PUGET SOUND ENERGY

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UE-210804

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Filed via Web Portal

Amanda Maxwell
Executive Director and Secretary
Washington Utilities and Transportation Commission
621 Woodland Square Loop SE
Lacey, WA 98503

Re: Docket UE-210804: Comments of Puget Sound Energy

Dear Ms. Maxwell:

Puget Sound Energy ("PSE") respectfully submits these comments in response to the Washington Utilities and Transportation Commission's (Commission) November 4, 2021 Notice of Opportunity to File Written Comments (Notice) in the above-captioned docket. The Notice solicits comments on the topic of cost-effectiveness of distributed energy resources (DERs) and asks whether additional Commission guidance is necessary on this topic in light of the Clean Energy Transformation Act (CETA). PSE appreciates this opportunity to comment and looks forward to participating in Commission workshops on this matter.

<u>Responses to Notice Questions</u>

1. **Do the policy goals identified in Table 3 appropriately and sufficiently cover the applicable policy goals for Step 1 of the process to develop a Commission-specific primary test for DERs?**

PSE agrees that regardless of whether the Commission seeks to create a new, jurisdictional-specific cost-effectiveness test or review and refine existing tests, such as the modified Total Resource Cost (TRC) test, articulating applicable policy objectives is a necessary first step. In PSE's experience, this first step of articulating goals is important, but also less critical to the development of a cost-effectiveness test than the steps of identifying impacts to implement those objectives, designing consensus methods to quantify and measure those impacts, and including quantified impacts in the resulting benefit-cost analysis in practice. Accordingly, PSE encourages the Commission to devote sufficient time for stakeholders to do the intensive analysis and quantification of impacts in order to incorporate goals into evaluation processes.[1]

Ultimately, the goals in Table 3 are broad and appear to capture many of Washington's current high level policies. But given their broad scope, it may be beneficial to first discuss goals in a workshop setting, so stakeholders can determine whether additional goal refinement, organization, or prioritization may be appropriate. PSE looks forward to these conversations.

2. **Do any of these policy goals apply to some DERs but not others? Please discuss the advantages and disadvantages of applying some of the policy goals to different DER types.**

At a high level, PSE sees value in the continuity of applying the same cost-effectiveness *framework* across evaluation processes for different resource types. This will ensure that costs and other per-unit values or impacts (e.g., avoided generation capacity) are evaluated consistently. However, there will also likely be important nuances or factual considerations to consider for certain DER types. And these nuances may require unique applications of the overarching cost-effectiveness framework. For example, it may be necessary to quantify discrete direct and indirect benefits and costs associated with specific DER types in different ways. Certain policy goals may also need to be interpreted in light of unique DER attributes.

Transportation electrification (TE) is an illustrative example, particularly as it relates to the goal of developing "lowest reasonable cost resources" in Table 3. PSE recognizes the importance of this goal. But as highlighted in response to question three below, TE benefits include items like incremental operations and maintenance savings, avoided direct carbon costs, and other benefits not tied directly to the utility's sale of electricity. Thus, understanding how the goal of developing lowest reasonable cost resources applies to evaluation of TE programs is important. Electric vehicles are generally a source of consumption rather than a source of renewable generation or conservation. Yet they also have potential load flexibility (e.g., demand response) and vehicle-to-grid (e.g., battery storage) applications, which means benefit-cost analyses of any kind must include guidance on how to quantify and value these impacts and other intangibles.

Other DERs—such as demand response, distributed generation, and distributed storage—may require a similar approach, whereby specific direct and indirect benefits are measured differently or in unique ways for different DER categories. PSE looks forward to exploring these and other issues in a manner consistent with the NSPM framework. However, PSE emphasizes that simply creating a new jurisdictional-specific test does little to address these hard questions on its own. Challenging and time-intensive work must still be done to implement any identified policy goals through accurate identification and quantification of impacts. And as the NSPM notes, this work can also be done in the context of revisiting existing cost-effectiveness tests.

