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THE CRIPPLING COSTS OF ELECTRIFICATION AND NET ZERO ENERGY POLICIES IN THE PACIFIC NORTHWEST

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REASONABLE ENERGY

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EXECUTIVE SUMMARY

Oregon and Washington State have committed to electrification policies to eliminate energy-related greenhouse gas emissions. Both states have adopted California's Advanced Clean Car rules, which require 100% of all new cars and light trucks sold to be electric by 2035. Oregon law HB 2021 requires the state's electric utilities to eliminate all fossil-fuel generation and supply 100% zero-emissions electricity by 2040. Washington State's Clean Energy Transformation Act requires the same by 2045. That zero-emissions requirement applies as well to electricity imports. Both states intend to reach zero energy-related greenhouse gas emissions by 2050, including replacing all fossil-fuel space- and water-heating systems with electric heat pumps. These electrification efforts will likely double existing electricity demand and require major investments in new generating capacity.

The sole coal-fired power plant in the two states, located in Washington, will be retired next year. Both states envision replacing existing fossil fuel generation and meeting the projected increase in electricity demand with thousands of megawatts (MW) of wind turbines and solar photovoltaics, which will be located in the eastern (and rural) portions of the two states and delivered to the population centers west of the Cascades by building new transmission lines.

But the inherent intermittency of wind and solar power, together with peak electric demands taking place in the early evening hours when there is no solar generation available (and often no wind), means the two states will require large amounts of storage capacity, in addition to the existing hydroelectric storage dams that have been built on the Columbia River and its tributaries. Because no new hydroelectric dams will be built — some environmentalists are seeking to remove the four Lower Snake River dams — the additional storage capacity required will need to come from large-scale battery storage facilities and perhaps a few new pumped hydroelectric storage facilities, whose siting remains controversial.

Using hourly electricity demand in 2023 as a template, coupled with estimates of future load growth arising from electric vehicles and electric space and water heating, we estimate the total additional costs of meeting the two states' electrification and zero-emissions goals. We also consider a more optimistic low-cost renewables scenario in which wind, solar, and storage capital costs decrease by 50% in real (inflation-adjusted) terms by 2050. Finally, we consider an alternative scenario in which the electricity goal is achieved with new nuclear plants and additional natural gas generators. For all three scenarios, we assume the needed generation and transmission capacity will be built by private investors, whether the two states' investor-owned electric utilities or private entities because the states' publicly owned utilities haven't built any such facilities in decades.

The cost difference between the two renewables and nuclear/natural gas scenarios is substantial (**Table EX-1**). Specifically, we estimate the additional costs for the renewables scenario will total about $550 billion in 2024 dollars and about $420 billion under the "low cost" renewables scenario. By contrast, the estimated cost of the nuclear and natural gas scenario totals just under $86 billion. Moreover, these costs exclude the additional investment that will be needed to upgrade local distribution systems to handle the higher peak electric demands from electric vehicle charges and heat pumps.

Table EX-1: Total Costs for Each Scenario through 2050 (Millions of 2024$)

Scenario	Capital Costs[A]	Fixed O&M Costs	Variable Costs[B]	Taxes	Utility Profits	Total Costs
Renewables Only	$232,791	$73,229	($11,381)	$48,363	$206,909	**$549,910**
Lower-Cost Renewables	$170,488	$73,229	($11,381)	$35,267	$150,884	**$418,488**
Natural Gas and Nuclear	$17,953	$7,282	$3,226	$10.889	$46,587	**$85,937**

Notes:

A – includes generation and transmission costs.

B – includes fuel costs (savings).

The effects on customer's electric bills will be devastating. Accounting only for the additional electricity required for EV charging and assuming a modest inflation rate of just 2.0% annually, a typical residential customer's bill will increase by **450%**, from about $110 per month today to over **$700 per month** in 2050. Although customers who currently use natural gas for space heat and hot water will no longer spend money on natural gas, the savings will be dwarfed by the higher cost of electricity. As for commercial customers, they will see their monthly bills increase from an average of about $600 per month today to around **$3,800 per month** in 2050.

The two states' combined energy-related greenhouse gas (GHG) emissions totaled about 150 million metric tons in 2019, the most recent year for which data for both states are available. Assuming these emissions were reduced at a constant rate until they were eliminated entirely by 2050, the reduction in GHGs would total about 1.8 billion metric tons. By comparison, in 2023, world carbon emissions were estimated to be just over 35 billion metric tons. Thus, even if the 100% electrification effort succeeded in eliminating *all* energy-related GHG emissions in the two states, the ***total*** reduction in GHGs between 2024 and 2050 would amount to only ***three weeks*** of 2023 world emissions. If both states eliminated all energy-related GHG emissions by 2040, the resulting decrease in world temperature would be 0.003 ^{o}C. By comparison, the best outside thermometers have an accuracy of about +/– 0.5 ^{o}C, about 170 times larger.

