threshold will activate at 105 percent of the DR target. The initial reward from the DR PIM will be a percent of DR program costs equal to PSE's approved weighted average cost of capital ("WACC").

b. The second reward threshold will activate if PSE exceeds 115 percent of the DR target. The reward for this threshold increases to 15 percent of DR program costs.

c. As explained in Exh. MNL-1T at 30:4-5, no additional reward is provided for achievement levels in excess of 150 percent of the target.

d. The PIM is based on the DR target of 40 MW by 2024, to be calculated in the same way that PSE calculates its peak load reduction for compliance with the DR target in PSE's CEIP. This does not replace the requirement to adopt a DR target in the CEIP. The Settling Parties reserve the right to support a higher target in the CEIP docket.

e. The incentive provided by this DR PIM shall not exceed $1 million over the course of this MYRP.

f. Unless otherwise ordered by the Commission, the DR PIM ends at the end of Rate Year 2.

59. Electric Vehicle ("EV") PIM. The Settling Parties agree that there will be no approved EV PIM as part of this rate case.

60. In addition to the metrics discussed by Dr. Mark Newton Lowry (Exh. MNL-1T), PSE agrees to report on the following metrics annually as a compliance filing in this docket and in conjunction with PSE's annual review process, as described in the testimony of Susan E. Free (Exh. SEF-1Tr), and as outlined in the timeline in Exh. JAP-3. Except for the DR PIM, there will be no targets or benchmarks at this time.

61. <u>Resilient, reliable, and customer-focused distribution grid.</u> The Settling Parties agree PSE will report on the following metrics relating to PSE's delivery of a resilient, reliable, and customer-focused distribution grid:

a. Number of EVSE stations and charging ports installed through PSE's TEP programs, broken out by program.

b. Energy served through PSE's TEP programs, per program.

c. Energy and capacity of load reduced or shifted, and percent of load reduced or shifted, through load management activities conducted through PSE's EV tariffs.

d. To the extent readily available, load profiles of energy consumption through PSE's TEP Programs by rate schedule.

e. Percentage of known EV energy sales under managed charging.

f. Percentage of known EVSE in DR programs.

g. Percentage of known EVSE using time-of-use rates.

h. Number of customers served by each of PSE's DER programs.

i. The energy and capacity provided through each of PSE's DER programs.

j. Percentage of utility spending on DR, DER, and renewable energy programs that benefits highly impacted communities or vulnerable populations.

k. Percentage of low-income customers that participate in DR, DER, or renewable energy utility programs

l. Average customer AMI electric bill read success rate.

m. Average customer AMI gas bill read success rate.

n. Average customer remote switch success rate.

o. Average customer reduced energy consumption from voltage regulation.

p. Count of participating customer complaints in each of PSE's TVR pilots.

q. Load reduction during called events for customers enrolled in the Time of Use ("TOU") + Peak Time Rebate ("PTR") pilot.

r. Count of customer impressions with AMI program marketing efforts.

s. High usage alert open rate.

t. Download count of energy data, in both CSV and green button format.

u. Count of customers enrolled in smart thermostat programs for space heating.

62. <u>Environmental Improvements.</u> The Settling Parties agree PSE will report on the following metrics relating to PSE's environmental improvements:

a. Total greenhouse gas ("GHG") emissions from energy delivery systems, reported separately for gas and electric service. The Settling Parties also agree to use this metric in place of "CO2 Emissions from Company-Owned Electric Operations" on PSE's proposed scorecard.

b. Carbon intensity: CO_2e/MWh and CO_2e/MW.

c. Annual SO_2 emissions from utility-owned electric generation resources, by census tract.

d. Annual NOx emissions from utility-owned electric generation resources, by census tract.

e. Annual PM2.5 emissions from utility-owned electric generation resources, by census tract.

63. <u>Customer Affordability.</u> The Settling Parties agree PSE will report on the following metrics relating to customer affordability:

a. Average annual bill for residential customers, separately for electric and gas, by census tract.

b. Average annual bill as a percentage of the average income of all energy-burdened customers, separately for electric and gas.

c. Total revenue recovered from customers outside of rates approved within its MYRP. For this rate case, this would exclude base rates and Schedules 141-C, 141-N and 141-R.

d. Number and percentage of (1) disconnect notices, (2) residential disconnections for nonpayment, and (3) reconnection, each broken out by month and zip code, separately for electric and gas.

e. Total residential arrearages and average age of arrears by month and zip code, separately for electric and gas.

f. Average annual residential bill as a percentage of average residential income, by census tract, separately for electric and gas.

g. Average annual net plant in service per customer, separately for electric and gas.

h. Average annual O&M per customer, separately for electric and gas.

i. Average excess energy burden per household, separately for gas and electric.

64. Advancing Equity in Utility Operations. The Settling Parties agree PSE will report on the following metrics relating to equity in utility operations.

a. To the extent readily available, the number of customers in highly impacted communities and vulnerable populations taking service through PSE's EV tariffs.

b. Percentage of utility transportation electrification spending that is intended to benefit highly impacted communities and vulnerable populations through PSE's programs.

c. Percentage of utility-owned and supported EVSE by use case located within or intended to provide direct benefits and services to highly impacted communities and vulnerable populations.

d. Estimated percentage of PSE suppliers that are minority-owned, women-owned, or veteran-owned.

e. AMI electric bill read success rate for highly impacted communities and vulnerable populations.

f. AMI gas bill read success rate for highly impacted communities and vulnerable populations.

g. Remote switch success rate for highly impacted communities and vulnerable populations.

h. Reduced energy consumption from voltage regulation for highly impacted communities and vulnerable populations.

i. For each DER program: number and percentage of residential customers, known low-income customers, known customers in highly impacted communities and vulnerable populations taking part in each of PSE's DER programs; and average energy savings per home for each of these customer groups. The term "DER programs" is defined to include energy efficiency.

j. Count of customers in highly impacted communities and vulnerable populations taking part in each of PSE's DER programs.

k. The amount of PSE DER program capacity sited in areas of highly impacted communities and vulnerable populations.

l. Total residential arrearages and average age of arrears by month for known low-income households, highly impacted communities, and vulnerable populations.

m. Number and percentage of residential (1) disconnect notices, (2) electric disconnections for nonpayment, and (3) reconnection by month and zip code for known low-income households, highly impacted communities, and vulnerable populations.

n. Percentage of households with a high-energy burden (>6%), separately identifying known low income and highly impacted communities and vulnerable populations, separately for gas and electric by census tract.

O. Comprehensive Decarbonization Study, Targeted Electrification Pilot, and Targeted Electrification Strategy

65. Overview. The Settling Parties agree that PSE will (1) conduct an updated decarbonization study aimed at maximizing carbon reductions with more up-to-date assumptions on targeted electrification, (2) concurrently develop an electrification pilot that will evaluate a range of impacts to gas and electric delivery systems and PSE customers by deploying heat pump technologies, including high-efficiency electric-only solutions, and (3) incorporate a Targeted Electrification Strategy, based on the findings of the updated decarbonization study and electrification pilot, into its next Natural Gas IRP and Biennial Conservation Plan following the conclusion of the study and pilot, as provided below. PSE's final updated decarbonization study and the results of its electrification pilot will be made available to the public with no designations of confidentiality. PSE commits to an investment of up to $15 million in Company funds for these efforts through the end of 2024, which will be deferred for consideration of recovery in PSE's next general rate case. Costs will be allocated as described below. PSE will prioritize low-income customers, highly-impacted and vulnerable populations, and customers experiencing a high energy burden in its pilot programs and incentives developed pursuant to this condition.

66. Decarbonization Study. PSE's updated decarbonization study will build off the gas decarbonization study prepared for PSE by E3 with more up-to-date assumptions regarding efficient Cold Climate Heat Pumps ("CCHPs") for targeted electrification. Measures and scenarios evaluated in the study must include but are not limited to comparisons of cost to ratepayers and GHG emissions associated with installing all electric vs. dual fuel systems for new customers and for existing gas customers, DERs, and decarbonized fuels. This decarbonization study will also include an evaluation of the impacts of all electric heat pumps,

hybrid systems, and reducing and decarbonizing gas throughput. The study will be provided within 12 months of the Commission's final order in this case, and should include but not be limited to the following elements:

a. A more up-to-date electrification scenario that takes into account recent performance trends of CCHPs.

b. An accounting of both near-term (3-5 years) and long-term costs and benefits of electrification, including carbon reductions and avoided gas system infrastructure costs due to fewer new customer connections.

c. A segmentation of new and existing customers to separately evaluate the costs and benefits of electrifying new and existing customers and a scenario whereby PSE seeks to electrify all new customers and projected corresponding carbon emission reductions.

d. A review of the time to build out and the cost of incremental electric system costs based on recent cost trends in power and capacity, as well as sensitivity analysis around electric system assumptions to understand how these assumptions impact the viability of high electrification scenarios.

e. Updated unit costs, including the incentives provided by the Inflation Reduction Act.

f. Study the impacts and benefits of electric heat pump technologies on PSE's gas constrained delivery systems.

g. Collaborate with adjacent consumer-owned utility electric service providers to conduct coordinated electric delivery system and gas delivery system studies or pilots.

h. Evaluate how to use the biennial conservation planning process to advance least-cost decarbonization strategies in PSE's gas utility service area, including by promoting fuel switching to electric utility service.

i. Include regional forecasted load and market price sensitivities that reflect regional electrification.

j. An evaluation of the impact of electrification with and without hybrid heat pumps on gas and electric rates, to provide an update to the existing analysis in the E3 study referenced above.

k. The results of the updated study will be incorporated into PSE's 2025 Natural Gas Integrated Resource Plan and a compliance filing in this docket by January 2025.

67. Targeted Electrification Pilot. PSE will conduct an 18-month Targeted Electrification Pilot.[15] The pilot will deploy strategies to maximize effective carbon reduction measures associated with the deployment of electric-only heat pumps in homes and buildings with wood, oil, propane, electric resistance and gas heating. This pilot is targeted toward residential and small commercial customers.

a. The pilot will have a target of engaging 10,000 customers through at least two of the following measures:

    i. rebates and incentives for fuel switching to high-efficiency electric-only appliances that includes consideration of carbon emission reduction potential,

[15] The measures supported through the Targeted Electrification Pilot will be in addition to and separate from PSE's existing hybrid heat pump pilot program.

ii. remote and in-home electrification assessments, and

iii. education related to available electrification incentives and programs as described in item (d)(iv) below.

b. PSE agrees to file a report summarizing the results of the Targeted Electrification Pilot, including the number of residential and commercial customers engaged through each of the measures identified above, as a compliance requirement in this docket, no later than January 2025.

c. Funding for the Targeted Electrification Pilot program will only be used to support promotion or installation of high-efficiency electric-only appliances. However, to assist existing gas customers in transitioning to electric solutions, the pilot may rely upon existing gas appliances for back-up fuel supply (e.g., installing new electric-only heat pumps while maintaining existing gas furnaces as backup fuel supply).

d. The Targeted Electrification Pilot will also integrate the following elements to advance electrification efforts:

i. Identify opportunities for incremental DER investment as a mechanism to offset electric system reliability risk during peak load events and begin deploying these investments.

ii. Identify barriers to heat pump adoption and develop recommendations for improving the penetration of heat pump technologies in PSE's service territory.

iii. Identify barriers to low-income customers, highly-impacted populations, vulnerable populations, and customers experiencing high energy burdens accessing heat pump technology, and develop policies and programs to support adoption of heat pump technologies by those customers and populations.

iv. Provide education and outreach to customers on qualified installers, and available utility incentives offered through the pilot, or from state and federal sources (e.g., Inflation Reduction Act).

v. Evaluate whether providing a financial incentive to existing gas customers for fuel switching to electric-only appliances, would incentivize and promote increased adoption of high-efficiency electric-only appliances.

e. In consultation with the CRAG, findings from the Targeted Electrification Pilot should be considered in the 2025 Biennial Conservation Plan (for the 2026-2027 biennium).

f. PSE will consult with the LIAC and the CRAG to ensure the Targeted Electrification Pilot program and Targeted Electrification Strategy provide demonstrated material benefits to low-income participants, enrolls eligible participants in bill assistance programs, and includes appropriate low-income customer protections. As part of this consultation, PSE will consider the following:

i. Any guidance from the Department of Commerce concerning low-income electrification programs.

ii. What defines a material benefit to low-income customers; e.g., decreased energy burden, and/or back up heat sources or energy storage systems in areas with frequent outages if necessary to protect health and safety.

iii. Notification if participation will increase energy burden.

g. Costs will be spread to each electric rate schedule based on the schedule's share of total Targeted Electrification Pilot program funding expended for that schedule. For clarity, costs will not be allocated to Schedule 449 customers.