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[1] *See* National Standard Practice Manual for Benefit-Cost Analysis of DERs (NSPM) at page 65, stating that Step 1 of the NSPM process (*Articulate Applicable Policy Goals*) "may be challenging to apply where jurisdictions have different policy goals for different DER types, making it difficult to establish a single test for all DER types."

3. **The cost-effectiveness tests currently employed by Washington investor-owned utilities are the modified total resource cost test and the utility cost test. For stakeholders to have a full understanding of current practice, utilities should provide a table of utility impacts (costs and benefits) currently used for evaluating cost-effectiveness of DERs in response to this question. Specifically, the IOUs should indicate what impacts are currently included for the following different DER resources: energy efficiency, demand response, distributed generation, distributed storage, building electrification, transportation electrification, or other DERs identified in a planning process.**

Energy Efficiency

PSE currently conducts two cost-effectiveness tests to measure whether the benefits obtained by a demand side resource meet or exceed the costs to obtain the resource. PSE's primary test is the TRC test, as modified by the Northwest Power and Conservation Council (Council). Under this test, PSE must demonstrate that the cost-effectiveness tests presented in support of its programs and portfolio are in compliance with the cost-effectiveness definition in RCW 80.52.030(7) and system cost definition in RCW 80.52.030(8), and incorporate quantifiable non-energy impacts, a 10 percent conservation benefit, and a risk adder consistent with the Council's approach. An outline of the major elements of the Council's methodology for determining achievable conservation potential, including the TRC test, is available on the Council's website.

In addition to the Council-modified TRC test, PSE must also provide portfolio calculations of the Program Administrator Cost test (also called the Utility Cost (UC) Test), the Ratepayer Impact Measure test, and the Participant Cost test, described in the National Action Plan for Energy Efficiency's study "Understanding Cost-effectiveness of Energy Efficiency Programs." The study is available here on the website of the United States Environmental Protection Agency.

Additionally, overall conservation cost-effectiveness must be evaluated at the portfolio level, and costs included in the portfolio level analysis include conservation-related administrative costs.[2] For the UC Test, the Ratepayer Impact Measure test, and the Participant Cost test, PSE must consult with its Conservation Resource Advisory Group (CRAG) to determine when it is appropriate to evaluate measure and program level cost-effectiveness. All cost-effectiveness calculations assume a Net-to-Gross ratio of 1.0, consistent with the Council's methodology. More information on both the UC Test and the modified TRC test are available in PSE's 2022–2023 Cost-Effectiveness Overview, which was filed as Exhibit 2, Supplement 1 in PSE's most recently submitted 2022–2023 Biennial Conservation Plan.[3]

[2] Pursuant to WAC 480-109-100, PSE must exclude low-income weatherization programs from the portfolio-level cost-effectiveness calculations mentioned above.

[3] For more information, please see PSE's filing in Dockets UE-210822 and UG-210823.

As the name suggests, the UC Test only considers utility costs and utility benefits for the construction of the benefit-cost ratio. The basic costs and benefits included in the calculation of the UC Test are listed below:

Costs	**Benefits**
Program overhead costs[4]	Avoided cost of energy (e.g., market cost of energy, line losses, and the Social Cost of Greenhouse Gases)
Incentives provided to customers who purchase an energy efficient measure	Avoided costs of capacity (e.g., deferred transmission and distribution expense, total annual fixed cost of generating capacity)
Other program specific costs[5]	

The TRC Test, by contrast, views demand side resource acquisition from a total cost perspective. The test determines the benefit of the demand side resource given the total cost to all parties involved, not simply the acquisition cost to the utility. PSE is required to run the TRC for both gas and electric programs. The TRC considers all costs, including those incurred by the utility, by the customer and by others who may have contributed. The costs and benefits included in the calculation of the TRC test are listed below:

Costs	**Benefits**
Program overhead cost (marketing, outside services, internal labor and overhead, miscellaneous expenses)	Avoided cost of energy (market cost, line losses, peak generation value, and Social Cost of Greenhouse Gases)
Incentives provided to customers who purchase an energy efficient measure	Avoided costs of capacity (deferred transmission and distribution expense, total annual fixed cost of generating capacity)
Measure costs to customers, either full or incremental, of acquiring the efficient	Conservation credit (i.e., a 10% adder provided by the Northwest Power Act to

[4] These costs include the costs of marketing (advertising, bill inserts, campaigns, radio advertisements, etc.), outside services (all costs of outside vendors), internal labor and overhead (PSE employee expenses and PSE incurred overhead costs), and miscellaneous expenses related to program activities (costs for event prizes, car rentals, PSE employee hotel rooms, etc. which are incurred as a result of operating the program).

[5] Some programs have additional costs associated with them, such as the additional cost of natural gas on an electric to natural gas fuel conversion program. These costs need to be included in the costs for the UC Test calculation.

Costs	**Benefits**
equipment or services, net of any incentives provided by the utility	advantage energy conservation over generation resources
Other specific program costs	Non-energy impacts (e.g., savings on non-energy related items, such as: O&M savings; water and sewer savings; health and savings benefits; avoided debt and arrearages; noise light, and thermal comfort; productivity and revenue; avoided spoilage losses; and reduced fire and insurance losses)
Negative non-energy impacts	Cost of upstream carbon emissions

Demand Response, Distributed Generation, and Distributed Storage

PSE used a DER benefit-cost analysis (BCA) model to quantify potential grid, customer, and societal benefits in the development of its draft Clean Energy Implementation Plan (CEIP). For further details on the DER BCA model, please see CEIP Appendix D, DER Suite Selection and Evaluation. In brief, PSE mapped costs and benefits to the societal and participant cost tests, following guidance from the NSPM to evaluate different suites of DERs. Given CETA's goals to achieve a 100 percent clean electricity supply and inclusion of safeguards to protect consumers from excessive rates or unreliable service, PSE determined that the Societal Cost Test (SCT), which includes electric utility systems, host customers, and societal impacts, aligns with these objectives. As a secondary cost test, PSE used the Participant Cost Test (PCT) to prioritize concepts with favorable customer economics; that is, concepts customers will be more likely to adopt if the economics are sound. Once these tests were selected, PSE applied each test based on the suite methodology articulated in Appendix D.

Below are the host customer, utility, and societal costs and benefits quantified. The BCA model was constructed to quantify each of these costs and benefits, when applicable, and apply cost tests consistent with the NSPM.

Costs	**Benefits**
Utility initial capital outlay	Utility reduced system peak capacity
Utility capital replacements	Utility coincident transmission peak capacity
Utility grossed-up return on asset base	Utility coincident distribution peak capacity
Utility common O&M costs	Utility reduced transmission peak capacity

Costs	**Benefits**
Utility PPA participation payments	Utility reduced distribution locational peak capacity
Utility owned/operated battery energy storage system charging costs	Utility PV generation market value
Host customer initial capital outlay	Utility flexibility benefit and frequency response offset value
Host customer capital replacements	Customer backup power savings
Host customer program participation costs	Societal greenhouse gas benefits
Host customer battery energy storage system market purchase charging costs	
Host customer O&M	

In addition to the use of the cost tests as described above, PSE also evaluated and scored each DER program based on its newly developed customer benefit indicators (CBI). This provided an additional level of evaluation on the specific CBIs developed for CETA implementation. The CBI scoring was used in conjunction with the SCT and PCT to evaluate and select DER programs for the CEIP. It is important to note that PSE identified additional benefits as future CBIs, such as job creation, energy security, and other non-energy impacts, that were difficult to quantify and therefore were not included in the development of the current CEIP. PSE intends to continue the development and refinement of the CBIs and the associated measurement and application.

