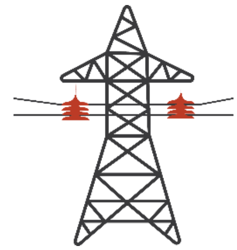
OREGON DEPARTMENT OF ENERGY 50 YEARS of SERVICE

Oregon Energy Strategy Key Model Findings

Developing Clean Electricity Generation and Transmission Policy Working Group



The Developing Clean Electricity Generation and Transmission Policy Working Group is one of five Policy Working Groups formed to reflect on the results of the Oregon Energy Strategy technical modeling and help identify policy gaps and opportunities. This group will focus on electricity generation and storage in front of the meter, transmission, and associated development needs, barriers, and competing priorities.

Model results provide valuable information on the tradeoffs of different energy choices. This document provides a summary of the modeling results relevant to this working group. It is meant to assist members in processing the results so they can engage in productive policy discussions.

A few of the most fundamental modeling findings for this working group are:

- The model shows significant near-term load growth.
- Both in-state and out-of-state resources contribute to a least-cost supply portfolio.
- Oregon does not have sufficient physical transmission capacity to meet the modeled electricity flows.
- The model consistently builds more generating capacity.
- Decarbonizing Oregon's electricity may require more policy action.

Background: Oregon Energy Strategy Energy Pathways Modeling

Using input from Tribes, the Oregon Energy Strategy's Advisory and Working Groups, staff-to-staff conversations with state agencies and participation in an Inter-Agency Steering Group, and comments from the public, ODOE and its technical contractor developed scenarios that represent different energy pathways the state could take to achieve its energy policy objectives by 2050. The model uses a two-step process:

1) It develops a bottom-up demand model to establish baseline and future energy demand in Oregon's economy from now to 2050.
2) It determines the energy supply that can meet that demand reliably and at least cost.

The model compares energy pathways from a Reference Scenario to six Alternative Scenarios. The Reference Scenario includes "aggressive but achievable" adoption of demand-side technologies and actions, including energy efficiency and electrification. Assumptions were informed by multiple studies that assessed technology options and strategies to decarbonize the energy sector.[i] The model then selected the least cost portfolio of supply-side solutions to meet this demand over time. The Alternative Scenarios each change something critical from the Reference Scenario and seek a least-cost pathway across available resources given the new constraint.

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[i] ODOE references some studies in the 2022 Biennial Energy Report: *Charting a Course for Oregon's Energy Future*.

For more information on how the model works and the key assumptions for the Reference and Alternative Scenarios, see the Energy Strategy Modeling Assumptions and Sources document. Key assumptions refer to specific demand-side inputs or supply-side constraints that were defined as inputs to the model. It is recommended that members of the Developing Clean Electricity Generation and Transmission Policy Working Group review the Reference Scenario assumptions around Tech Load Growth, Electricity Generation Technologies, Land Use and Natural Resources, and Transmission and Distribution, and key assumptions for the 50% Lower Tech Load Growth in Reference Scenario sensitivity, Limited Utility-Scale Electricity Generation in Oregon, High Distributed Energy Resources + Limited Transmission, and Alternative Flexible Resources.

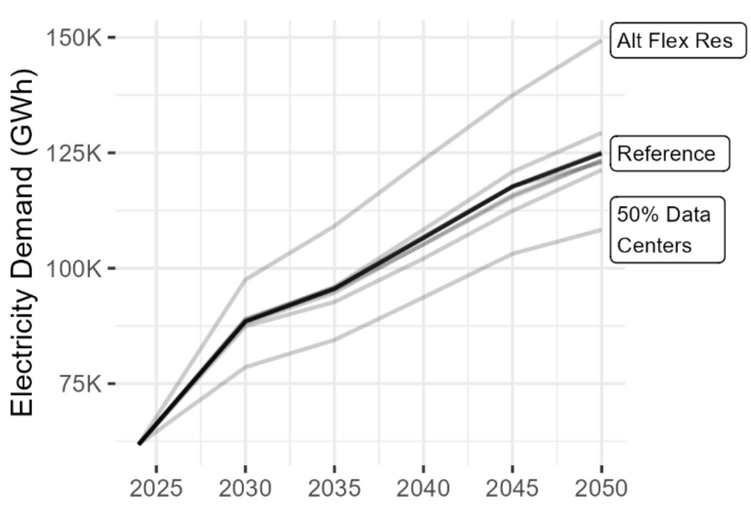
High-level key takeaways relevant for all policy working groups include:

- Oregon has multiple pathways to achieve our energy policy objectives.
- All scenarios indicate a need for additional clean electricity infrastructure.
- Existing energy transition policies get us far.
- More action is needed than current policies will deliver.