Thus, Oregon and Washington residents will pay hundreds of billions of dollars to achieve emissions reductions without measurable impacts on world climate. By contrast, the impacts on the economic well-being of those individuals and businesses would be only too real. Soaring electricity costs will cripple the two states' economies, causing the loss of thousands of jobs. Energy-intensive industries will likely flee, just as they have left European countries and California because of electricity costs that render them uncompetitive. Consumers will pay more for virtually everything because higher-cost electricity will raise production costs for agriculture and businesses. Recharging the millions of electric vehicles the two states have mandated — 100% of all new light-duty car and truck sales by 2035 — will become prohibitively expensive, limiting mobility.

The results of this study demonstrate that the two states' efforts to achieve a zero-emissions energy future by electrifying their economies and relying almost entirely on additional wind and solar power to supply the electricity needed will impose huge costs on individuals and businesses. Prices for virtually all goods and services will increase. Jobs will be lost as businesses relocate to other states with lower-cost energy. Energy poverty rates will soar. At the same time, the emissions reductions will be so minuscule that the efforts will provide no measurable climate benefits. The two states would be best served by abandoning these goals, focusing instead on providing reliable and far less costly electricity from new natural gas and nuclear plants.

INTRODUCTION

Physical and economic realities appear to be of little concern to policymakers in the Pacific Northwest who, like their California counterparts, relentlessly pursue their dreams of a zero-emissions future. Both Oregon[1] and Washington State[2] have adopted California's Advanced Clean Car rules, which require 100% of all new cars and light trucks sold to be electric. In addition, by 2035, half of all medium- and heavy-duty vehicles sold in those states must be electric, and the sale of diesel trucks will be banned beginning in 2036. Oregon has enacted legislation requiring its electric utilities to be emissions-free by 2040,[3] while Washington State gives utilities until 2045 to achieve that same zero-emissions requirement.[4] By 2050, both states intend to meet virtually all energy needs with zero-emissions resources.

The two states' electrification efforts aren't limited to vehicles. Oregon, for example, has enacted legislation requiring 500,000 heat pumps to be installed in homes and businesses by 2030.[5] Washington changed its building code to make installing anything but electric space and water heating systems more difficult.[6]

Meanwhile, artificial intelligence (AI) and data centers are further increasing electricity demand. The 2024 Pacific Northwest Utilities Conference Committee (PNUCC), for example, raised its forecast summer peak load in 2032 by about 5,000 megawatts (MW), almost 15% greater than the previous year's forecast, and about 7,000 MW higher than the 2022 load forecast. Similarly, PNUCC raised its 2032 winter peak forecast (which is higher than the summer peak) by about 4,000 MW (11%), and by about 8,000 MW (22%) over its 2022 forecast.[7]

Meeting this data center load growth alone will challenge the two states' electric utilities.[8] However, if the two states' zero-emissions laws and 100% electrification mandates are realized, by 2050 the additional generation requirements will dwarf those challenges: electricity demand will be far higher.

The increased loads are supposed to be met by installing thousands of megawatts (MW) of wind turbines and solar photovoltaics in the eastern portions of the two states, which will be delivered to the population centers west of the Cascades with new transmission lines. But the inherent intermittency of wind and solar power, together with the impacts of EV charging and electric heat on peak demand in the early

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1 Oregon Adopted Rule, DEQ-23-2022.

2 Washington State, Clean Vehicles Program, Chapter 173-423 WAC.

3 Oregon HB 2021, 2021.

4 Washington State Clean Energy Transformation Act, SB 5116, 2019.

5 Oregon HB 3409.

6 Melissa Santos, "New Washington state rules promoting heat pumps face pushback," Axios, December 4, 2023.

7 PNUCC, 2024 Northwest Regional Forecast, May 2024.

8 Lynda Mapes, Seattle Times, "Surge in electricity spells trouble for PNW forecasts show," April 11, 2024.

evening hours when there is no solar generation available (and often no wind), means the two states will require large amounts of storage capacity in addition to the existing hydroelectric storage dams that have been built on the Columbia River and its tributaries. Hence, unless other large-scale storage technologies are discovered, developed, and commercialized, the additional capacity will come from large-scale battery storage and perhaps a few pumped-hydroelectric storage facilities.