68. Targeted Electrification Strategy. PSE will use the information and analysis from the Targeted Electrification Pilot together with the updated decarbonization study to develop a Targeted Electrification Strategy for its electric service territory in its next Natural Gas Integrated Resource Plan or Progress Report following the completion of the Decarbonization Study and Targeted Electrification Pilot, and as a compliance filing in this docket by January 2025, and its 2025 Gas IRP. The Targeted Electrification Strategy will be based on findings from the Decarbonization Study, and the Targeted Electrification Pilot.

a. The Targeted Electrification Strategy will focus on maximizing carbon emission reductions consistent with legal requirements at the lowest reasonable cost, which includes consideration of adverse rate impacts to remaining gas customers and avoidance of inter-rate class cost shifting.

b. The Targeted Electrification Strategy shall consider a comprehensive set of strategies to minimize inter-class cost shifting, including the potential use of regulatory assets to shift rate base if the proposed strategy would create stranded assets.

c. The Targeted Electrification Strategy shall consider a comprehensive set of strategies, programs, incentives, promotional materials, and other measures to encourage electrification for new and existing customers.

d. The Targeted Electrification Strategy shall provide for a fuel-switching rebate that incentivizes gas customers to install electric-only appliances, to the extent that fuel switching to high-efficiency electric appliances is determined to be a cost-effective method to decarbonize gas utility service. This fuel switching rebate will provide an additional financial incentive to existing energy efficiency appliance rebates to promote rapid fuel switching to high-efficiency electric only appliances.

e. In consultation with the CRAG, PSE will integrate fuel switching concepts from gas to electric into its conservation planning for the next Biennial Conservation plan following the completion of the Targeted Electrification Strategy. In developing these concepts, PSE's approach will be informed by the steps outlined in the Equitable Building Electrification Framework. [16]

f. The Targeted Electrification Strategy shall include a proposed budget, and plan for implementing the measures and strategies that were studied in the electrification pilot and described in item b. above, a proposal to limit or phase out incentives for new gas appliances, based on an evaluation of their continued cost-effectiveness and risk to ratepayers. This strategy will also set

[16] https://greenlining.org/publications/reports/2019/equitable-building-electrification-a-framework-for-powering-resilient-communities/

annual targets to continue reducing new gas customer additions in future years.

g. PSE agrees to work with the CRAG on developing educational and communications materials encouraging customers to fuel switch to electric-only appliances in line with PSE's conservations targets, if the Targeted Electrification Strategy provides a fuel-switching rebate to customers, per sub-item (d).

h. The funds for the Targeted Electrification Strategy will be recovered from the class benefiting from the program.

i. PSE agrees to phase out promotional advertising specific to connecting new customers to the gas system or encouraging customers to switch to gas utility service away from other forms of energy service, as described in WAC 480-90-223 (including mailers to customers, promotions on PSE's website and social media, print, digital, television, and radio advertisements, etc.) by January 1, 2023.

IV. GENERAL PROVISIONS

69. <u>Entire Agreement.</u> This Settlement is the product of negotiations and compromise amongst the Settling Parties and constitutes the entire agreement of the Settling Parties. Accordingly, the Settling Parties recommend that the Commission adopt and approve the Settlement in its entirety as a full resolution of contested issues identified in this Settlement. This Settlement will not be construed against any Settling Party on the basis that it was the drafter of any or all portions of this Settlement. This Settlement supersedes any and all prior oral and written understandings and agreements on such matters that previously existed or occurred in

this proceeding, and no such prior understanding or agreement or related representations will be relied upon by the Settling Parties to interpret this Settlement or for any other reason.

70. Confidentiality of Negotiations. The Settling Parties agree that this Settlement represents a compromise in the Settling Parties' positions. As such, conduct, statements, and documents disclosed during the negotiation of this Settlement are not admissible in this or any other proceeding and will remain confidential. Notwithstanding the foregoing, the Settlement itself and its terms do not fall within the scope of this confidentiality provision, and each Settling Party is free to publicly disclose the basis for its own support of the Settlement.

71. Precedential Effect of Settlement. The Settling Parties enter into this Settlement to avoid further expense, uncertainty, inconvenience, and delay. This Settlement does not serve to bind the Commission when it considers any other matter not specifically resolved by this Settlement in future proceedings. Nothing in this Settlement compels any Settling Party to affirmatively intervene or participate in a future proceeding.

72. Positions Not Conceded. In reaching this Settlement, the Settling Parties agree that no Settling Party concedes any particular argument advanced by that Settling Party or accedes to any particular argument made by any other Settling Party. Nothing in this Settlement (or any testimony, presentation, or briefing supporting this Settlement) shall be asserted or deemed to mean that a Settling Party agreed with or adopted another Settling Party's legal or factual assertions in this proceeding.

73. Manner of Execution. This Settlement will be deemed fully executed when all Settling Parties have signed it. A designated and authorized representative may sign the Settlement on a Settling Party's behalf. The Settling Parties may execute this Settlement in counterparts. If the Settlement is executed in counterparts, all counterparts shall constitute one

agreement. A Settlement signed in counterpart and sent by facsimile or emailed as a pdf is as effective as an original document. A faxed or emailed signature page containing the signature of a Settling Party is acceptable as an original signature page signed by that Settling Party. Each Settling Party shall indicate the date of its signature on the signature page. The date of execution of the Settlement will be the latest date indicated on the signature page(s).

74. Approval Process and Support of Settlement. Each Settling Party agrees to support the terms and conditions of this Settlement in this proceeding. Each Settling Party agrees to support the Settlement during the course of whatever proceedings and procedures the Commission determines are appropriate for approval of the Settlement. Each Settling Party agrees to make available one or more witnesses to testify in support of the Settlement.

75. Commission Approval with Conditions. In the event the Commission approves this Settlement, but with conditions not proposed in this Settlement, the provisions of WAC 480-07-750(2)(b) will apply.

76. Commission Rejection. In the event the Commission rejects this Settlement, the provisions of WAC 480-07-750(2)(c) will apply. In that event, the Settling Parties agree to jointly and promptly request that the Commission convene a prehearing conference to address procedural matters, including a procedural schedule for resolution of the case at the earliest possible date.

Dated this 26th day of August, 2022.

PUGET SOUND ENERGY

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Director, Regulatory Affairs

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ALLIANCE OF WESTERN ENERGY CONSUMERS

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Dated this 26th day of August, 2022.

PUGET SOUND ENERGY

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EXH. MNL-1T
DOCKETS UE-22___/UG-22___
2022 PSE GENERAL RATE CASE
WITNESS: MARK NEWTON LOWRY

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**Docket UE-22____** **Docket UG-22____**

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF

MARK NEWTON LOWRY

ON BEHALF OF PUGET SOUND ENERGY

JANUARY 31, 2022

PUGET SOUND ENERGY

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF MARK NEWTON LOWRY

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PUGET SOUND ENERGY

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF MARK NEWTON LOWRY

I. INTRODUCTION

Q. Please state your name, current occupation, and business address.

A. My name is Mark Newton Lowry. I am the President of Pacific Economics Group Research LLC ("PEG"). My business address is 44 East Mifflin Street, Suite 601, Madison, Wisconsin, 53703.

Q. Have you prepared an exhibit describing your education, relevant employment experience, and other professional qualifications?

A. Yes. This information is provided in Exh. MNL-2.

Q. Please summarize your professional experience.

A. I earned a PhD in applied economics from the University of Wisconsin and have worked as an economist for more than thirty years. Most of my work has been in the field of utility economics. My specialties include performance-based regulation ("PBR") and statistical research on energy utility performance. I have testified on these topics in more than 50 rate proceedings. I have additionally spoken at many conferences on these topics and have authored dozens of professional publications. Before becoming President of PEG in 2009, I was a partner in an antecedent company based in Pasadena, California for over 10 years.

Prior to that I was a vice president at Laurits R. Christensen Associates here in Madison and spent several years as an assistant professor teaching energy economics at the Pennsylvania State University.

Q. What are your duties at PEG?

A. PEG is a consulting firm that works primarily in the field of energy utility economics. We are well known for our PBR and statistical performance research. Our personnel collectively have over seventy years of experience in these fields, which have a common foundation in economic statistics. Working for diverse clients that include utilities, regulators, government agencies, and consumer and environmental groups has given us a reputation for objectivity and dedication to good regulation. PBR for vertically-integrated electric utilities and gas utilities are specialties.

My principal duties as President of PEG are the supervision of research, client consultation, and the provision of expert witness testimony. I also oversee the company's business affairs.

II. PURPOSE OF TESTIMONY

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of Puget Sound Energy ("PSE" or "the Company").

Q. What is the purpose of your testimony?

A. In this proceeding, PSE is filing a rate case and a PBR proposal that includes a multiyear rate plan ("MYRP"). My testimony provides an overview of PBR and MYRPs, describes and appraises the Company's MYRP proposal, and discusses in some detail the performance metrics in the proposal. Senate Bill 5295 provides for a transformation of Washington energy utility regulation in the direction of MYRPs and other kinds of PBR such as performance metrics and performance incentive mechanisms ("PIMs"). The Company retained PEG to help it develop metrics and PIMs for its MYRP proposal. PSE also asked us to prepare a report and testimony that provides a constructive overview of PBR and discusses the metrics and other PIMS in the Company's proposed plan. The report is contained in Exh. MNL-3.

Q. Please provide an overview of the report on Performance-Based Regulation you prepared for PSE.

A. The report discusses some limitations of traditional ratemaking under modern business conditions and how these limitations have led to the development of PBR. Succeeding sections of the report discuss the major PBR approaches.

The final section of the report considers PBR for Puget Sound Energy. It begins by discussing key features of PSE's operations and regulatory environment. The report notes that the Company is currently operating under several forms of PBR and that rate regulation using MYRPs and PBR has been legislatively mandated in

Washington. The report concludes with a discussion of the Company's MYRP, according particular attention to the metrics and PIMs contained therein.

III. PERFORMANCE-BASED REGULATION

Q. Please provide an overview of PBR.

A. Dissatisfaction with the traditional cost of service approach to ratemaking ("COSR") has prompted the development of diverse alternative approaches that are collectively called "alternative regulation" or "Altreg." These Altreg approaches vary in the incentives they provide to utilities to perform well. Altreg approaches that provide relatively strong performance incentives are called performance-based regulation.

There are four well-established approaches to PBR.

- Decoupling. The relationship between revenue and system use can be relaxed through such means as revenue decoupling. Decoupling reduces the "throughput" incentive that discourages utilities from embracing demand-side management ("DSM"). It also encourages innovative rate designs that facilitate DSM.

- Performance Metrics. Metrics can be used to monitor utility activities in key performance areas. They can be paired with targets to measure utility performance. Metrics and targets can provide the basis for PIMs that link the earnings of a utility to its measured performance. Metrics that are not paired with targets or PIMs may be called "tracker" metrics.