As you review the key findings below, ask yourself: What policies does the State of Oregon need to maintain or adopt to support additional clean electricity? What topics need to be better understood before policy choices can be made about clean electricity options?

Key Finding 1: The Model Shows Significant Near-Term Load Growth

Figure 1: Electricity Demand in Oregon Across All 10 Scenarios and Sensitivities (2024-2050)



Notes: Reference Scenario is shown in bold. All 10 scenarios and sensitivities are shown but may not be distinguishable due to overlap. Scenarios/sensitivities with the highest and lowest growth are labeled.

The demand on Oregon's electricity system increases across all modeled scenarios. Figure 1 shows total electricity demand over five-year increments from 2024 to 2050 for each modeled scenario.

In the Reference Scenario, the modeling indicates that by 2030, Oregon's electricity demand could increase approximately 40 percent, from about 60,000 gigawatt-hours of electricity today to over 85,000 GWh. By 2035, Oregon's electricity demand could reach over 95,000 GWh.

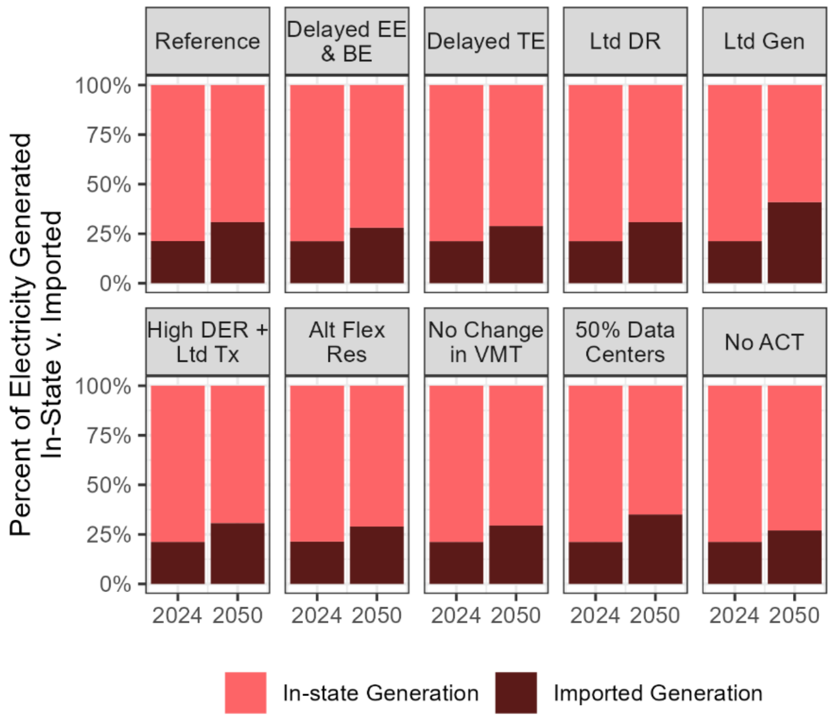
The biggest near-term driver of new demand is new tech loads, including data centers. This load growth is uncertain. Yet even if only half the modeled tech load shows up by 2030, Oregon's electricity demand could still increase over 25 percent by 2030, reaching over 75,000 GWh. By 2035, Oregon's electricity demand could reach over 80,000 GWh, roughly a 35 percent increase from 2024 even with only half the modeled tech load.

This near-term load growth presents a challenge to Oregon electric utilities, who must plan for and secure sufficient resources to maintain reliability.

Key Finding 2: Both In-State and Out-of-State Resources Contribute to a Least-Cost Supply Portfolio

The model indicates that Oregon's growing electricity demand will likely be met with resources both in Oregon and in other western states. In all scenarios, the model selected a least-cost supply mix that includes generation from both in-state and out-of-state resources. Figure 2 illustrates how both in-state generation (in light red, the top color block) and imported electricity (in dark red, the lower color block) contribute to the state's electricity mix across all scenarios and sensitivities.