This report evaluates the costs of meeting the legislated 100% zero-emissions requirements for electricity and the 2050 goals of eliminating fossil-fuel energy use for space and water heating. Because we assume the needed energy will be supplied with electricity,[9] we focus on the costs to add the necessary generation and the additional transmission infrastructure. Electric ratepayers will bear those costs. As shown, the soaring costs will not only end the two states' status as having some of the nation's lowest electric rates, they will impose economic hardships on individuals and businesses. The analysis presented in this report assumes that EV owners are allowed to charge their vehicles when it is most convenient for them, just as owners of gasoline-powered vehicles can refill their vehicles at their convenience.

Of course, the costs of accommodating EV charging and converting existing fossil-fuel space and water heat to electricity can be reduced by "managing" charging loads, a euphemism for rationing access. Costs can also be lowered by reducing the reliability of the electric system, in other words, making blackouts more likely to occur because there is insufficient generating and transmission capacity to meet increased electricity demand. However, both alternatives belie claims that electrification provides unalloyed consumer benefits. Thus, for purposes of this report, we assume that electricity demand will not be managed, and existing reliability standards will be maintained. We assume that consumers can access electricity when they want and that utilities will make the necessary investments to meet demand as reliably as today.

ESTIMATING ELECTRICITY DEMAND BY 2050

The two states' planned elimination of fossil fuel generation will exacerbate the need for new generating capacity. Oregon has no operating coal-fired power plants. The one plant in Washington State, the Centralia Big Hanaford plant in Lewis County, will cease operation next year under an agreement signed by Governor Christine Gregoire in 2011.[10]

In the larger Pacific Northwest region, which includes Idaho and Western Montana, coal-fired generating capacity totals about 2,800 megawatts (MW) from three plants: Colstrip Units 3 and 4, located in Montana; Jim Bridger Units 3 and 4,[11] located in Wyoming; and Valmy Unit 2, located in northern Nevada.

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9 We do not consider generators that run on "green" hydrogen because no such generators exist today and because manufacturing hydrogen of any type requires more energy than the hydrogen can provide. Nor do we consider even more exotic forms of electricity, such as from fusion power.

10 Governor Gregoire signed SB 5769, the "TransAlta Energy Transition Bill." Under the legislation, Centralia Unit 1 was closed in 2020.

11 The Jim Bridger Units 1 and 2 in Wyoming were previously converted to burn natural gas.

Washington State's Clean Energy Transformation Act (CETA) requires the state's electric utilities to eliminate coal-fired generation from retail rates by the end of next year.[12] Although there are no coal plants in Oregon, Oregon law requires the State Treasurer to divest all investments in coal from the state's pension funds.[13]

Although current plans call for some existing coal-fired generators in Montana and Wyoming owned by the state's electric utilities to be converted to natural gas, getting to a zero-emissions future by 2050 means completely eliminating natural gas generation, including all imports.[14] Moreover, the U.S. Environmental Protection Agency's (EPA) newest clean power standards,[15] which require 90% carbon capture for all coal plants and natural gas-fired plants that are expected to operate beyond 2039, are designed to force the closure of all coal plants and make building new natural gas plants economically infeasible.[16]

As discussed above, electricity demand in the Pacific Northwest is forecast to grow rapidly over the next ten years, partly due to the development of electronic data centers and increased usage of so-called artificial intelligence applications. For example, a report prepared by Cushman & Wakefield ranks Oregon's data center market as the fifth largest in the country.[17] The PNUCC ten-year forecast for 2033/34 assumes some additional adoption of EVs and electrification of residential space and water heating (although the degree is not specified in the forecast), but most of the impacts will occur afterward when the two states' 100% EV mandates take effect in 2035 and as electrification of space and water heat increases.

Estimating Additional Electricity Demand Associated with an All-EV Future

The impacts on electricity demand from an all-EV future in Oregon and Washington depend on (i) when owners charge their EVs; and (ii) how much electricity those EVs require as they are charged.

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12 SB 5116, 2019.

13 Alex Baumhardt, "Legislature passes bill to rid Oregon's Public Employee Retirement System of coal investments," Oregon Capital Chronicle, March 5, 2024.

14 Proponents of "green" hydrogen assume that generating plants that burn hydrogen, often called "dispatchable emissions-free resources" (DEFRs), will be available. However, no such generators even exist today. In addition, proponents of "biogas" (e.g., natural gas captured from farm operations) will substitute for traditional sources of natural gas. However, biogas supplies are constrained and, although it emits less carbon dioxide, is not "emissions-free."