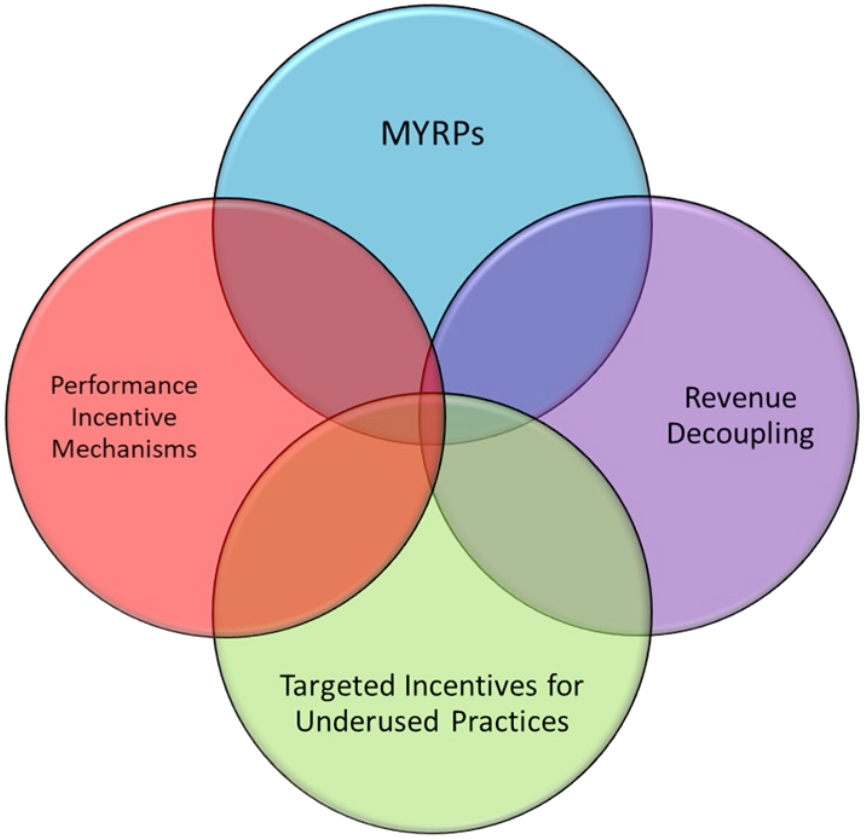
- Targeted Incentives for Underused Practices. Other PBR provisions provide targeted encouragement for desirable practices that utilities tend to underuse. These provisions include pilot programs, management fees, trackers and associated rate riders or deferrals for costs of underused practices, the capitalization of certain costs that are operation and maintenance ("O&M") expenses, and rate of return premiums. A common example is the tracker treatment of DSM expenses.

- Multiyear Rate Plans. MYRPs strengthen the incentive of utilities to contain the cost of their base rate inputs. This is due in part to a reduction in the frequency of rate cases. Reduced rate case frequency also streamlines regulation, freeing resources in the ratemaking community to concentrate on other matters such as integrated resource and clean energy plans, new rates and services, and important emerging generic issues. The efficiency of regulation is thus enhanced.

These PBR approaches are often used in combination as depicted in Figure 1 below. For example, multiyear rate plans often feature revenue decoupling, several performance metrics and PIMs, and some pilot programs and trackers for costs of underused practices.

Figure 1

PBR Approaches are Often Combined



Q. How are multiyear rate plans typically constructed?

A. MYRPs have the following common characteristics.

- A moratorium is placed on general rate cases. Rate cases are typically held every three to five years, but plan terms of eight and ten years have been approved.
- There is usually a need for the revenue of a utility to grow between rate cases since its costs tend to grow for reasons that include demand growth, input price inflation, and a need to modernize facilities. In an MYRP a revenue adjustment mechanism ("RAM") compensates the utility for some cost pressures between rate cases without closely tracking the utility's actual cost growth.
- Costs that are difficult to address with the RAM may instead be accorded tracker treatment. Energy commodity costs are most commonly tracked.

- Revenue adjustments are typically permitted for events that affect utility finances, are largely beyond the utility's control, and difficult to foresee. These events are sometimes said to be "Z factored." Events that are commonly eligible for Z factoring include major storms, changes in accounting standards, transportation system construction, and changes in tax laws or regulatory policies.

- MYRPs often also include service quality metrics and PIMs.

A number of other provisions are sometimes added to MYRPs, including the following.

- Revenue decoupling is a component of many MYRPs.

- Many plans have additional performance metrics and PIMs.

- Some MYRPs feature an earnings sharing mechanism ("ESM") that shares surplus and/or deficit earnings with customers when the utility's rate of return on equity ("ROE") varies from the commission-authorized target.

- Off-ramp mechanisms may permit reconsideration and possible suspension of an MYRP under pre-specified outcomes such as an unusually high or low ROE.

- Special incentives for underused practices are also found in many MYRPs. For example, costs of DSM are usually tracked and pilot programs are common.

- Some MYRPs have marketing flexibility provisions. These typically involve light-handed regulation of optional rates and services that a utility offers. The optional services that PSE already offers include green power and managed residential EV charging. Provisions like these can help utilities respond to the complex and changing needs of customers and encourage beneficial loads.

Q. How popular is the MYRP approach to regulation?

A. MYRPs have been used in North America since the 1980s. They were first used on a large scale for railroads and incumbent telecommunications carriers. These industries had a particular need for marketing flexibility and achieved rapid productivity growth under MYRPs. The Federal Energy Regulation Commission has used MYRPs for many years to regulate oil pipelines.

MYRPs have also been used on many occasions to regulate retail services of gas and electric utilities. Recent precedents for MYRPs in North America are detailed in the maps below in Figure 2 and Figure 3. In the United States, California utilities have operated under commission-imposed rate plans that limit the frequency of rate cases since the 1980s. MYRPs became popular in some northeastern states (e.g., Maine, Massachusetts, and New York) in the 1990s.

MYRPs are now fairly widespread. Today, energy distributors operate under MYRPs in California, Ohio, New York, and New England. Use of MYRPs has also spread to vertically-integrated electric utilities ("VIEUs") in diverse states including Arizona, Florida, Louisiana, Minnesota, and Virginia. In addition to Washington, a recent law encourages MYRPs in North Carolina.

MYRPs are even more widely used in Canada to regulate energy utilities. British Columbia, Washington's neighbor province, was an early innovator and recently decided to regulate BC Hydro, a large VIEU, with a MYRP. MYRPs are also common in Alberta, Ontario, and Québec. Overseas, MYRPs are the norm for energy utilities in several English-speaking countries (e.g., Australia) as well as in western Europe.

Figure 2

Recent MYRPs for Energy Utilities in American States

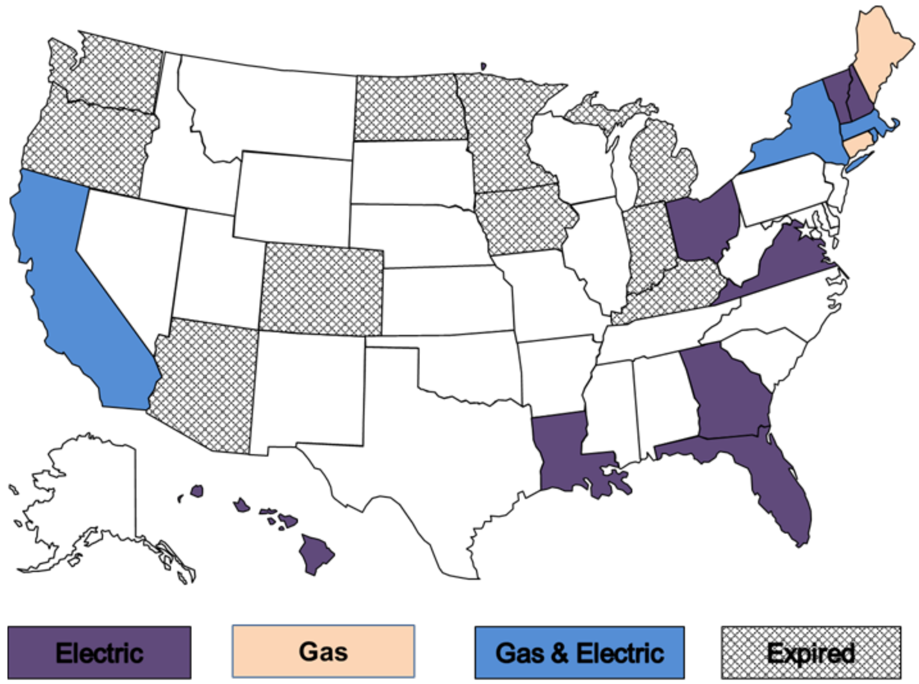
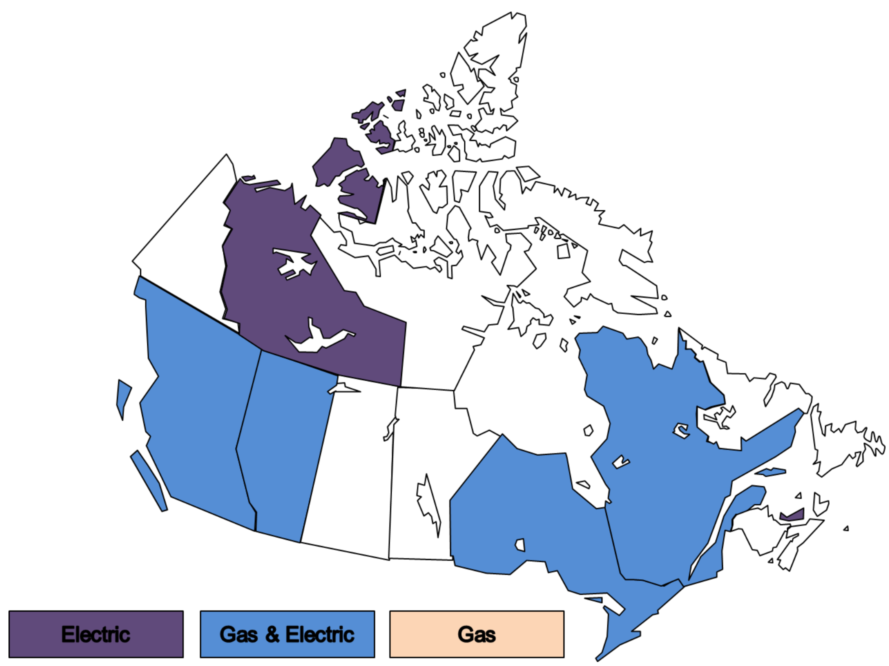


Figure 3

Recent MYRPs for Energy Utilities in Canadian Provinces



Q. Please discuss the design of revenue adjustment mechanisms.

A. There are several well-established approaches to RAM design.

- Cost growth can be forecasted over a multiyear period. In MYRPs in Minnesota, New York, and Ontario, forecasts of capital cost growth have been combined with refunds when actual capital cost was less than was forecasted.
- Revenue growth can be indexed to customer growth and inflation. This approach is especially popular for energy distribution.
- Rates (or revenue per customer) can be frozen, with supplemental revenue permitted for the annual cost of plant additions.
- Hybrid revenue caps feature a mix of these basic approaches. California is a well-known practitioner.

Q. How are performance metrics used in utility regulation?

A. Performance metrics quantify aspects of utility operations which matter to customers and the public. A performance metric system can routinely monitor select metrics and use them in performance appraisals. These systems usually include a mix of PIMs, metrics with targets, and tracker metrics. Scorecards summarizing results for key metrics are often tabulated and posted on a publicly-available website.

Q. What are the advantages of metrics and PIMs?

A. Metrics and PIMs have innate advantages in ratemaking.

- PIMs can strengthen financial incentives to perform better in targeted areas that matter to regulators, customers, and the general public. Even in the absence of explicit financial incentives, utilities have some incentive to perform well in areas where there are metrics because they can garner valuable goodwill from regulators and the public.