Figure 2: In-State Generation and Imported Electricity (2024 & 2050)



Notes: In-state generation includes both generation consumed in-state and generation exported to other states.

To meet higher demand, utilities will need to obtain more electricity. In the Reference Scenario, in-state generation increases from approximately 49,000 GWh in 2024 to approximately 51,000 GWh in 2030 (about 6 percent) and to approximately 60,000 GWh by 2035, or more than 20 percent compared to 2024. Imported generation increased from around 13,000 GWh in 2024 to around 37,000 GWh in 2030 (about 180 percent) then decreased slightly to approximately 35,000 GWh by 2035. These results indicate a need for some in-state development of resources.

Access to fewer in-state electricity generation resources results in more electricity imports and higher modeled costs. Alternative Scenario #4 (Ltd Gen) tested the question: *what if only half as much wind, utility-scale solar, and geothermal selected in the Reference Scenario was built in Oregon*? In this scenario, imported generation increased nearly threefold by 2030, from approximately 13,000 GWh to nearly 38,000 GWh. Further, the cumulative net present value of costs from 2024-2050 increased by about $7 billion relative to the Reference Scenario.

There are different effects associated with developing in-state vs. out-of-state resources that the modeling does not fully capture. For example, local development can promote economic development but also affects local natural resources. Similarly, local development can enhance grid resilience and grid reliability, while access to out-of-state generation can provide reliability and cost benefits from having a geographically diverse supply portfolio.

Key Finding 3: Oregon Does Not Have Sufficient Physical Transmission Capacity to Meet the Modeled Electricity Flows

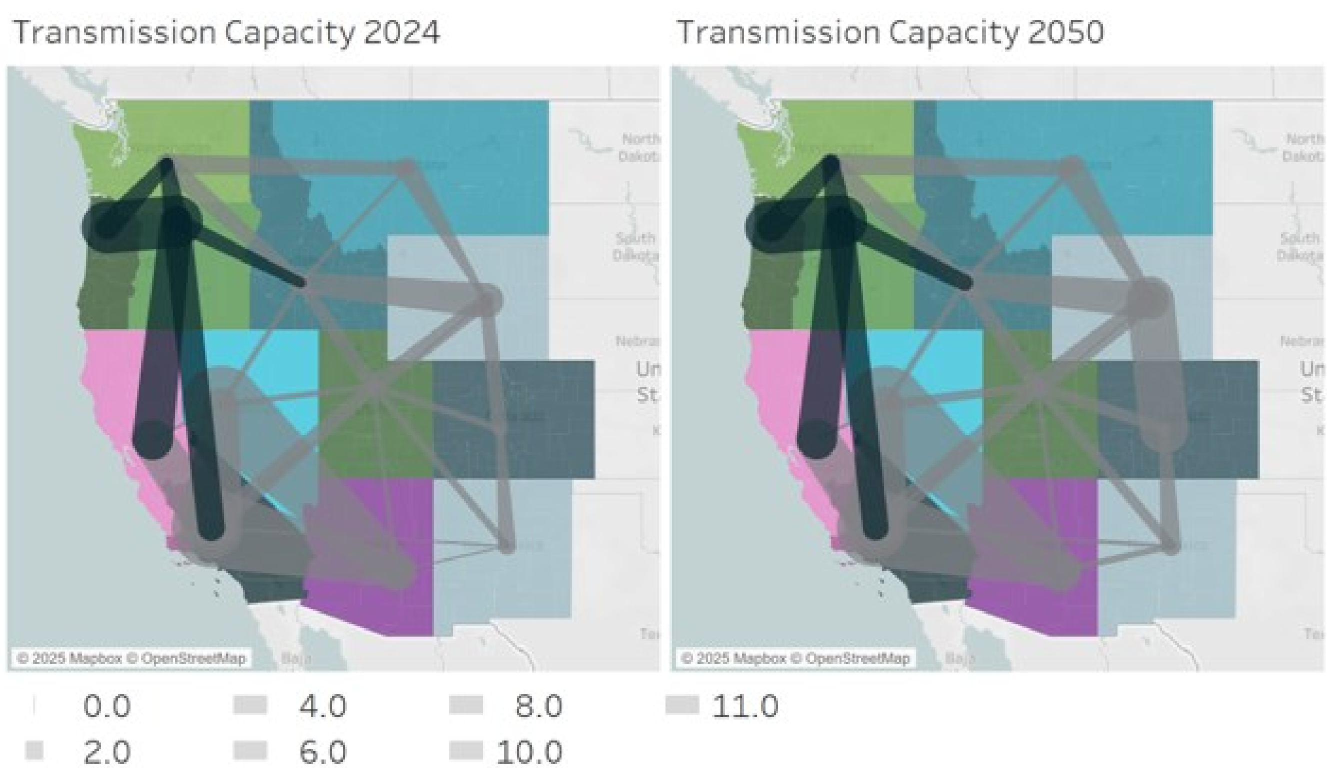
The modeling results for all scenarios indicate the need for additional transmission to meet state energy goals. Before diving into more detail, it is important to understand the way the modeling approaches transmission.