15 U.S. EPA, "Biden-Harris Administration Finalizes Suite of Standards to Reduce Pollution from Fossil Fuel-Fired Power Plants," April 25, 2024.

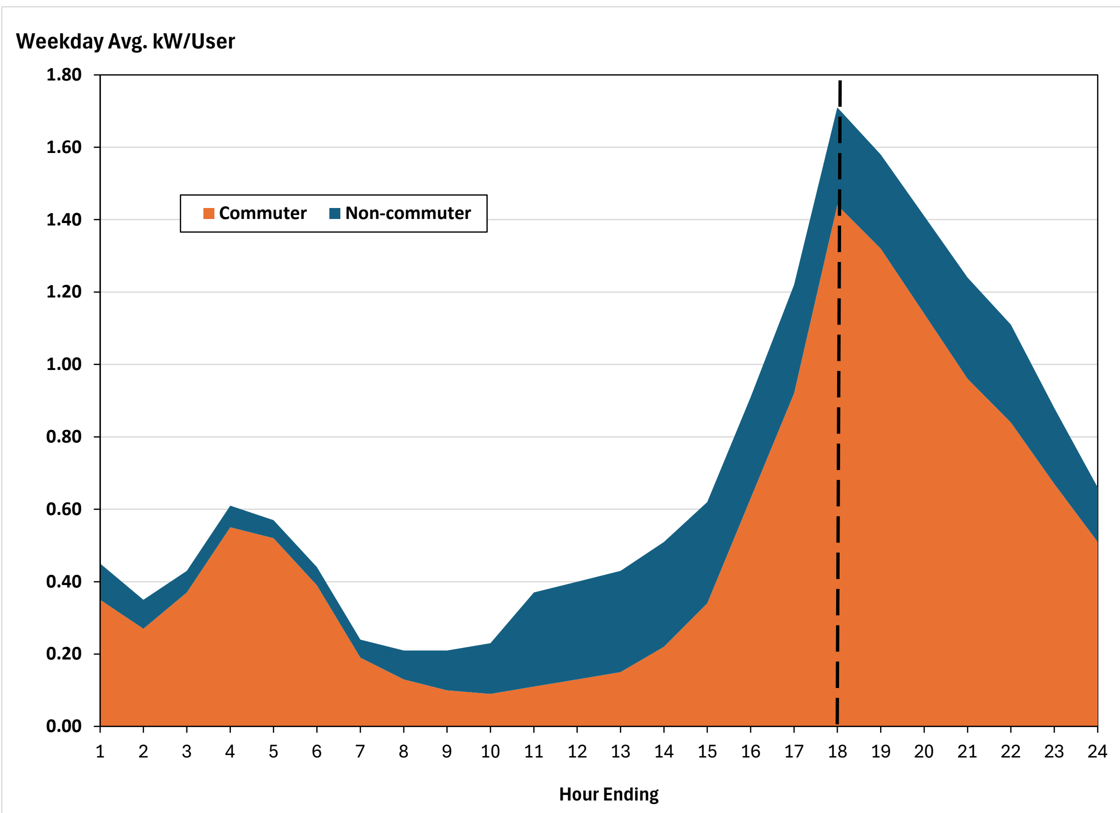
16 The EPA rules are currently being challenged. Ethan Howard, "EEI joins AEP, Duke, other utilities in suing EPA over power plant greenhouse gas rule," *Utility Dive*, May 23, 2024. In addition, a coalition of 27 states has sued EPA over the proposed rules. Clark Mindock, "US Republican attorneys general sue to stop EPA's carbon rule," Reuters, May 9, 2024.

17 Cushman & Wakefield, "Global Data Center Market Comparison," 2024.

Though few studies have examined actual EV charging behavior, Avista Corporation, whose electric utility subsidiary serves much of eastern Washington State and northern Idaho, examined the charging behavior for 439 EV charging ports between 2016 and 2019.[18] Of those, 226 were single-family homes, 20 were multi-family dwellings, 123 were commercial workplaces, 24 were fleet sites, and 7 were fast-charging sites using "Level 3" chargers that operate at high voltage levels.

In addition, the study evaluated the charging behavior of residential EV owners with long-range EVs, which the report defined as EVs with batteries that can provide over 200 miles of range on a single charge. In the five years since the Avista report was published, the battery capacity of new EVs has increased, with most now meeting the "long-range" definition used by Avista.[19] The load profile for these long-range EVs is shown below (**Figure 1**).[20]

Figure 1: Individual EV Load Profiles, Commuters and Non-Commuters (kW)



Source: Avista 2019.