Transportation Electrification

In developing the design and budget for each of the new and expanded programs that were part of PSE's TE Plan, which was filed in Docket UE-210191 on March 19, 2021, PSE incorporated feedback from customers and stakeholders, conducted benchmarking of other utility electric vehicle programs, and evaluated lessons learned from PSE's Up & Go Electric pilot experiences as well as from other utility EV program leaders. Pairing this effort with analysis of system costs and revenue from electric vehicle adoption, PSE TE Plan programs offer expanded support of electric vehicle adoption while balancing cost impacts to all customers. The costs and benefits included in the calculation of TE cost-effectiveness are included below:

Costs	**Benefits**
Incremental vehicle costs	Vehicle operations and maintenance savings

Costs	**Benefits**
Electric vehicle supply equipment costs	Avoided direct carbon costs
Marginal energy costs	Avoided gasoline costs
Marginal generation capacity costs	Federal tax credits
Ancillary services or other energy supply costs	Revenue from electric transportation
Transmission and distribution costs	

4. **Are there specific questions related to cost-effectiveness from the NSPM or other sources that are necessary to answer during the course of this investigation? For example, choice of discount rates or incremental cost calculations? Please describe why answers to these questions are necessary to develop a Commission jurisdiction-specific test.**

Yes. PSE agrees that the choice of discount rates and incremental cost calculations are important factors. As the NSPM notes, the choice of discount rate can have a large effect on results. Generally, a higher discount rate gives more weight to short-term benefits and costs, whereas a lower rate gives greater weight to long-term impacts.[6] Additional major drivers of cost-effectiveness tests include: the avoided cost of energy; avoided costs of capacity; program overhead costs; customer costs; program incentives; non-energy impacts; measure life; and the load shape used in the calculation of avoided costs. PSE looks forward to discussing these and other topics during workshops.

In addition, it is possible that certain impacts potentially developed to achieve the policies in Table 3 may be difficult to quantify. Accordingly, PSE looks forward to discussing whether and how certain policy goals should be prioritized, so that utilities can research implementation of these goals further. To this end, the Commission might also consider providing guidance on how stakeholders should begin working to develop standard or prescribed values, adders, or adjustment values to implement policies, similar to the 10 percent cost advantage that the Northwest Power Act provides for energy efficiency. Discussion of these topics alone could take significant time.

5. **This Docket is focused on electric utility system cost-effectiveness changes due to CETA. Although CETA does not apply to gas utility systems, other recent policy changes indicate a need to examine current cost-effectiveness practices. Please**

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[6] NSPM at 22, 31.

describe the advantages and disadvantages of addressing both electric and natural gas cost-effectiveness in this Docket to ensure a consistent framework is used.

CETA does not apply to natural gas utilities, and it is not clear which other recent policy changes this question contemplates. As it relates to natural gas, however, it may be helpful for the Commission to facilitate a discussion about how utilities should evaluate situations where customers switch from natural gas to electricity. Traditionally, such activities have not been determined to be cost-effective because under the existing NSPM cost-effectiveness framework because reducing natural gas consumption, for example, results in additional electric load (i.e., negative electric savings). Accordingly, it may be helpful for the Commission and stakeholders to discuss ways in which existing cost-effectiveness methods can be modified or refined so that utilities can more holistically evaluate opportunities for reducing peak energy needs and achieving emissions reductions in a technology-agnostic manner.

6. **The Commission is seeking stakeholder input to develop a workplan for completing this investigation. After reviewing the NSPM, the Commission will convene a series of stakeholder workshops and solicit multiple rounds of stakeholder comments to develop a new primary, jurisdiction-specific test and address other topics raised during stakeholder meetings. We anticipate this process will include five to seven meetings. Please provide feedback on this proposed process, including reasonable timeframes for completion.**

At this early stage of the proceeding, PSE submits that it may be premature to assume that the most logical outcome is to create a new, primary jurisdictional-specific test. As noted above, it may be prudent to explore whether modifications to existing tests, which in some cases already include many non-energy impacts and other indicators relevant to the policy goals articulated in Table 3, might achieve the same ends. PSE already uses the NSPM framework as the basis for its cost-effectiveness tests, and most of the principles identified in Table 3 are in line with what is already considered. There may indeed be opportunities to consider or include additional policy objectives, but that does not necessarily require the creation of an entirely new test.

