



December 1, 2025

Via electronic filing

Oregon Public Utility Commission
Attn: Filing Center
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Re: Renewable Northwest's Answers to Staff's Questions for Energy Stakeholders

OPUC Docket No. UM 2409: Investigation of Cost Effectiveness Analysis of Grid Enhancing Technologies in Utility Integrated Resource Plans

1. *Expectations: What are your general expectations for how utilities will comply with HB3336 and include transmission alternatives and Grid-Enhancing Technologies (GETs) in Integrated Resource Plans (IRPs)?*

Under HB 3336, when a utility files a “resource or grid investment plan with the Public Utility Commission proposing additions, improvements or modifications to a transmission system,” the utility must “conduct an analysis of alternatives to determine the cost-effectiveness and timetable of multiple strategies, including strategies that use grid enhancing technologies.”¹ Utilities are also required to include “a separate section” within their integrated resource plans (IRP) and clean energy plans (CEP) “that provides a strategic plan for using grid enhancing technologies where doing so is cost-effective.”² From Renewable Northwest's (RNW) perspective, this means that utilities should conduct a robust analysis of transmission alternatives and GETs and present a plan for using cost effective GETs within IRPs, though there are a number of ways that could work in practice. In RNW's view, the law also requires the utilities to analyze whether various non-wires alternatives—including demand-response, flexible assets like energy storage, energy efficiency, and others—are cost-effective and likely to lead to more efficient utilization of the transmission system.

¹ Section 1(3)

² Section 1(4)

a. What level of analysis are you looking for in IRPs?

GETs analysis in an IRP should include a clear and comprehensive evaluation of technologies that increase the capacity, efficiency, reliability or safety of the existing transmission system, including but not limited to the technologies that are explicitly referenced in statute: dynamic line ratings, advanced power flow control, topology optimization, advanced reconductoring, flexible alternating current transmission systems, and energy storage. More specifically, when a utility identifies a problem on the existing transmission system, the utility should conduct an alternatives analysis that considers GETs that can solve that specific problem. Analysis should include both a quantitative and qualitative assessment of the costs and benefits associated with the various alternatives. This analysis should include a comparator to assess the costs that may be avoided by investing in GETs or other transmission alternatives that increase the flexibility of the system. Based on that analysis, the utility should choose the solution that cost effectively addresses the problem and provide a comprehensive explanation of why that solution was chosen and why the alternative options were rejected. For ease of inclusion, this analysis may be included in a table or matrix format, similar to the IRP Portfolio requirements in the new rules promulgated in AR 669.

b. What do you think is currently missing from transmission alternatives analysis in IRPs?

Utilities have separate processes for local transmission planning and resource planning. Local transmission plans identify corrective actions and upgrades to enhance local system reliability. Within IRPs, utilities often list or briefly describe the reliability-driven local transmission upgrades that were identified in an earlier transmission planning process, which sometimes involve GETs. However, neither the IRP nor the transmission planning documents provide a fulsome explanation of how GETs and transmission alternatives were considered and why the specific transmission solution was identified over alternatives. Further, local transmission plans are focused on the reliability benefits of upgrades or potential GETs options and fail to capture the potential cost and public policy benefits of GETs, which means these don't materialize in the IRP either.

It would be helpful if utility IRPs considered a wide range of transmission investments and their potential benefit to the system in addition to the requirement that GETs and transmission investments be considered under HB 3336. In today's transmission-constrained world where diverse resources from geographically distant regions are needed to meet load growth and state policy mandates, it is not enough for IRPs to consider the impact of generating and demand-side resources alone. Robust consideration of various transmission investments, the impacts of constraints, and alternatives—including GETs—must be considered in the IRP process. This can be achieved by accurately representing transmission constraints in IRP models and then taking

steps to quantify the value of transmission expansion opportunities, that include transmission alternatives and GETs. Only by evaluating the impacts of transmission congestion can we see the true value of transmission-related investments in IRPs.