18 Avista Corporation, "Electric Vehicle Supply Equipment Pilot Final Report," October 18, 2019 (Avista 2019).

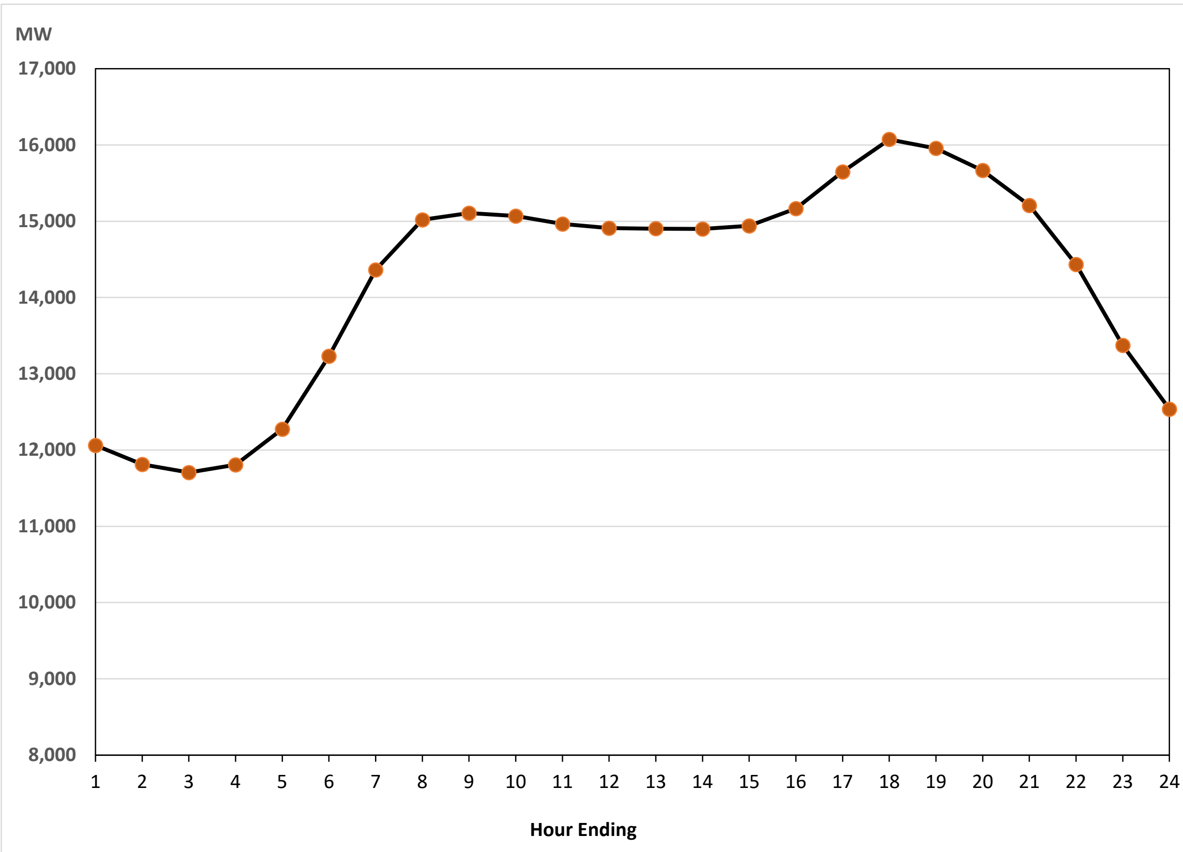
19 Greg Fink, "Longest-Range Electric Cars We've Ever Tested," *Car and Driver*, March 5, 2024.

20 Because most of the long-range EVs were owned by residential commuters, Avista did not determine the load profile for non-commuters who own long-distance EVs. Thus, Figure 1 combines the long-range EV profile for commuters with Avista's load profile for non-long-distance EVs used by non-commuters.

The area of each shaded area equals the average daily electricity consumption. For long-range commuters, the daily electricity consumption averaged 12.3 kWh, while for non-commuters, daily consumption averaged 4.5 kWh.[21]

As shown, combining the commuters and non-commuters, electric demand peaks between 5 and 6 P.M. (Hour ending 18). (We assume that the charging pattern for all EV drivers in both states will be the same as for drivers in the Avista pilot.) Electricity demand typically peaks in the two states at this same hour or the next, between 6 and 7 PM (hour 19), as shown below (**Figure 2**).[22]

Figure 2: Average Hourly Electric Demand in 2023, Oregon and Washington State



Source: U.S. Energy Information Administration, Balancing Authority Data.