- Metrics and PIMs have been found particularly useful in addressing weak spots in regulatory system incentives. For example, many observers believe that a salient weak spot in most energy utility ratemaking systems is a lack of incentives to contain environmental damage. For instance, although there is significant concern about greenhouse gas ("GHG") emissions, absent some form of carbon tax or GHG regulation, there has been little incentive to address them. Other parties will be concerned about the terms of service to low-income and other disadvantaged groups in the service territory. PIMs can help align utility regulation with public policy goals.

Incentive weak spots can exist even in systems that contain other PBR mechanisms. One reason is that other PBR provisions can sometimes create undesirable incentive "side effects" that metrics and PIMs can address. For example, the stronger incentives that MYRPs can engender to contain the cost of base rate inputs may raise concerns about the quality of utility services. Service quality PIMs are a useful complement.

- Metrics and PIMs are also useful for alerting utilities to key concerns of regulators and stakeholders, such as chronically poor performance in a certain area.

- The array of metrics can evolve as new performance concerns arise and some older concerns recede.

- PIMs can reduce the need for traditional prudence oversight. For example, reliability PIMs can reduce (but probably not eliminate) the need to spend time on formal reviews of reliability.

- Other means of strengthening incentives and/or reducing regulatory cost are sometimes less feasible. For example, incentivizing energy cost containment with only a partial passthrough tracker can be risky because these costs are volatile. A PIM for energy efficiency programs is an alternative.

Q. What are some of the challenges encountered in PIM design?

A. Performance is often difficult to measure accurately, for several reasons.

- The outputs from some utility activities are hard to quantify. An example is the load savings from utility efforts to encourage development of markets for DSM products and services.
- Some metrics (e.g., reliability, delivery volumes, and peak loads) are sensitive to external business conditions, and these conditions are sometimes volatile. The utility is not then fully responsible for their metric values. The impact of external business conditions on performance metrics may be unclear and/or complicated.
- Standardized data on metrics and business conditions that affect them are often unavailable for numerous utilities. These problems can make it difficult to base performance targets for many metrics on operating data from other utilities.

It can also be difficult to correctly *value* performance and establish appropriate award/penalty rates for PIMs. For example, the value of improved service quality or reductions in carbon emissions can be difficult to quantify. Even where the value of improved performance is clear, the share of benefits that utilities should receive may not be. Customer interests are disserved if awards exceed those needed to incentivize good behavior. The appropriate PIM may have a nonlinear form, so that award and penalty rates should rise or fall with measured performance.

The design and operation of PIMs can invite controversy and strategic behavior by parties to regulation. For example, controversy has sometimes arisen over the load impact of DSM programs that are addressed by PIMs. Utilities typically resist PIMs with penalty provisions while other parties resist PIMs with reward provisions.

The incremental regulatory cost of adding several metrics and PIMs to a regulatory system can be non-negligible. A performance metric system can in principle grow so large and complex as to constitute an undue administrative burden.

Q. Do these considerations have consequences for real-world PIMs?

A. Yes. PIMs tend to be limited to situations where parties are really concerned about performance. Awards are often modest and sometimes capped. Some metrics in a performance metric system will have targets but no PIMs. Tracker metrics are common.

The need for PIMs tends to be greater to the extent that the regulatory system otherwise has weak incentives. For example, the need for energy efficiency PIMs is greater in the absence of revenue decoupling. PIMs also tend to be used where they are easy to develop and administer.

Complex calculations are often eschewed in PIM design. For example, the award and penalty rates of service quality PIMs rarely reflect sophisticated calculations of the costs or benefits of changes in quality. The California Public Utilities Commission abandoned the complicated shared savings approach to the calculation of awards for DSM programs. Utilities instead receive a share of DSM expenses as a management fee.

Some PIMs have dead bands or permit adjustments for the impact of external business conditions. For example, reliability metrics used in PIMs usually exclude major event days ("MEDs") because these days are typically the result of unusually severe weather or other extraordinary events.

Q. What are some popular uses of PIMs?

A. Service quality is probably the most common area of utility operations addressed by metrics and PIMs. Service quality metrics for energy utilities have traditionally fallen into three general categories: reliability, customer service, and safety. Service quality PIMs can strengthen incentives to maintain or improve quality and simulate the connection between revenue and product quality that firms in unregulated markets experience.

Demand side management PIMs have also been popular. These typically reward the utility for success in its energy efficiency ("EE") programs. The focus is on the load savings attributable to EE and a PIM can strengthen utility incentives to embrace EE. Although decoupling can remove the throughput incentive that discourages EE, a well-designed PIM can provide an additional *positive* incentive that is needed because EE reduces capex opportunities or because costs that might be saved due to EE are external to the company's finances.

Q. Has interest in PIMs been growing?

A. Yes. Growing interest in PIMs has been spurred in part by Great Britain's "RIIO" approach to MYRP design. The term RIIO stands for "Revenue = Incentives + Innovation + Outputs." The RIIO system features MYRPs with elaborate and innovative arrays of metrics, PIMs, and targeted incentives for underused practices.

Performance metric systems are evolving to meet new industry challenges. For example, severe storms and wildfires in some states has spurred interest in resiliency metrics and PIMs. PIMs that address special concerns of policymakers are sometimes called policy PIMs. Policy PIMs often asymmetrically feature only rewards for good performance.

Q. Does this Commission already have some experience with PBR?

A. Yes, the Washington Utilities and Transportation Commission ("UTC" or "the Commission") has experience with all four kinds of PBR and much of this experience is in its regulation of PSE. The Company has previously operated under MYRPs for its electric and gas services on two occasions. It has for many years had an extensive set of service quality metrics and PIMs. PSE has twice operated for several years under revenue decoupling. The Company had an energy efficiency PIM prior to the resumption of decoupling. The Commission's experience with PBR increases the chances that they will oversee its expanded use in Washington effectively.

As for targeted incentives for underused practices, the Company's DSM expenses have long been tracked, and PSE has had several pilot programs. In addition, House Bill 1853 of 2015 authorizes an incentive rate of return of up to 2% on utility investments in electric vehicle supply equipment. The Clean Energy Transformation Act ("CETA") permits utilities to defer and earn a return on the costs of power purchase agreements in their clean energy action plans.

IV. THE COMPANY'S MYRP PROPOSAL

Q. What laws are pertinent to the design of an MYRP in the state of Washington?

A. SB 5295 requires gas and electric utilities to propose MYRPs in their rate cases. It also established MYRP guidelines, including the following.

- For each year of an MYRP, the Commission shall ascertain and determine "the fair value for rate-making purposes of the property of any gas and electrical company that is or will be used and useful under RCW 80.04.250 for service" along with "the revenues and operating expenses for ratemaking purposes."[1]
- The Commission is accorded substantial flexibility in the approval of plan details. Subsection 2(3)(d) of the law states, for example, that

  > [i]n ascertaining and determining the fair value of property of a gas or electrical company pursuant to (b) of this subsection and projecting the revenues and operating expenses of a gas or electrical company pursuant to (c) of this subsection, the commission may use any standard, formula, method, or theory of valuation reasonably calculated to arrive at fair, just, reasonable, and sufficient rates.

- Plans must have a particular kind of ESM. All earnings more than 50 basis points above allowed levels shall be deferred "for refunds to customers or

[1] SB 5295 Sec. 2.3(b) and (c).

another determination by the commission in a subsequent adjudicative proceeding."[2]

- The Commission must determine a set of performance measures that will be used to assess a gas or electrical company operating under an MYRP.
- The term of the plan may be as long as four years. A utility is bound by the terms of the plan in years one and two but may file for new terms to be effective beginning in year three or in any fourth year of a rate plan.
- Plans must also have provisions for low-income customers which include a discount rate for these customers as well as grants and other low-income assistance programs.

In addition, SB 5295 requires the UTC to conduct a proceeding to develop a policy statement on alternatives to COSR which includes "performance measures or goals, targets, performance incentives, and penalty mechanisms." The Commission has proposed a schedule for this proceeding under which metrics would be addressed first, and a policy statement on metrics is to be issued in March 2023. A policy statement on PIMs is to be issued in December 2024.

Q. Have any policies established by the Commission been considered in the development of the Company's MYRP proposal?

A. Yes. In Docket U-190531 the UTC established a policy concerning the ratemaking treatment of utility assets that are expected to become used and useful after the rate effective date of an MYRP. The Commission permits provisional recovery in rates of the cost of such rate-effective period property. However, this revenue may be reviewed and refunded to customers if the Commission later

[2] SB 5295 Sec. 2 (6).

determines that the assets are not used and useful or that the cost of the assets is not known and measurable, adequately matched to offsetting factors, or prudently incurred. If identified investment costs exceed the amount the regulated company is collecting from customers based on its proposed, estimated, or projected costs, the Company may file an accounting petition.

Q. Please provide an overview of the Company's MYRP proposal.

A. The Company's proposed MYRP is detailed in the Prefiled Direct Testimony of Jon A. Piliaris, Exh. JAP-1T. Some salient features of PSE's proposed MYRP include:

- Initial rates would be established in this proceeding.
- Escalation of base revenue would be driven for two years by the Company's latest five-year financial plan. This five-year financial plan is detailed in the Prefiled Direct Testimony of Joshua A. Kensok, Exh. JAK-1T. Of the various approaches to RAM design that I discussed above, this one is most consistent with RCW 80.28.425(3) parts (b) and (c).
- The portion of the Company's proposed rate increases that is tied to projections of the costs of assets that are expected to become used and useful during the plan is subject to refund pending a Commission review. This provision is consistent with the Commission's decision in Docket U-190531 and other jurisdictions whose MYRPs have been approved.
- Revenue would be subject to an adjustment for unforeseen inflation.
- Revenue decoupling would continue for gas and electric services to residential and most commercial and industrial customers; this is vitally important to encourage DSM and supportive rate designs.
- Any surplus earnings, defined as those which would cause the Company's rate of return on rate base ("ROR") to exceed its authorized target by more than 50 basis points, would be deferred for refunds to customers or another determination by the Commission in a subsequent proceeding.

- There are various provisions to assist highly impacted communities ("HIC) and vulnerable populations ("VP"), including a special rate for low-income customers.
- There is a shortlist of performance metrics and PIMs that are particularly appropriate for tracking PSE's performance and encouraging good performance. Results would be posted on a publicly-available MYRP scorecard. Additional metrics on various topics will continue to be reported routinely by PSE in other venues.
- Unless the Company exercises the right to request a new plan prior to year three, the plan will have a term of three years.

V. PERFORMANCE METRICS AND PIMS IN THE PSE PROPOSAL

A. Development of PSE's Performance Metrics and PIMs

Q. How were the performance metrics and PIMs in the PSE MYRP developed?

A. In developing the performance metrics and PIMs in the Company's proposed MYRP, PSE was guided by applicable legislation, including the CETA. PSE also considered the criteria itemized in SB 5295 for evaluating metrics and other PBR plan provisions. Those criteria emphasize environment and equity considerations as well as the more traditional regulatory concerns about cost and reliability.

PSE also considered that the Commission is undertaking a generic proceeding to develop policies concerning metrics and PIMs. The Company intends that its proposal and supportive evidence on the MYRP, metrics, and PIMs will help to inform the Commission on these issues. This evidence is not, however, intended to supplant the UTC's effort to fashion PBR policies. Cautious steps in the development of PIMs seem warranted until the Commission's generic proceeding advances. The Commission's generic proceeding may lay the foundation for new metrics and PIMs in the Company's subsequent MYRPs.

The development of the proposed metrics and PIMs was also influenced by PEG's appraisal of weak spots in the incentives included in typical utility regulatory systems. Another consideration was the input obtained from collaboration with UTC staff and stakeholders.