The integration of transmission planning in IRPs has been piecemeal and inconsistent between regulated utilities. Because significant transmission investment is needed throughout the West to ensure reliability, affordability, and meeting state policies, it is essential that transmission investments and alternatives be accurately assessed within utility IRPs. Interwest has authored a report on transmission planning in the IRP context and accurately depicts the need for more fulsome transmission analysis within individual IRPs and the need for a more coordinated approach to transmission planning across the Western Interconnection.³

Regional transmission planning is already occurring on a voluntary basis in the Western Transmission Expansion Coalition (“WestTEC”). The WestTEC effort will create an actionable transmission plan for the Western Interconnection based on 10 and 20 year scenario planning. Since the work to look at needed transmission investment under a wide range of scenarios is already occurring, it will be relatively easier for Oregon-regulated utilities to begin to fold this type of analysis into their existing IRP framework.

c. What’s the minimum amount of information or analysis that should be included?

See response to question 1a and 1b.

2. Challenges: What do you see as the biggest challenges in implementing HB 3336?

There are a number of challenges to implementing HB 3336, from the analysis itself, to the way utilities present the analysis, to the criteria used to review the analysis. The biggest challenge may be figuring out where and when to conduct the transmission alternatives analysis within existing planning processes and whether those separate processes need to be integrated to effectively implement HB 3336.

a. What challenges do you see in including GETs analysis in IRPs?

- Integrating GETs analysis into existing planning processes given that local transmission planning is currently separate from integrated resource planning. As discussed, this proceeding could be used to ensure consistent treatment of transmission planning within IRPs, which will streamline various processes and ensure HB 3336’s intent is met.

³ See generally Evaluating Transmission Opportunities in Integrated Resource Plans, available at <https://interwest.org/wp-content/uploads/2025/09/Transmission-in-IRP-Part-1.pdf>.

- Capturing the full value of GETs and transmission alternatives, especially given the different transmission constraints and challenges that they can address.
- Clearly communicating how the analysis was conducted, which transmission alternatives or GETs were considered, and why the specific solution was selected over alternatives.
- Presenting information in an IRP in a clear, digestible way.

b. What challenges do you see in the Oregon PUC developing a set of review criteria for GETs in IRPs?

- Recognizing that utilities use different modeling platforms that may have different capabilities for modeling GETs.
- Developing review criteria that is broad enough to apply to utilities with different modeling capabilities and transmission systems.
- Ensuring accurate quantification of both the costs of transmission constraints and the benefits of transmission investments, alternatives, and GETs that are consistently applied.
- Accurately quantifying the geographic benefits of GETs and transmission alternatives.

c. What challenges do you see in developing GETs and transmission alternatives' cost-effectiveness criteria as described in HB 3336?

The strategies enumerated in HB 3336(3) that must be assessed from a cost-effectiveness perspective are diverse and require the utility to consider the costs of not making an investment. For example, if an investment in GETs is not made, how would the decreased transmission reliability or capacity impact the system's costs? How would not making the investment increase costs to customers because renewable curtailment will not be reduced? These types of counterfactual analyses, while potentially difficult to assess, will be essential to determine whether an investment in GETs or transmission alternatives is cost-effective. It will be particularly important for utilities to assess how an increased capacity to connect new renewable and nonemitting energy resources under HB 3336(3)(e) will decrease costs in utility RFPs and lead to a more cost-effective pathway to comply with HB 2021. The need to include a wide range of potential costs and impacts in assessing the cost-effectiveness of GETs will be challenging, but it is a necessary undertaking to ensure a least-cost, least-risk plan for customers and align with the legislature's intent in passing HB 3336.

3. Approaches: Do you have suggestions regarding approaches or review criteria that Oregon PUC staff should consider at this point in the docket?

It may be helpful to hear directly from utilities about their local transmission planning and integrated resource planning processes. For example, it would be helpful to understand: what each process is designed to address specifically related to transmission needs, how these plans do

and do not overlap, the cadence and regulatory oversight of these two planning processes, how GETs could be evaluated in the context of both processes, how well their models currently capture the value of GETs, and any work the utility has done to improve their modeling capability of GETs.