Procedurally, however, PSE questions whether “five to seven meetings” (presumably virtual only) will be sufficient for the Commission and stakeholders to fully navigate the issues that will arise under the NSPM framework. As noted earlier, developing a new test does not necessarily avoid any of the challenges associated with identifying, quantifying, and monetizing the impacts that ultimately measure the achievement of any identified policy goals. Nor does it mean stakeholders can avoid a majority of the other intensive technical discussions that will require substantial time and resources. PSE has already been using the NSPM framework to develop cost tests for DERs, both as part of its CEIP development process and in other settings, and PSE looks forward to leveraging this experience in this setting.

7. **We anticipate the discussions will cover the key issues outlined below, following the 5-step NSPM process described above. Please provide comments on this list of issues and identify any additional issues the Commission should evaluate.**

a. **Discuss and confirm relevant policy goals. See preliminary list above.**

b. **Review and confirm the scope of the BCA framework's application to different regulatory contexts for DERs, as needed, e.g., IOU programs, pricing mechanisms, procurement, rate cases, planning, and grid investments.**

c. **Review the decision-making process for DER investments in terms of: BCA, rate impact analysis, and relevant qualitative and quantitative factors and metrics that may fall outside the BCA and rate impact analyses.**

d. **Review the utility system impacts currently accounted for in BCA for the range of DERs and identify any gaps and methodologies to account for missing impact factors. What methodologies can be used to quantify or account for "hard to quantify" utility system impacts?**

e. **Determine the relevance of accounting for host customer impacts based on articulated policy goals and objectives. Should the host customer impacts currently accounted for in IOUs TRC test be reviewed? Should the primary test include host customer impacts? Is there symmetrical treatment of costs and benefits? What methodologies can be used to quantify or account for "hard-to-quantify" host customer non-energy impacts?**

f. **Discuss how to treat "other" fuels, i.e., fuels that are affected by DER but are not provided by the utility funding the DER in the primary test.**

g. **Determine the relevant societal impacts based on articulated policy goals and objectives. Review the societal impacts currently accounted for in IOUs' TRC test and identify gaps. What methodologies can be used to quantify or account for "hard to quantify" societal impacts?**

h. **Discuss whether and how the primary test can be applied to all DER types**

i. **Discuss whether secondary tests are warranted and, if so, what those tests should be.**

j. **Review the process and considerations for selecting a discount rate for primary and secondary tests.**

PSE does not disagree with any item included on this list. Nor does it have any additional items to propose at this time, other than to note again that stakeholder discussions of methods to measure and quantify the achievement of policy goals will be a critical second step after item (a) in this list. This step will also be necessary regardless of whether the Commission adopts a new jurisdictional-specific benefit-cost analysis framework or modifies existing ones.

PSE also notes that much of the work that will inform the Commission's examination here is also being conducted in other work streams. For example, PSE has been working towards developing a comprehensive list of quantitative metrics to include in the BCA model in the context of its CEIP. This has required considerable resources on a truncated timeline, and this process is still in development. Given this ongoing work, the Commission might also consider allowing utilities to continue to develop accurate and effective sets of cost tests, in consultation with diverse stakeholders, rather than creating a universal test during the pendency of these work streams that might not fit the needs of all utilities. PSE looks forward to participating in this proceeding and is committed to exploring additional opportunities to improve its evaluation framework for new and exciting DER technologies, many of which will be increasingly important as CETA implementation continues.

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PSE appreciates the opportunity to provide these comments. Please contact Brett Rendina at (425) 457-5677 for additional information about these comments. If you have any other questions please, contact me at (425) 456-2142.

Sincerely,

/s/ Jon Piliaris

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