Q. Please discuss the metrics collaborative.

A. PSE established a collaborative process to exchange ideas with stakeholders about metrics and PIMs for its MYRP. Participants in this process included the Alliance of Western Energy Consumers, Climate Solutions, the Energy Project, the NW Energy Coalition ("NWEC"), Public Counsel, and UTC staff. Four meetings were held between August 20 and November 15 of 2021. PSE presented detailed draft metrics and PIMs in a meeting on October 8. NWEC presented a proposal that included PIMs in several areas, such as demand response, equity, and transportation electrification, in the meeting on November 15.

Notable takeaways from discussions with stakeholders included the following.

- Some stakeholders wanted to discuss PIMs and metric-target pairings, not just lists of metrics.
- Metrics and PIMs should target identified problems that require attention.
- Consumer groups questioned the need for PIMs with rewards.
- Several stakeholders espoused the view that PSE should not be rewarded for things that the Company is already incented or required to do.

> Incentives should encourage “new or improved programs and services that utilities would not otherwise pursue.” There should be a “rigorous baseline setting” and a “high bar of additionality.”

Q. Please summarize the performance metrics and PIMs in the Company’s proposed MYRP.

A. The proposed metrics and PIMs are summarized in Table 1 below. A scorecard containing the proposed metrics is detailed in Table 2. This scorecard contains historical values for the metrics where they are available, and it also includes any targets or baselines that are proposed. Details of the metrics and targets are provided in Exh. MNL-4. In addition to service quality, metrics are proposed in the areas of affordability, demand response, energy efficiency, electric vehicles, greenhouse gas emissions, and advanced metering infrastructure (“AMI”). In keeping with the equity goals of CETA, analogous metrics are reported in these areas for highly impacted communities (“HIC”) and vulnerable populations (“VP”) where practical. Policy PIMs are proposed in two areas where NWEC made proposals, although the specifics of the PSE and NWEC proposals differ.

Table 1

Overview of Proposed Metrics and PIMs

	Systemwide	Highly-Impacted Communities and Vulnerable Populations
Customer Cost and Affordability	**Affordability**	
		Number of low income customers receiving bill assistance Share of bill assistance customers who are in highly impacted and vulnerable communities
Customer Cost and Affordability; Environmental Impact	**Demand-Side Management**	
	Peak Load Management Savings (PIM) Peak load management savings attributable to residential customers Annual energy efficiency savings (electric and gas)	Number of customers participating in gas and electric energy efficiency programs from highly impacted communities and vulnerable populations
Customer Cost and Affordability; Environmental Impact	**Electric Vehicles**	
	Number of Residential and Fleet EV Chargers Used in Managed Charging Programs or TOU Rates (PIM) Number of light-duty electric vehicles	Number of public charging ports serving highly impacted communities and vulnerable populations
Environmental Impact	**Greenhouse Gas Emissions**	
	CO_2 emissions from company-owned electric operations	
Environmental Impact	**Advanced Metering Infrastructure**	
	Reduced energy consumption from voltage reduction Remote switch success rate AMI bill read success (gas and electric)	
Service Quality & Safety	**Safety SQIs (several metrics, some PIMs)**	
Service Quality & Safety	**Customer Satisfaction SQIs (several metrics, some PIMs)**	
Service Quality & Safety	**Customer Service SQIs (several metrics, some PIMs)**	
Service Quality & Safety	**Field Operations SQIs (several metrics, some PIMs)**	
Service Quality & Safety	**Electric Service Reliability SQIs (several metrics, some PIMs)**	
	Revised SAIDI and SAIFI metrics for non-storm days	SAIDI and SAIFI metrics in highly impacted communities and vulnerable populations

Note: Items in bold text include PIMs

Table 2

Proposed PSE Scorecard

Current SQI Metrics

Category	Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target
Customer Satisfaction	Complaints per 1,000 Customers to the WUTC	0.18	0.2	0.16	0.16	0.1		Less than 0.4
	Customer Access Center Transactions Customer Satisfaction	93%	93%	94%	92%	94%		At least 90%
	Field Service Operations Transactions Customer Satisfaction	95%	94%	95%	95%	96%		At least 90%
Customer Service	Calls Answered by a Live Representative Within 60 Seconds of Request*	82%	82%	81%	81%	84%		At least 80%
	Percent of Appointments Kept	100%	100%	100%	100%	99%		At least 92%
Gas Safety	Average Gas Safety Response Time	31 minutes	32 minutes	30 minutes	32 minutes	32 minutes		No more than 55 minutes
Electric Safety	Average Electric Safety Response Time	55 minutes	55 minutes	52 minutes	54 minutes	51 minutes		No more than 55 minutes
Electric Reliability	SAIFI All Outages Current Year ($SAIFI_{TOTAL}$)	1.70 interruptions	1.80 interruptions	1.57 interruptions	1.57 interruptions	1.70 interruptions		No Target
	SAIFI Excluding IEEE-Defined Major Events Adjusted to Exclude Catastrophic Days (New $SAIFI_{SQI-4}$)	1.00 interruptions	1.12 interruptions	0.99 interruptions	0.98 interruptions	1.04 interruptions		1.2 interruptions
	SAIDI All Outages Current Year ($SAIDI_{TOTAL}$)	391 minutes	477 minutes	438 minutes	550 minutes	414 minutes		No Target
	SAIDI Excluding IEEE-Defined Major Events Adjusted to Exclude Catastrophic Days ($SAIDI_{SQI-3}$)	148 minutes	175 minutes	145 minutes	136 minutes	165 minutes		155 minutes

New SQI Metrics

Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target
SAIFI for HIC and VP, All Outages, Single Year	1.12	1.31	1.13	1.18	1.35		No Target
SAIFI for HIC and VP Excluding IEEE-Defined Major Events (Adjusted to Exclude Catastrophic Days)	0.75	0.88	0.77	0.74	0.84		No Target
SAIDI for HIC and VP, All Outages, Single Year	249	331	351	427	340		No Target
SAIDI for HIC and VP Excluding IEEE-Defined Major Events (Adjusted to Exclude Catastrophic Days)	105	143	116	111	141		No Target

Demand-Side Management

Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target
Peak Load Management Savings (MW)	N/A	N/A	N/A	N/A	N/A		5
Peak Load Management Savings (MW) Attributable to Residential Customers	N/A	N/A	N/A	N/A	N/A		No Target
Annual Energy Efficiency Savings - Electric (MWh)	314,526	318,316	299,918	237,925	221,001		239,026
Annual Energy Efficiency Savings - Gas (Therms)	4,480,141	3,613,600	3,771,307	3,228,159	4,102,810		3,572,307
Number of Customers Participating in Gas and Electric Energy Efficiency Programs (including Low-Income Programs) Who are from Highly Impacted Communities and Vulnerable Populations	NA	NA	NA	NA	NA		No Target

Electric Vehicles

Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target
Number of Light-Duty Electric Vehicles in Service Territory	NA	NA	NA	NA	NA		No Target
Number of EV Chargers Used in Managed Load Programs or TOU Rates (Single-Family Residential)	NA	NA	NA	NA	NA		5,000
Number of EV Chargers Used in Managed Load Programs or TOU Rates (Fleet)	NA	NA	NA	NA	NA		47
Number of Public Charging Ports Serving HIC and VP	NA	NA	NA	NA	NA		No Target

Greenhouse Gas Emissions

Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target
CO_2 Emissions from Company-Owned Electric Operations	6,515,902	6,217,840	6,080,674	7,406,110	4,793,992		No Target

Advanced Metering Infrastructure

Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target
AMI Bill Read Success Rate - Electric	NA	NA	NA	99.68%	99.76%		No Target
AMI Bill Read Success Rate - Gas	NA	NA	NA	99.40%	99.43%		No Target
Remote Switch Success Rate	NA	NA	NA	NA	99.41%		No Target
Reduced Energy Consumption from Voltage Reductions (kWh)	3,319,625	0	2,127,882	343,748	3,931,329		6,000,000

Additional Equity Metrics

Metric	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2023 Actual	2023 Target
Number of Low-Income Customers Receiving Bill Assistance (Gas and Electric)	NA	NA	NA	NA	NA		No Target
Share of Bill Assistance Customers who are in Highly Impacted Communities and Vulnerable Populations	NA	NA	NA	NA	NA		No Target

Values of "NA" indicate that historical data are not readily available. "No target" indicates that no target has been established for that metric in that year.

*In 2016 and 2017 this metric was the percentage of calls answered in 30 seconds. The target for this metric was 70%. The data reported for these years are consistent with the current metric.

Q. Please discuss the service quality indicators.

A. Service quality metrics and PIMs are a standard feature of MYRPs. The Company already has numerous service quality indicators ("SQIs"). Many of the SQIs have targets and some are linked to PIMs. Compensation of PSE employees is tied to SQI outcomes.

The Company is proposing some changes to its reliability metrics in this proceeding. SAIDI and SAIFI metrics would be computed using only the latest (2012) IEEE-1366 methodology for removing major event day outages. The Company is also proposing its SAIFI metric be calculated similarly to the current SAIDI metric, using the IEEE-1366 methodology with adjustment for catastrophic events. To ensure comparability with past Company values for these SQI metrics, the baseline values would be calculated beginning in 2014, a year subsequent to PSE's implementation of its Outage Management System and Customer Information System.

These reliability metrics would be separately reported for the system as a whole and for highly impacted communities and vulnerable populations. Reliability tends to be higher in highly impacted communities and vulnerable population areas. However, no targets are proposed for these metrics. Additional discussion of the new reliability SQIs can be found in the Prefiled Direct Testimony of Catherine A. Koch, Exh. CAK-1T.

B. Demand Side Management Metrics

Q. Please discuss DSM metrics.

A. DSM should play a major role in meeting PSE's and Washington's decarbonization goals. In the short term, DSM can reduce the need for fossil fuels. In the longer term, it can reduce the need for cleaner but more costly energy alternatives. For these reasons, DSM figures prominently in the Company's Clean Energy Implementation Plan ("CEIP").

Revenue decoupling can reduce the throughput disincentive to embrace DSM and rate designs that encourage it. There are also strong arguments and many precedents for supplementing revenue decoupling with PIMs and other "positive" incentives for utilities to embrace DSM.

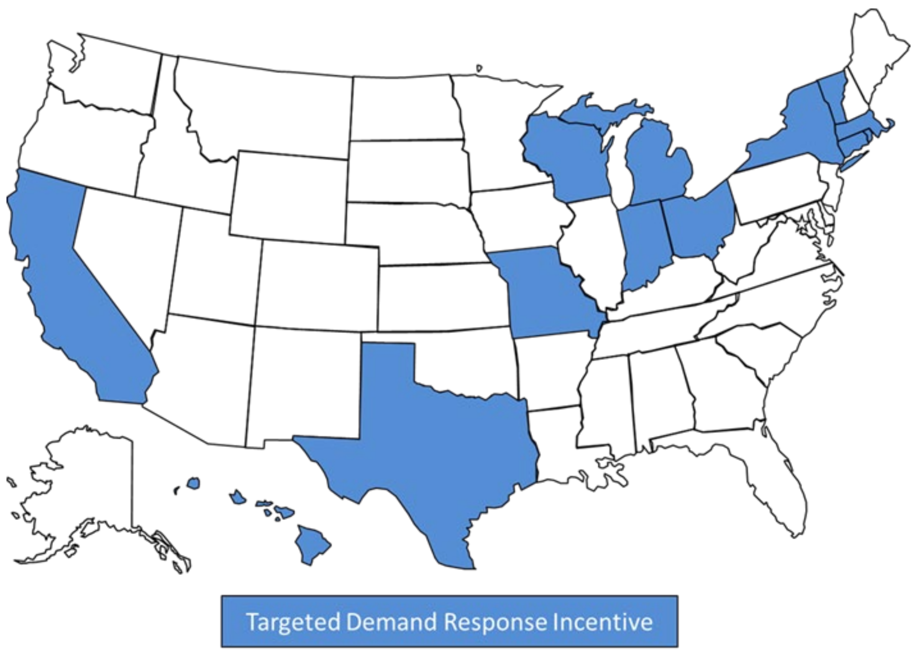
In addition to PIMs for energy efficiency, there is growing national interest in metrics and PIMs that encourage load shaping programs. The need for load shaping is growing with increased reliance on renewable resources, which have intermittent availability that typically doesn't peak when demand does.