To quantify the economic impact of transmission investments, GETs, or transmission alternatives, utilities can compare the total cost of IRP portfolios with and without the investment in place. Utilities routinely run various scenarios in the IRP context. Including scenarios for various transmission-related investments can help show how generation portfolios change with various investments, how total system costs are impacted, and assess the extent to which costs are saved as a result of the investment.⁴

a. When and how should transmission alternatives analysis be conducted?

From RNW's perspective, there are a number of ways to integrate transmission alternatives analysis into current processes, ranging from relatively small changes to incorporate GETs to wholesale changes to planning processes that could capture the true value of GETs. We detail these options as a continuum below and based on the information provided in the November 19, 2025 workshop in this docket. There are likely additional ways to conduct transmission alternatives analyses and we look forward to reviewing the other comments in this docket. We hope to discuss various options with Staff, stakeholders, and utilities to understand the benefits, feasibility, and tradeoffs of different approaches. Including robust consideration of GETs and transmission alternatives in utility IRPs is the most efficient means to implement HB 3336 and would allow for GETs and transmission alternatives to be assessed alongside a suite of other utility investments.

- 1) Utilities conduct local transmission planning much as they do now but incorporate GETs as potential solutions to transmission constraints. Utilities evaluate a range of solutions, their costs and benefits, and fully explain why the selected action was chosen above alternatives. Utilities then bring this analysis forward in an IRP for stakeholder feedback and Commission review, which leads to an acknowledgement decision that later informs prudence determinations in rate cases. The example from transmission planning in CAISO on page 28 of the November workshop slides provides a good starting point for the kind of alternatives analysis that we would like to see.
- 2) Same as above, except utilities use reliability aware production cost modeling with power flow as described in the November 19, 2025 workshop in this docket. According to PNNL and NREL, this modeling approach can more fully capture the benefits of GETs, rather than the current reliability-focused approach. As discussed in these comments, it is essential to capture the intricacies of real-world power flow and reliability when

⁴ Ibid, at 18.

conducting an analysis of transmission buildout and associated alternatives. RNW looks forward to learning more about these concepts and their application in this docket going forward.

- 3) According to PNNL and NREL, the ideal treatment of transmission and GETs in long term planning involves a more comprehensive overhaul of existing practices. This ideal treatment involves a co-optimized transmission and resource planning process whereby the transmission evaluation is iterated along with the resource plan so that transmission (and GETs) can influence resource selection. Again, RNW looks forward to learning more about this co-optimized approach going forward.

b. What elements should be included in the set of GETs cost-effectiveness review criteria?

As discussed in 2b, it is essential to ensure accurate quantification of both the costs of transmission constraints and the benefits of transmission investments, alternatives, and GETs. In addition, utilities should ensure they are accurately quantifying the geographic benefits of GETs and transmission alternatives. As discussed in 3, utilities should include scenarios in IRPs for various transmission-related investments to show how generation portfolios change with various investments, how total system costs are impacted, and the extent to which costs are saved as a result of the investment.⁵ RNW looks forward to reviewing responses from other parties and working iteratively throughout this process to land upon a consistent framework.

c. How/should GETs analysis be integrated with current processes?

See response to 3a.

4. *Outcomes: Given that there may be many ways to accomplish good outcomes, what would successful HB 3336 implementation look like to you and the community/group you represent? What would it enable? What would it inform?*

Successful implementation starts with a good process where interested parties can share various approaches to analyzing transmission alternatives and GETs in IRPs, discuss the tradeoffs of each, and hopefully align on an approach that addresses the concerns of all parties. For RNW, successful implementation would mean that utilities are consistently and fairly evaluating GETs and clearly communicating the results of the transmission alternatives analysis in IRPs. This would allow stakeholders, staff, and the Commission to more fully vet utility actions related to the transmission system and support utilities in moving projects forward that can provide a host of benefits at lower cost than traditional grid upgrades. RNW also recommends that this process dovetail with the Commission's consideration of performance-based regulation in AR 676 to

⁵ Ibid, at 18.

ensure that there are adequate incentives in place for utilities that achieve GETs-related outcomes identified in this docket, given that many GETs solutions are not adequately incentivized by the existing regulatory construct.

Respectfully submitted this 1st day of December, 2025,

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