Of course, not all EV owners recharge their vehicles daily. Charging frequency depends on how many miles a vehicle is driven on a typical day and the range provided by the vehicle's batteries. Avista found that the average long-range vehicle owner recharged his vehicle 5.6 times per week, while other EV owners

21 Avista 2019, pp. 56, 59.

22 The data shown represent the average of load in that hour on all days of the year. Clearly, on any given day, demand will not necessarily peak in that hour, just as on a given day, EV charging load may not peak.

charged their EVs an average of 4.9 times per week.[23] To be conservative, we assume drivers recharge their vehicles on average 4.9 times per week.

Using the Avista charging load profile data shown in Figure 1, the next step is to estimate total charging electricity peak demand and consumption with a 100% EV future. First, we determine the incremental increase in electricity demand and consumption based on the current number of EVs registered in each state and the total number of registered light-duty vehicles (cars and light trucks). The difference represents the assumed number of EVs that will increase electricity consumption and demand. For example, as of December 31, 2023, EV sales in Washington since 2011 totaled 135,743.[24] EV sales in Oregon totaled 61,535 vehicles over that same period. Through the end of 2021 (the most current data available), registrations of all light-duty vehicles totaled 1,357,126 in Oregon and 2,977,074 in Washington. EVs thus represented 4.5% and 4.6% of all registered vehicles in the two states, respectively, at the end of 2023.[25] We assume all internal combustion vehicles will have been retired by 2050 and thus that all vehicles will be EVs by 2050. (Both states participate in the California Advanced Clean Cars II program, which requires 100% of all new vehicle sales to be EVs beginning in 2035.) To the extent that population and total registrations increase in the two states, the impacts on charging loads will be greater. However, to be conservative, we assume total vehicle registrations remain constant.

Next, we account for differences in driving patterns between the two states. Specifically, according to data published by the Federal Highway Administration, in 2022 (the most recent year for which data are available), the average annual vehicle miles travelled (VMT) by Oregon drivers was 11,780, 20% greater than the average VMT per driver in Washington, 9,819.[26] Because the Avista pilot consisted solely of drivers in Washington State, we adjusted the charging load figures for Oregon vehicles to account for the impacts of the additional VMT per driver in Oregon. The results are shown below (**Figure 3**).

Third, we estimate the peak load impacts for the four categories of charging patterns using the Avista data: weekday commuters, weekend commuters, weekday non-commuters, and weekend non-commuters.[27] As shown, we estimate that a 100% EV future would increase the weekday peak electricity demand by over 14,000 MW.

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[23] Ibid, p. 59. This means that the data shown in Figure 1 reflects an average over the entire sample of EV owners, some of whom do not charge on a given day.

[24] Source: Alliance for Automotive Innovation. Electric Vehicle Sales Dashboard. We focus on battery electric vehicles only because plug-in hybrids are not "zero-emissions" vehicles.