Electrification of transportation and space heating can strain system capacity but can also absorb power surpluses when renewable resources are abundant. In parts of the United States, reduction of systemwide peaks can also reduce the share of regional transmission costs that are assigned to a utility.

At least 13 U.S. jurisdictions have PIMs or other targeted incentives to reduce system peak demand. These jurisdictions are depicted in the map in Figure 3 below.

Figure 4

Targeted Incentives for Electric Peak Load Management[3]



Incentives in these PIMs are, variously, based on:

- sharing of estimated net benefits of demand response ("DR") programs;
- return on program expenses;
- compensation for foregone earnings on avoided investments; or
- a pre-established dollar amount or management fee.

[3] Gold, R., Myers, A., O'Boyle, M., and Relf, G. (2020), "Performance Incentive Mechanisms for Strategic Demand Reduction", p. 10.

The reward is typically contingent on meeting or exceeding a threshold level of DR. These PIMs sometimes incorporate capacity savings from EE programs or are complemented by an energy efficiency PIM.

Q. Are some Washington statutes pertinent when considering the need for PSE to have DSM PIMs?

A. Yes. For example, the Energy Independence Act requires large investor-owned electric utilities to "pursue all available [electric] conservation that is cost-effective, reliable, and feasible."[4] A similar mandate applies to gas conservation.[5] The CETA includes a mandate "to pursue all cost-effective, reliable, and feasible conservation and efficiency resources, and demand response".[6]

In addition, the CETA requires that all customers benefit from the transition to clean energy. Burdens to vulnerable populations and highly impacted communities should be reduced. Utilities must routinely report information on the energy burden and energy programs for disadvantaged customers. The CEIPs that utilities have developed pursuant to CETA have included customer benefit indicators ("CBIs").

In the collaborative, some stakeholders opposed demand-side management PIMs on the grounds that the Company has these legislative mandates to pursue cost-effective conservation and peak load management. However, NWEC did propose

[4] *See*, RCW 19.285.040(1).
[5] *See*, RCW 18.28.380.
[6] *See*, RCW 19.405.050(3).

a DR PIM. The metrics in the NWEC-proposed DR PIM were MW of demand reduction from residential customers and the entire portfolio, winter and summer.

Q. Is PSE proposing a demand response PIM?

A. Yes. The Company is proposing an annual metric, target, and PIM to encourage it to obtain DR resources. Eligible DR programs would include direct load control ("DLC"), interruptible (curtailable) load, and/or pricing programs designed to shift load from peak periods and reduce system peak demand. In Chapter 4 of its recently-filed CEIP, PSE explained that it would acquire DR resources primarily through its Distributed Energy Resources / Demand Response Request for Proposal ("DER / DR RFP"), which the Company anticipates filing in early 2022. However, DR resources procured through PSE's own efforts — outside of the competitive procurement process — would also be included.

Q. Would there be any exception to the DR resources eligible for this PIM?

A. Yes. To prevent double-counting of payments, any EV loads that qualify for the EV PIM explained later in my testimony would be excluded from the achievement levels used to establish performance under the DR PIM.

Q. What is the proposed metric for DR?

A. The specific metric to be tracked for DR would be the expected MW reduction in the Company's need for planning reserves for the winter coincident peak demand. Effective DR capacity is a useful shorthand expression for this concept. Each program's effective capacity would be estimated based on pre-established measurement and verification techniques, consistent with any relevant approaches PSE provides in its CEIP.

Q. What are the proposed targets for DR?

A. PSE proposes annual incremental effective capacity targets of 5 MW in 2023, 6 MW in 2024, and 12 MW in 2025. These goals mirror those proposed in the Company's CEIP. Since the Company currently realizes no peak demand reductions through DR programs, these proposed targets represent a significant improvement.

Q. What do you mean by incremental DR capacity in a given year?

A. Suppose a new DLC program is initiated in 2023 and is expected to have the capacity to reduce winter coincident peak demand by 3 MW. The DLC program would then contribute 3 MW towards the Company's 2023 DR achievement level. If the Company added 2 MW of effective capacity through the same program in 2024, that 2 MW would count towards the 2024 DR achievement level.

Q. Please explain the PIM that the Company is proposing for DR.

A. PSE is proposing a PIM that would provide the Company a percentage of its estimated lifetime cost of developing and administering DR programs, including the costs of developing and administering the DER / DR RFP. The Company would receive a payment only if it achieved at least 90 percent of its incremental annual effective DR capacity target. The payment percentage would be 15 percent for achievement levels of 90 percent through 110 percent of the annual target. This percentage would increase to 25 percent for achievement levels over 110 percent and up to 150 percent of the target. No additional reward would be provided for achievement levels in excess of 150 percent of the target. More details regarding the Company's proposed demand response PIM are provided in Exh. MNL-5.

Q. Are the payment percentages of 15 percent and 25 percent reasonable?

A. Yes. Establishing specific payment percentages is ultimately a matter of judgment. But it is important to remember that one of the justifications for a DR PIM is that the utility is potentially foregoing supply-side investments on which it would earn a return. Moreover, the installed costs of the investment would most likely exceed the DR expenses on which the PIM is based. The proposed PIM should be evaluated with that consideration in mind.

If the Company achieves less than 90 percent of its target, it foregoes any earnings opportunity. If the Company achieves at least 90 percent and no more than 110 percent of its target, then it will realize a payment of 15 percent of its expenses, which is roughly twice its weighted average cost of capital ("WACC"). The percentage payment should be higher than the WACC because:

- DR expenses will probably be less than the installed cost of supply-side resources offering similar capacity value;

- the utility deserves a premium payment if it performs well in an important new policy area, i.e., it should be financially better off than if relied on supply-side resources for the same capacity; and

- PSE's achievement levels are less certain than they are for most other utilities, since PSE has little historical experience with DR.

By extension, if the utility performs very well, i.e., achieves more than 110 percent of its target, then it should receive a greater percentage payment to reflect superior performance.

The cap on the total payment (at 150 percent of the target) will protect customers by imposing a ceiling on the total payment in any year.

Q. Why is a reward-only PIM appropriate?

A. The DR PIM focuses on a new performance expectation that goes beyond satisfying customers' basic service requirements. In addition, utilities have a financial disincentive to implement DR programs, as they tend to reduce billing determinants, rate base and earnings.

Q. Does PSE propose to establish any additional DR metrics?

A. Yes. In addition to establishing a metric, target and PIM for the total DR impact on the winter system peak demand, the Company also proposes to track separately the residential contribution to this total. There would be no corresponding target or PIM for the residential class.

Q. Why is PSE not proposing a separate target and PIM for the residential class?

A. The Company has established CEIP goals for the total impact of DR resources on winter coincident peak demand but has not disaggregated this goal by customer class. At this point there is no adequate basis on which to establish a residential-only target.

Q. Why is the Company proposing a target and PIM for the impact of DR on winter coincident peak demand only and not on both summer and winter coincident peak demands?

A. For the foreseeable future, PSE expects to remain a winter-peaking utility. Although PSE is not proposing to establish a summer peak load metric at this time, the Company recognizes that higher air-conditioning saturation in its service territory will increase the importance of reducing summer coincident peak demand as well. Consequently, at some point the Company might propose adding a summer metric.

Q. Is PSE proposing any other DSM-related metrics?

A. Yes. PSE is proposing tracker metrics on its scorecard for the incremental energy savings from its gas and electric energy efficiency programs. These data are routinely reported in other Company filings. Targets have been established for these metrics.

The number of distinct residential and commercial customers participating in electric and gas EE programs who are members of highly impacted communities or vulnerable populations would also be reported. In this calculation, EE programs open to the general public would be counted as well as those that focus on low-income customers. No target is proposed for this metric.

C. Transportation Electrification Metrics

Q. Please discuss the transportation electrification metrics.

A. The transportation sector is the largest source of GHG and hazardous pollutants (e.g., nitrogen oxide) in Washington. These emissions harm the environment and some also degrade visibility and human health. Transportation electrification is accordingly a key goal of the State's clean energy initiative. Detrimental health impacts from nitrogen oxide and particulate vehicle emissions are greatest in the Seattle-Tacoma transportation corridor that PSE serves.

Electric utilities reduce these problems when power generated from clean resources displaces combustion of petroleum products in transportation (and various other kinds of) equipment. Under traditional ratemaking, utilities have some incentives to promote such beneficial electrification. In the short run, electrification can sometimes boost the utilization of excess capacity and thereby create margins from load growth between rate cases. Mobile phone providers have similar incentives to sign customers to service plans and these carriers have a high profile in advertising. In the longer run, electrification can also bolster the need for utility grid investments that enhance earnings.

As described below, utilities nonetheless do not always have strong incentives to aggressively promote beneficial electrification.

- Revenue decoupling promptly passes any margins from electrification to customers.

- Utilities incur costs when EV charging on customer premises increases. These costs may include those for electric vehicle supply equipment such as chargers and other infrastructure upgrades. The costs of EV load growth can also include those for marketing, load management, and customer support. Marketing costs may include discounts on the cost of special services required to support EVs. The cost and hassles of encouraging and then providing service to an additional EV are higher for the medium and heavy-duty vehicles that account for a disproportionately large share of hazardous transportation pollutants.

- EVs must sometimes be charged outside of customers' premises at commercial charging stations. The cost to design, permit, site, construct, own, operate, and maintain these stations is substantial and may not be covered by the resultant revenue. Unprofitable charging stations will be a particular problem in the next few years while the number of EVs on the road is ramping up but potential customers seek assurance that sufficient charging capacity will be available. The utility may get stuck with some of the less profitable locations.

- Even if the utility's forecasted revenue requirement includes a budget for utility EV costs, the growth in this revenue requirement component is disconnected from the growth that actually occurs unless the cost is tracked. Moreover, there will be no funding for EV load growth that exceeds the amount forecasted.

- In the presence of revenue decoupling, the addition of a public charging station or an EV load on customer premises may therefore impose a marginal cost on the utility without corresponding marginal revenue. This weakens the incentive of the utility to support EV load growth. The utility may respond by scaling back marketing efforts, reducing discounts, or by limiting the number of customers that can access its EV services.

- The inclination of a utility not to encourage and support EV growth will be greater the greater are its cost-containment incentives. This problem can be mitigated by tracking the cost of EV services for prompt or deferred recovery. This cost has heretofore been modest for most utilities.

The incentive problem is exacerbated by the fact that decoupling tends to be popular where EVs are popular (e.g., California and New York). The new law encouraging PBR in North Carolina requires that utility proposals include residential revenue decoupling with the following exception:

> The electric public utility may exclude rate schedules or riders for electric vehicle charging, including EV charging during off-peak periods on time-of-use rates, from the decoupling mechanism to preserve the electric public utility's incentive to encourage electric vehicle adoption. [7]

Q. Have any PIMs been approved for EV's in the United States?

A. Yes. Several PIMs have been approved in New York that encourage electric vehicles and other kinds of beneficial electrification. These have typically taken the form of rewards for estimated GHG savings. These precedents are noteworthy since electric utilities in New York operate under revenue decoupling.

Q. Are there some Washington-specific considerations to take into account when contemplating the need for EV PIMs?

A. Yes. I have already mentioned that Washington law sanctions a modest rate of return premium on utility-owned electric vehicle supply equipment. The Company proposes to embrace this incentive, as discussed in the Prefiled Direct Testimony of William T. Einstein, Exh. WTE-1T. The rising low carbon fuel

[7] North Carolina House Bill 951, Part II, Section 4 (a) (c) (2), 2021.

standard that Washington's legislature has approved will boost the funding of utility EV programs but the Company's funds from this source will be modest during the term of the proposed MYRP (2023-25), may only pertain to residential EV customers, and may have restricted uses. Some details of this program have not been finalized.