The model includes a pipeflow representation of physical transmission capacity between the modeled zones (Washington, Oregon West, Oregon East, Idaho, California North, etc.). The maps in Figure 3 below illustrate the model's pipeflow representation in 2024 and 2050. The model expands transmission only if there is not adequate physical transmission capacity to accommodate the flows required to meet load in each simulated hour. The model does not represent transmission rights, who holds them, or the extent to which transmission rights are available without additional transmission expansion.

Additionally, the model considers the western United States as a single balancing area (rather than 34 separate ones[ii]) with a single, centralized system operator.

The model faces zero commercial congestion and can make perfectly efficient use of the transmission system — more efficient use than could be achieved under real-world conditions today or in the foreseeable future.

Figure 3: Inter-Zonal Transmission Capacity (GW) (2024 & 2050)



[ii] For additional background, please see U.S. Energy Information Administration, U.S. electric system is made up of interconnections and balancing authorities (July 20, 2016), https://www.eia.gov/todayinenergy/detail.php?id=27152.

In every modeled scenario, the model expands Oregon's inter-zonal transmission capacity. The incremental expansion is indicated in Table 1 below. These results indicate a consistent need for additional physical transmission capacity. In the Reference Scenario, the model increases Oregon's inter-zonal transmission capacity by 1.3 GW by 2050. Transmission capacity increases more in some alternative scenarios: by 1.9 GW in Alternative Scenario #3 (Ltd DR), by 2.1 GW in Alternative Scenario #4 (Ltd Gen), and by 6.4 GW in Alternative Scenario #6 (Alt Flex Res).

Table 1: Incremental Transmission Expansion by 2050 (GW)

Scenario	Oregon East – Oregon West	Oregon to Other States	Total
0. Reference	0.1	1.2	1.3
1. Delayed EE & BE	0.1	0.8	0.9
2. Delayed TE	0.1	0.9	1.0
3. Ltd DR	0.8	1.1	1.9
4. Ltd Gen	0.6	1.5	2.1
5. High DER + Ltd Tx	0.1	0.6	0.7
6. Alt Flex Res	4.0	2.4	6.4

Not included in the above totals is transmission within each zone because intra-zonal transmission is not directly modeled. Instead, when the model selects an in-state generating resource as a cost-effective solution to meet electricity demand, that least-cost selection includes a proxy cost adder for additional in-state transmission.

These model results indicate a need for development of both intra-state and inter-state transmission.

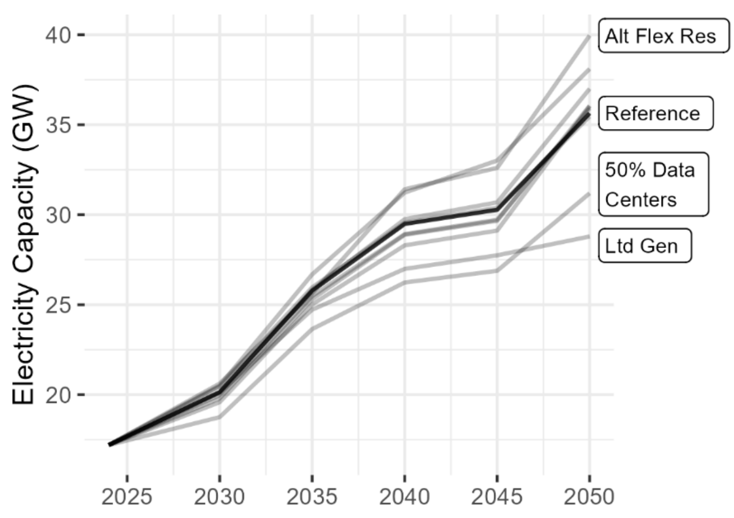
Key Finding 4: The Model Consistently Builds More Generating Capacity

Across all scenarios, the modeled least-cost supply portfolio includes a substantial increase in installed capacity in Oregon in every five-year increment, including 2030. Figure 4 shows how total nameplate capacity increases from 2024 to 2050 across all scenarios.