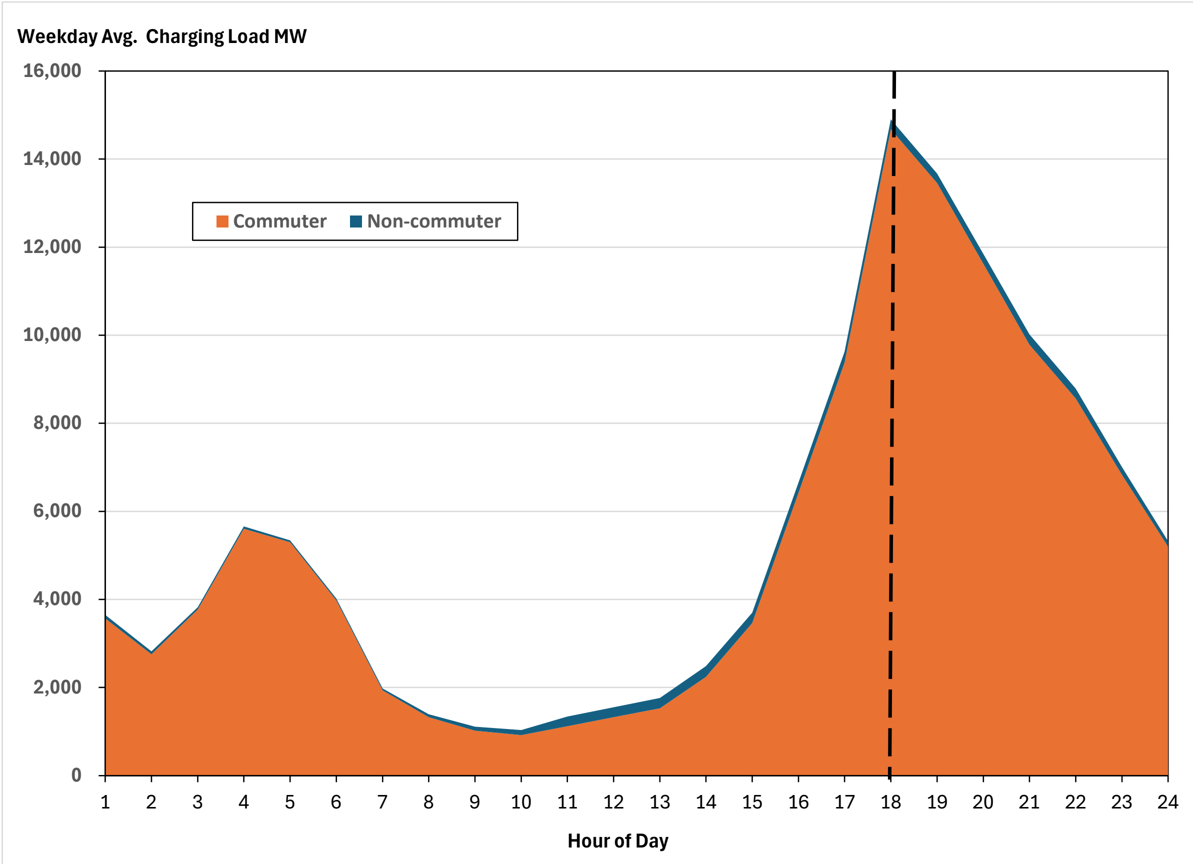
[25] Higher total vehicle registration values would mean EVs represent a smaller percentage of all registered vehicles and thus a 100% EV future would have a greater impact on electricity consumption and peak demand.

[26] Federal Highway Administration, Office of Highway Policy Information, Highway Statistics 2022, Tables VM-2 and DL-201.

[27] For example, 92% of the participants in the Avista study were weekday commuters (and thus weekend non-commuters). To estimate total weekday hourly charging load for a 100% EV future, we use the formula:

$$L_{H,WDC} = D_{i,h,WDC} \times f_{WDC} \times \left[R_O \times (1 + \frac{VMT_O}{VMT_W}) + R_W \times (1 + \frac{VMT_W}{VMT_W}) \right]$$, where $D_{i,h,WDC}$ is the average individual