Stakeholders in the collaborative metric discussions nonetheless maintained that PSE has adequate incentives to promote EVs. They did, however, evince concern about the Company's incentive to manage EV loads cost-effectively. NWEC proposed a PIM for EV load management. The proposed metric was percentage of load shifted to off-peak periods that are attributable to EV tariff offerings.

PSE has a well-established program for supporting the growth of EV loads. In this program, the Company typically owns the electric vehicle supply equipment. Loads of many program participants are managed where this is practicable. The principal focus of managed-load programs to date has been single-family residential customers. PSE plans to expand its EV service offerings during the MYRP, and expansion of EV service to commercial customers and disadvantaged communities are priorities. Managed loads for fleet customers appear to be practicable. However, with the Company having many other goals in the next few years, including better reliability, internal funding for EV load management will be limited.

Q. Is the Company proposing any metrics and PIMs in the EV area?

A. Yes. PSE is proposing a PIM for electric vehicle load management and additional EV metrics that are not subject to targets or PIMs. I explain these proposals below.

Q. What metrics and targets is the Company proposing for the EV PIM?

A. The metric is the number of new chargers installed in a given calendar year and used to provide service under either a load management program or time of use ("TOU") rates, including the Company's proposed Time Varying Rate ("TVR") program. In the operation of the PIM the Company proposes metrics and targets for the following types of chargers:

- Level 2 Chargers used in single family residences;
- Level 2 Chargers used for fleets; and
- DC Fast Chargers used for fleets.

Q. Why does the Company propose to establish metrics and targets for three categories of charger?

A. As I explain later, the Company's proposed PIM is based on the expected net benefits of each new installation. These net benefits vary significantly depending on the type of charger (Level 2 or Fast Charger) and its application (single family residence or fleet). Consequently, it is important to track not only the total number of new chargers, but also the number of chargers in each of the three distinct categories.

Q. Would the targets and PIM be limited to Company-owned chargers?

A. No. The benefits of encouraging customers to charge during off-peak periods are not contingent on Company ownership. Consequently, the Company proposes that the targets and rewards be applied to chargers owned by the Company, customers, or third parties. This approach can incentivize the Company to accommodate chargers owned by others.

Q. During which calendar years would the proposed PIM be effective?

A. PSE proposes that the PIM be effective for calendar years 2023, 2024 and 2025. Of course, the Company may later propose an extension of the PIM, either as approved in this proceeding or with modifications. The Commission's decision in this proceeding should be issued before the first year of the PIM (2023).

Q. Is the Company proposing specific targets in its direct case?

A. No. PSE is still in the process of developing its EV charging targets and anticipates that these targets will be established sometime in the first quarter of 2022. Once these targets are available, the proposed PIM can be set forth in more detail.

Q. Please explain the conditions under which the Company would earn a reward under the proposed PIM.

A. The Company would earn a reward in any given year only if the number of new chargers installed in one or more of the three categories exceeded the target for that category or categories for that year. The reward would be provided only for new installations in excess of the target; in other words, if the target in 2023 was 100 chargers and the Company installed 102 chargers during 2023, then the Company would earn a reward only for the two chargers in excess of the target.

Q. Assuming the Company exceeded its target in one or more categories, how would the specific dollar amount of the reward be established?

A. The Company proposes that the reward be based on a percentage of the expected net benefits of the chargers eligible for a reward. The gross benefits would consist of the:

- avoided energy costs,
- avoided generation capacity costs, and
- avoided transmission and distribution capacity costs.

The expected avoided costs represent the cost impact of the managed load program or TOU pricing on the usage pattern of the chargers. In other words, the avoided costs represent the difference between the cost of serving an EV charging load under a managed load program or TOU rates and the cost of serving the same charger assuming no managed load program or TOU rates.

The costs would consist of the *incremental* administrative and other costs that the Company incurs to serve the charging load under a managed load program or TOU rates. The "other costs" would include any incentive payments to customers to encourage them to place their charging loads on managed load programs or TOU rates.

I emphasize that these incremental costs would exclude the majority of the costs of developing and administering the load management or TOU pricing option. Instead, the costs used to calculate net benefits would be limited to the incremental costs of serving an additional charger under the load management program or TOU rates.

The expected benefits and costs per charger would be estimated over five years. The present value of the five-year stream of costs would then be subtracted from the present value of the stream of benefits to yield a single dollar reward for each installed charger in excess of the target. A distinct dollar award per installation would be established for each of the three categories of chargers.

Q Why do the costs and benefits in the proposed calculations exclude many of the impacts of EV load growth, such as the investment cost of the charger or the environmental benefits of reducing net carbon emissions?

A. It is important to remember that the purpose of this proposed PIM is not simply to encourage more chargers per se, but to encourage customers that do install chargers to charge during off-peak periods — when energy and capacity costs are lower. As mentioned previously, this usage shift was a priority for stakeholders in the metrics collaborative as well. There are other mechanisms (such as a premium return on equity of 200 basis points for EV-related investments) that encourage the Company to install more chargers. Consequently, the impacts used to establish the reward are limited to the impacts of encouraging off-peak charging. Those impacts do not include the net environmental benefits of reducing the emissions from internal combustion engines or the cost of installing a charger.

Q. Why is it appropriate to use expected net benefits as a basis for the reward?

A. One of the primary advantages of basing the reward on a percentage of net benefits is that customers are expected to benefit when the Company exceeds its target(s) as long as the percentage reward to the Company is less than 100 percent.

A potential disadvantage of using net benefits is that deriving the actual avoided costs can be very time-consuming and administratively burdensome. Such a derivation would require analyses of actual load shifts and actual avoided costs based on these load shifts. To avoid these potentially high costs, the Company proposes to use pre-established estimates of load shifts and the concomitant avoided costs over a five-year period. I believe any reduction in accuracy attributable to using estimates is outweighed by the increased simplicity and reduced costs of administering the PIM.

Q. Why is a reward-only PIM structure appropriate in this case?

A. The justification is similar to the justification for using a reward-only structure for DR. In both cases the Company is challenged with a new performance expectation that goes beyond satisfying customers' basic service requirements. In addition, in both cases the Company is being encouraged to take steps that tend to reduce rate base and earnings.

Q. You explained how the Company's dollar reward would be based on a percentage of expected net benefits. Is the Company proposing a specific percentage reward in its direct case?

A. No. As explained previously, the Company will not have targets for EV installations until later in this quarter. Similarly, the Company also anticipates developing later in this quarter the estimated costs and benefits that would be used to establish the award per charger. Until this information is available, the Company cannot calibrate an appropriate percentage. The Company plans to propose specific percentages later in this proceeding, when more information is available.

Q. Are you providing an illustrative example of the proposed EV PIM you explain above?

A. Yes. Exh. MNL-5 provides a summary of how the PIM would be developed.

Q. Please summarize the Company's proposed EV PIM.

A. The Company proposes a reward-only PIM based on the number of new EV chargers installed in a given year and used to provide service under either a managed load program or TOU rates. The reward would apply to all installations in excess of the target established for that year and would be based on a pre-determined estimate of lifetime net benefits per charger. Separate targets and rewards would be established for single-family residences using Level 2 chargers, fleets using Level 2 Chargers, and fleets using Fast Chargers. While I explained the conceptual approach and justification of the proposed PIM above, the Company will not be positioned to propose specific targets and sharing percentages until later in the first quarter of 2022.

Q. Please describe the EV tracker metrics the Company is proposing.

A. The MYRP scorecard would report two EV-related tracker metrics. One is the estimated number of light-duty plugin electric vehicles (battery-only or hybrid) in the Company's service territory. This would be calculated using Washington Department of Licensing data on EVs registered in zip code tabulation areas in which PSE offers electric service. The Company also proposes to track the number of publicly-available charging ports in highly impacted communities and vulnerable populations. PSE will continue to report a wider array of EV metrics in other venues.

D. Emissions Metrics

Q. Please discuss the emissions metrics the Company is proposing.

A. Many industry observers believe that utilities have inadequate incentives to contain their impact on the environment. Metrics can track utility activities that damage the environment. Relevant metrics include emissions of GHGs from utility generation and vehicles, sodium hexafluoride emissions, and natural gas leaks and line losses.

PSE is preparing to comply with the decarbonization goals of CETA which call for the retail sales of each Washington electric utility to be GHG neutral by 2030. The Company recently detailed a strategy for achieving this in its CEIP. PSE is proposing to track the metric tons of Scope 1 emissions from Company-owned generation. The year-to-year GHG emissions from the Company's generation are volatile, driven by external business conditions such as weather, the business cycle, and the availability of hydroelectric and other kinds of renewable energy resources. Accordingly, no target or PIM are proposed. The tracking of emissions from PSE-owned generation is discussed further in the Prefiled Direct Testimony of Joshua J. Jacobs, Exh. JJJ-1T.

E. Advanced Metering Infrastructure Metrics

Q. Please discuss the advanced metering infrastructure metrics.

A. In a period when many utilities are investing sizable sums in AMI and other smart grid facilities, regulators and stakeholders want to know if these facilities are functioning well and well-utilized. Potential benefits from AMI include increased customer participation in load shaping programs such as TOU pricing. The benefits of AMI also include reductions in distribution system voltage, the duration of outages, consumption on inactive meters, unaccounted-for energy use, and meter-reading costs.

AMI metrics are monitored in several jurisdictions. These metrics have addressed several dimensions of AMI performance, including AMI functionality, utility cost savings, customer engagement, and environmental and load-management benefits.

There are a few precedents for AMI-based PIMs. In New York, for example, Consolidated Edison had a PIM to appraise their AMI customer awareness strategy through customer surveys. In Illinois, Commonwealth Edison has PIMs that address the achievement of reductions in the number of estimated bills, energy consumption on inactive meters, unaccounted for energy, and uncollectible bill expenses.

The UTC's decision in the recent Avista rate case indicates that they have an interest in AMI performance metrics.

> To demonstrate the benefits of AMI, Avista should be required (1) to develop and report further analyses of the use cases: TOU rates, real-time energy use feedback for customers, behavior-based programs, data disaggregation, grid-interactive efficient buildings, CVR or volt/VAR optimization; (2) to craft and report plans for achieving benefits through each of these use cases; and (3) to develop and propose AMI performance-based regulation metrics and measurements that the Commission might apply, and specifically such metrics and measurements for each of these use cases. [8]

PSE is in the middle of a systemwide AMI buildout. This makes AMI metrics topical but limits the availability of data. The Company is proposing to include three AMI metrics in its MYRP scorecard. These metrics address the functionality of AMI and its impact on system voltage.

- <u>Bill Read Success</u>. The most fundamental job of AMI is to automatically forward data on customer billing determinants. The proposed Bill Read Success metric would measure whether the AMI delivers a meter read to PSE's data system, as expected each cycle. This would be calculated separately for gas and electric meters. A 99.5% success rate target is proposed for each plan year beginning in 2024.

- <u>Remote Switch Success</u>. AMI makes it possible to turn service off and on quickly and without truck rolls. The proposed Remote Switch Success metric would measure the functionality of the switch when a command is made from the command center by PSE. Calculation would be limited to customer-initiated requests. This metric would be reported only for electric service. The proposed target is a 99% success rate beginning in 2024.

- <u>Voltage Reduction</u>. The voltage on a distribution circuit must attain a minimum standard for every customer. AMI improves knowledge of the voltage at which each customer on a distribution circuit is served. This can make it possible to reduce voltage on the circuit at the substation that serves it. The proposed Voltage Reduction metric would measure the reduction in KWh accomplished. The proposed target for 2023 is 6,000,000 kWh.