The model chooses a least-cost supply portfolio based on available existing resources and potential new resources. When the model selects a new resource, that new resource is assumed to be operational in the year selected, meaning development must have begun some time beforehand.

These results indicate a need for near-term action to develop new generating capacity.

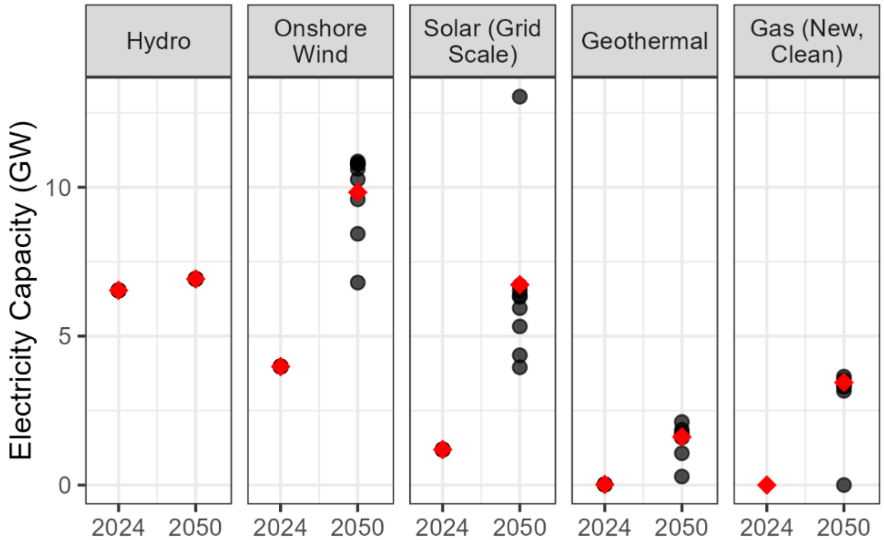
Figure 4: Electricity Capacity in Oregon Across All 10 Scenarios and Sensitivities (2024-2050)



Notes: Reference scenario is shown in bold. All 10 scenarios and sensitivities are shown but may not be distinguishable due to overlap. Scenarios/sensitivities with the highest and lowest growth are labeled.

The types of capacity selected varies somewhat across scenarios. Figure 5 shows the change in generating capacity from 2024 to 2050 for five of the generating technologies. Each dot indicates the total capacity in Oregon for that technology in a scenario; the red diamonds indicate the capacity in the Reference Scenario. Figure 5 shows that, across the modeled scenarios, hydropower remains a foundational resource for Oregon, and it shows significant increases in capacity of Oregon's onshore wind, grid-scale solar, enhanced geothermal, and new clean gas plants (100 percent hydrogen or biogas). Capacity additions may reflect new facilities or upgraded existing facilities.

Figure 5: Electricity Capacity in Oregon for Select Technologies (2024 & 2050)



Notes: Red diamonds indicate electricity capacity in Oregon for the Reference scenario. Each black dot indicates electricity capacity in Oregon in an Alternative scenario/sensitivity.

While it is not certain exactly what resources will be available and most cost-competitive to meet Oregon's electricity demand over the coming years, the modeling suggests there is a need for new generating capacity in Oregon. A diverse supply mix will likely include significant amounts of hydropower, wind, and solar. Enhanced geothermal and clean gas facilities are not expected to be available near-term, but they could play a role in the future supply mix.