[8] WUTC (2021), Final Order 08/05, p. 127.

No AMI PIMs are proposed. The Company will report additional AMI metrics routinely in other venues. AMI metrics are discussed further by Company witness Catherine A. Koch, Exh. CAK-1T.

F. Additional Equity Metrics

Q. Please discuss any additional equity metrics.

A. I have already noted the metrics on the scorecard for reliability, public EV chargers, and EE program participation in highly impacted communities and vulnerable populations. The affordability of the Company's service to low-income customers is another key area of concern to policymakers. The Company also proposes two affordability metrics. One is the number of distinct customers receiving bill assistance from qualified low-income programs. The qualifying programs would include the low-income energy assistance program ("LIHEAP"), PSE's Home Energy Lifeline Program ("HELP"), the Salvation Army warm home fund, PSE's proposed arrearage management program, and the proposed bill discount rate. The Company will also report the share of these bill assistance customers who are members of highly impacted communities and vulnerable populations.

Customer benefit indicators, many of which have an equity component, will be reported in the annual reporting required under Washington Administrative Code 480-100-650(3).

VI. APPRAISAL OF THE COMPANY'S MYRP PROPOSAL

Q. What are some reasonable criteria for appraising MYRP proposals?

A. An appraisal of a proposed MYRP should encompass several considerations. One is its fairness. A second is its effect on utility performance incentives. A third is its effect on regulatory efficiency. It is also pertinent to consider the extent to which SB 5295 ties the hands of the Commission in approving MYRPs.

Q. Please discuss the fairness of the Company's proposal.

A. I believe that the Company's proposal is fair on balance. There are some benefits for PSE. For example, revenue growth would be based on the Company's financial plan in the two "out" years, as well as the first year, and would be subject to an adjustment for unforeseen inflation. Revenue decoupling would continue to reduce the risk of volatility in billing determinants. Subject to statutory limitations, PSE could file a rate case if it underearns.

However, the framework also provides extensive customer protections, including:

- The Commission would decide the extent to which it would fund PSE's budgeted cost growth. Moreover, the Company would be obliged to operate under the Commission-approved revenue requirement for at least two years.
- Revenue to reimburse PSE for the annual cost of capital expenditures it made during the plan may be refunded to customers if the assets are later found not to be used and useful or their cost is deemed imprudent. This provision was noted above to be common to some other approved RAMs that are based on forecasts.
- The ESM would asymmetrically favor customers. The entirety of weather-normalized earnings in excess of a modest 50 basis point dead band would

be reserved for refunds to customers or another determination by the Commission. In contrast, many approved MYRPs have wider dead bands and/or afford utilities a share of surplus earnings beyond the dead band. Some plans do not have an ESM. In the event of underearning, PSE would absorb the entirety of any ROE shortfall until and unless it is granted some rate relief in year three after a rate case. In contrast, in some approved MYRPs underearnings are automatically shared with customers.

- PSE would absorb the risk of fluctuations in loads for some large-volume customers.
- Rate growth would be more predictable.
- The term of the MYRP would only be three years.

Q. Please discuss the impact of PSE's MYRP on cost control incentives.

A. The Company's cost control incentives would be strengthened by the MYRP. Under continued COSR, PSE would be free to file a rate case at any time. Given its need to modernize the grid, improve reliability, and supply cleaner energy, the Company would likely file rate cases frequently. It would likely also continue to be subject to earnings sharing.

The proposed MYRP would in contrast provide significant incentives to contain O&M expenses since revenue growth for these kinds of costs is not linked to actual cost growth between rate cases. The Company would absorb the annual cost of any capex overspends.

The Company's ability to file a rate case during the MYRP is a fairly unusual feature of the framework. However, there are similar provisions in the new PBR law in North Carolina. Other approved MYRPs have off-ramp provisions. Moreover, the proposed provision that allows PSE to file a rate case is unlikely to trigger a rate case. Given the three-year plan period, the Company would likely file a rate case at the beginning of Year 3 anyway in order to have new rates effective upon the expiration of the plan.

I would also note that this provision only gives PSE the *right* to file a rate case, the Company is not required to file a rate case. In my experience, small and temporary underearnings rarely prompt a utility to file a rate case. The decision to file a rate case is based on several factors including the magnitude of the earnings deficiency, forecasted changes in costs or revenues, expectations of changes in the authorized rate of return resulting from a potential rate case, the ability to seek supplemental revenue through deferrals or cost trackers, and political considerations. PSE might not file a case even if it is eligible to do so because the situation is expected to be temporary, and it is in the Company's long-term interest to make MYRPs work.

Q. Please discuss the impact of PSE's MYRP on regulatory efficiency.

A. MYRPs should improve the efficiency of regulation and the Company's plan can accomplish this, first and foremost by reducing the frequency of rate cases. Regulatory resources would thereby be freed up to focus more on utility capital expenditures, rate designs and miscellaneous generic issues. This is a notable advantage in a period of rapid change when the UTC must contend with a swirl of issues. Of course, the magnitude of these benefits will depend on the other filings and processes that are required as part of, or in conjunction with, the MYRP.

Q. Please discuss the attention PSE's MYRP gives to other goals.

A. The goals of utility regulation extend beyond ensuring that the Company provides service of reasonable quality at a reasonable price. In Washington, the impact of utility operations on the environment and disadvantaged groups are of special interest. The Company's MYRP proposal encourages attention to these other goals through revenue decoupling and its scorecard of metrics and PIMs. PSE is, additionally, subject to legislative mandates to decarbonize its energy supply, pursue cost-effective DSM, and spread benefits of the energy transition equitably.

Q. Is the Commission hamstrung by SB 5295 in its ability to approve an MYRP that it believes to be just and reasonable?

A. No. Legislation in several states has detailed a particular approach to Altreg and provided regulatory commissions limited discretion to accept a different regulatory approach. The Washington MYRP law, in contrast, gives the Commission significant latitude and affords it considerable discretion over the design of any MYRPs that are adopted.

VII. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXH. MNL-5
DOCKETS UE-22___/UG-22___
2022 PSE GENERAL RATE CASE
WITNESS: MARK NEWTON LOWRY

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**Docket UE-22____** **Docket UG-22____**

FOURTH EXHIBIT (NONCONFIDENTIAL) TO THE PREFILED DIRECT TESTIMONY OF

MARK NEWTON LOWRY

ON BEHALF OF PUGET SOUND ENERGY

JANUARY 31, 2022

Demand Response PIM

Metric

The metric for the demand response PIM is the expected MW reduction in the Company's need for planning reserves to meet the winter coincident peak demand which is attributable to eligible demand response ("DR") initiatives, as adjusted for the planning reserve margin and losses to represent impact at generation level. Each year effective incremental DR capacity is the impact of all incremental DR resources obtained in that year. Effective DR capacity is based on the impact of DR on the generation capacity required to meet the Company's planning reserves requirement, not the DR resources that are actually called upon during any particular winter.

Reporting of the effective DR capacity will be consistent with the Tracking and Reporting section of Chapter 7 of the Company's CEIP, which was filed on December 17, 2021**.**

Eligible Initiatives

The eligible DR initiatives include direct load control, curtailable or interruptible load, and pricing programs whether initiated as a result of competitive solicitations or internal Company initiatives. Costs and load savings from PSE's electric vehicle managed load program will be excluded.

Targets

Year	Incremental Demand Reduction Target at Generation
2023	5 MW
2024	6 MW
2025	12 MW

PIM Description

Each year the Company can earn a payment equal to a percentage of the total projected costs attributable to DR resources which are added in that year, depending on the incremental effective DR capacity achieved. These incremental DR resources can be obtained from new DR programs or from additional load for a DR program implemented in a prior year.

The costs of the additional DR resources will be estimated over the life of the resource or 10 years, whichever is shorter. The stream of estimated annual costs will be discounted at the weighted average cost of capital. To be eligible for any payment the Company must achieve at least 90 percent of its target. The payment percentage increases as performance improves.

The projected costs include, but are not limited to, the Company's own DR-related setup costs, O&M expenses, equipment costs, marketing costs, customer incentives and administration costs for the Distributed Energy Resource / Demand Response Request for Proposal. Preliminary estimates of DR program costs are provided in Appendix F-2 of the Company's CEIP, which was filed on December 17, 2021**.**

For purposes of the demand response PIM the Company will include one-time costs (e.g., equipment costs, setup costs, etc.) attributable to a new program during the first year the Company offers the program, as long as the PIM threshold of 90 percent of the target is achieved. If the Company does not achieve the 90 percent threshold during the first year the program is offered, the one-time costs for that program can be included in a subsequent year when the Company does achieve at least 90 percent of its target.

PIM Bands

The following table details how the reward varies with the incremental effective DR capacity achieved.

Year	Achievement as % of Target	Corresponding Incremental MW	Reward as % of Program Costs
2023	< 90%	< 4.50 MW	0%
	90% - 110%	4.50 MW - 5.50 MW	15%
	>110%	> 5.50 MW	25%
2024	< 90%	< 5.40 MW	0%
	90% - 110%	5.40 MW - 6.60 MW	15%
	> 110%	> 6.60 MW	25%
2025	< 90%	< 10.80 MW	0%
	90% - 110%	10.80 MW - 13.20 MW	15%
	> 110%	> 13.20 MW	25%

The Company will not incur a penalty under this PIM, regardless of its achievement levels.

PIM Cap

No additional payment will be provided for achievement levels over 150% of the targets.

EV Managed Load PIM

Metric

The metric for this PIM is the number of EV chargers used under managed load programs or time-of-use ("TOU") rates.

Eligible Chargers

Eligible chargers include those installed for single-family residential or fleet customers in the Company's service territory which are used in managed load programs or (in the case of residential customers) TOU rates. Eligible chargers include those owned by the Company, the customer, or a third party.

Targets

Year	Number of Managed-Load and TOU-Rate Chargers		
	Single-Family Residences	Fleets L2 Charger	Fleets DC Fast Charger
2023	___	___	___
2024	___	___	___
2025	___	___	___

PIM Description

In each year of its MYRP, Puget Sound Energy can earn a payment for exceeding the target number of chargers for single-family residences and fleet customers that are served under managed load programs or (in the case of residential customers) TOU rates. The targets are the number of chargers that the Company plans for each year on the basis of the approved budgets for these programs.

The payment is equal to the number of installations in a given year in excess of the target times a pre-determined payment rate per installation. The payment rate per installation is the difference between the estimated present value of the five-year stream of incremental benefits and incremental costs attributable to serving a given type of charging load in a given year under a managed load program or TOU rates. A separate payment rate will be established each year for each of the three categories of chargers. These estimated payment rates are not subject to reconciliation to reflect any after-the-fact derivations of benefits and costs.

The benefits include avoided energy, avoided generation capacity, and avoided transmission and distribution capacity costs. The costs include any incremental expenses incurred to serve the charging loads under managed load programs or TOU rates.

The payment formulas are as follows.

Residential Program Reward
= Award Rate^{Residential} x max[0, (Actual Number of Chargers – Target Number of Chargers)^{Residential}]

Fleet Program Reward^{L2}
= Award Rate$^{Fleet\ L2}$ x max[0, (Actual Number of Chargers – Target Number of Chargers)$^{Fleet\ L2}$].

Fleet Program Reward^{DC}
= Award Rate$^{Fleet\ DC}$ x max[0, (Actual Number of Chargers – Target Number of Chargers)$^{Fleet\ DC}$].

The Company will not be penalized if it fails to achieve its target number of chargers.

Illustrative PIM Derivation Based on Hypothetical Data

Year	Target Installations	Actual Installations	Actual Minus Target	Reward per Installation	$ Reward
2023	100	105	5	$100	$500
2024	120	115	-5	$105	$0 (Actual < Target)
2025	130	150	20	$110	$2200