Key Finding 5: Decarbonizing Oregon's Electricity May Require More Policy Action

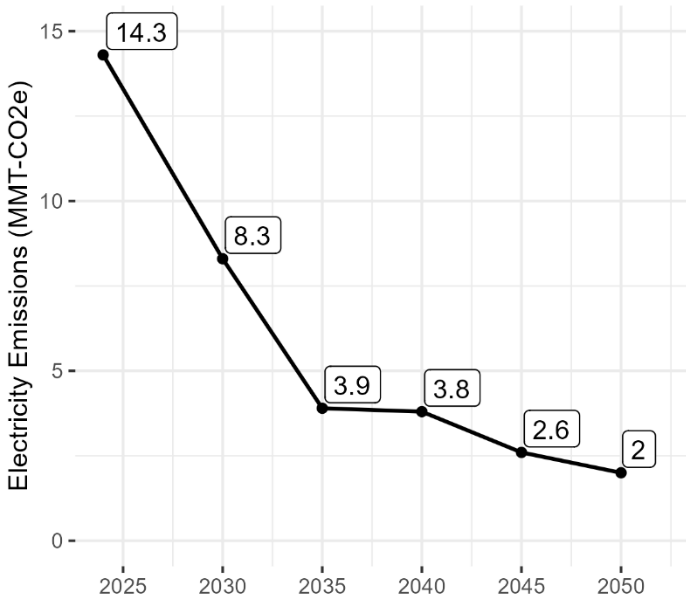
One of the core policies directly included in the modeling is the clean energy targets in HB 2021 (2021). HB 2021 requires PacifiCorp, Portland General Electric, and electricity service suppliers in Oregon to reduce emissions 80 percent below the applicable baseline by 2030, 90 percent by 2035, and 100 percent by 2040. PacifiCorp and Portland General Electric Company's baseline is set as an average of their emissions in 2010-2012; the baseline for electricity service suppliers is set as an emissions intensity of 0.428 million metric tonnes of carbon-dioxide equivalent per megawatt-hour.

The model included these targets in two ways. First, because the model is not utility-specific, the model applied HB 2021's clean energy targets to a percentage of statewide load: 62.1 percent, the amount served by the covered entities in 2023.[iii] Second, in 2030, the model imposed a statewide cap on electricity emissions of 9.767 MMT-CO2e. This cap roughly approximates how high statewide emissions could potentially be, considering the possibility that new tech loads in non-HB 2021 jurisdictional service

[iii] Oregon Public Utility Commission, 2023 Oregon Utility Statistics Book, available at https://www.oregon.gov/puc/forms/Forms%20and%20Reports/2023-Oregon-Utility-Statistics-Book.pdf

territories might be served with emitting power sources.[iv] The cap assumes service through unspecified imports at the current assigned emissions factor of 0.428 MT-CO2e/MWh. In the sensitivity that explored 50 percent lower tech loads, the cap was approximated at 7.567 MMT-CO2e, reflecting a lower potential for emissions to rise with less overall load growth.

Figure 6: Modeled Oregon Electricity Emissions



Modeling the clean electricity targets set in HB 2021 drove significant emissions reductions across all scenarios. The economy-wide decarbonization targets in Executive Order 20-04 drove further emissions reductions beyond what HB 2021 is likely to require. Figure 6 shows the modeled reduction in emissions from the electricity sector over five-year increments. Modeled emissions decrease from 14.3 MMT-CO2e in 2024 to 8.3 MMT-CO2e in 2030, 3.9 MMT-CO2e in 2035, 3.8 MMT-CO2e in 2040, 2.6 MMT-CO2e in 2045, and finally 2.0 MMT-CO2e in 2050. In 2050, the remaining electricity sector emissions can predominantly be attributed to unspecified imports and existing gas facilities that the model continues to operate after 2030 for reliability purposes, reflecting likely demand for the power and flexibility they could provide in the absence of policy-driven alternatives.

The modeled emissions are uncertain. On the one hand, actual emissions may be higher than modeled. For example, the model did not include HB 2021's cost cap or reliability cap. On the other hand, the model does not include any constraint to reflect voluntary emissions reductions goals, which may drive significant emissions reductions. In addition, renewable and non-emitting electricity resources are increasingly cost-competitive, and market economics could provide significant emission reductions. It is ultimately uncertain whether the emissions reductions will occur as modeled absent further policy direction and support.

[iv] Many non-HB 2021 entities have very low emissions currently, as they receive much, if not all, of their power from the Bonneville Power Administration. However, federal law prohibits BPA from serving certain new large loads, which could potentially include many new tech load facilities.