Figure 3: Estimated Oregon and Washington Weekday Charging Load, 100% EV Future

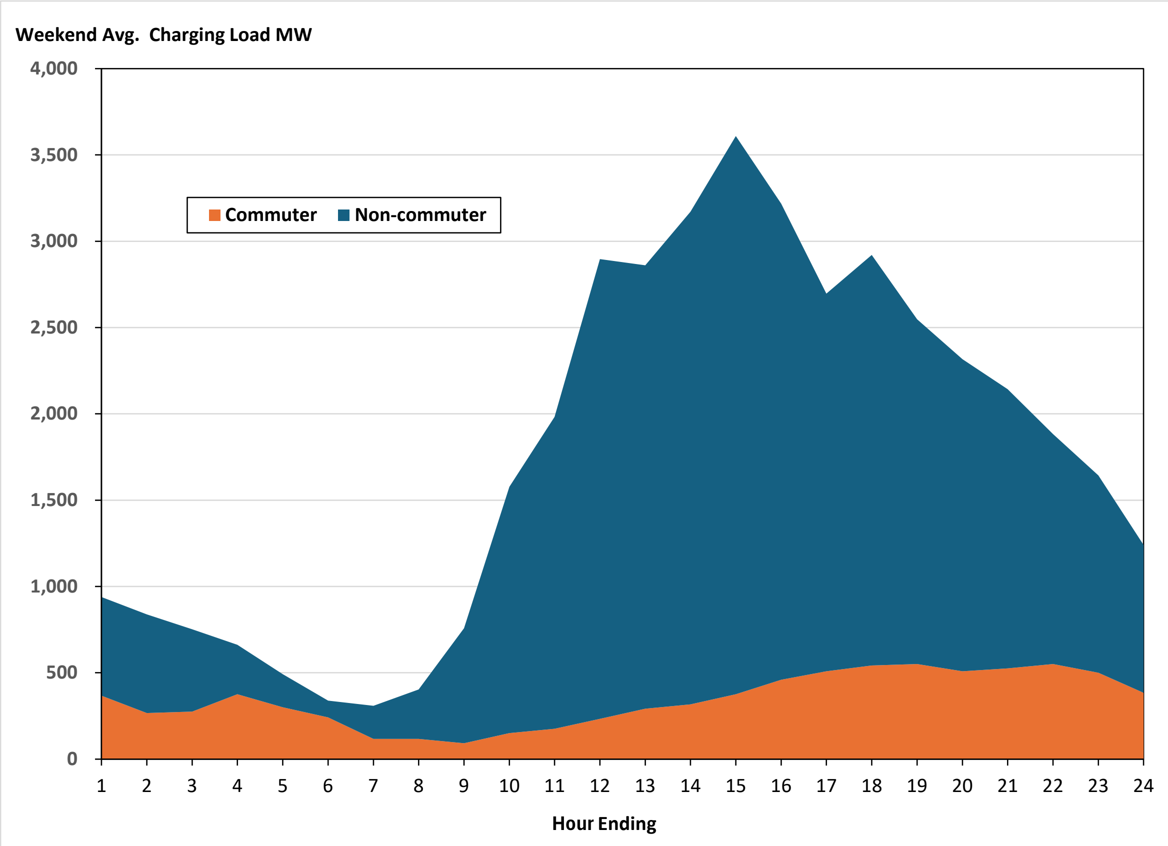


Source: Avista 2019

Although weekday charging will drive the increase in peak electricity demand, to account for the total additional electricity consumption, we must include weekend charging data. The Avista report did not break down data for long-range EVs between weekday and weekend charging. Therefore, to be conservative, we use the weekend data for the non-long-range EVs, while still accounting for the difference in VMT per driver for the two states (**Figure 4**).

weekday charging demand during hour h, f_{wdc} is the fraction of weekday commuters as a percentage of all EV owners, R_O and R_W refer to the number of current vehicles registered in Oregon and Washington, respectively, and VMT_O and VMT_W are average annual vehicle miles traveled by Oregon and Washington drivers, respectively.

Figure 4: Estimated Oregon and Washington Weekend Charging Load, 100% EV Future



Source: Avista 2019

Total daily electricity consumption for EV charging equals the area under the curves for commuters and non-commuters, weekdays and weekends. The additional annual electricity consumption multiplies the weekday values by 260 and the weekend values by 104, totaling 38,057 gigawatt-hours (GWh) (**Table 1**).[28] By comparison, in 2023, total electricity consumption in the two states was about 143,000 GWh.[29] Thus, accounting only for light-duty vehicles, a 100% EV future will increase electricity consumption in the two states by 27% over 2023 levels.

Table 1: Additional Annual Electricity Consumption, 100% EV Future

	Weekday Commuter	Weekday Non-Commuter	Weekend Commuter	Weekend Non-Commuter	TOTAL
MWh/Day	125,780	3,715	8,231	33,967	--
GWh/Year	32,703	966	856	3,533	**38,057**

28 One GWh = 1,000 MWh = 1,000,000 kWh.

29 Source: U.S. Energy Information Administration, Electric Data Browser.

The estimates of increased electricity consumption in Table 1 do not include the impacts of electrification of commercial vehicles, buses, and heavy trucks, as there does not appear to be publicly available data on charging profiles from such vehicles. Moreover, few, if any, electric tractor-trailers are currently in service.

Both Oregon and Washington have a "Clean Trucks" program that requires increasing percentages of new commercial trucks to be electric. By 2035, Washington will require 55% of all new "Class 2b-3" vehicles, 75% of all Class 4-8 vehicles, and 40% of Class 7-8 Tractor sales sold to be electric.[30] Although the number of commercial trucks is far smaller than passenger vehicles, their battery capacities are far larger, and they likely will be charged daily, typically at night. Hence, the estimates in Table 1 should be viewed as conservative.

Estimating the Additional Electricity Demand Associated with Building Electrification

Oregon and Washington also have policies to electrify residential and commercial space and water heat. The plan is to replace fossil fuel space and water heating systems (i.e., natural gas, bottled gas, and fuel oil) with electric heat pumps.[31] We use the 2022 American Community Survey (ACS) data published by the U.S. Census to estimate the impact of space heat electrification on single-family and multi-family homes.[32] Of the approximately 1.2 million single-family homes in Oregon and 2.1 million in Washington State, approximately 40% and 45%, respectively, are heated with electricity (**Figure 5**).[33] In both states, natural gas space heat is present in about half of all households, with small percentages of households using fuel oil or wood. A small percentage of households report having no space heat.

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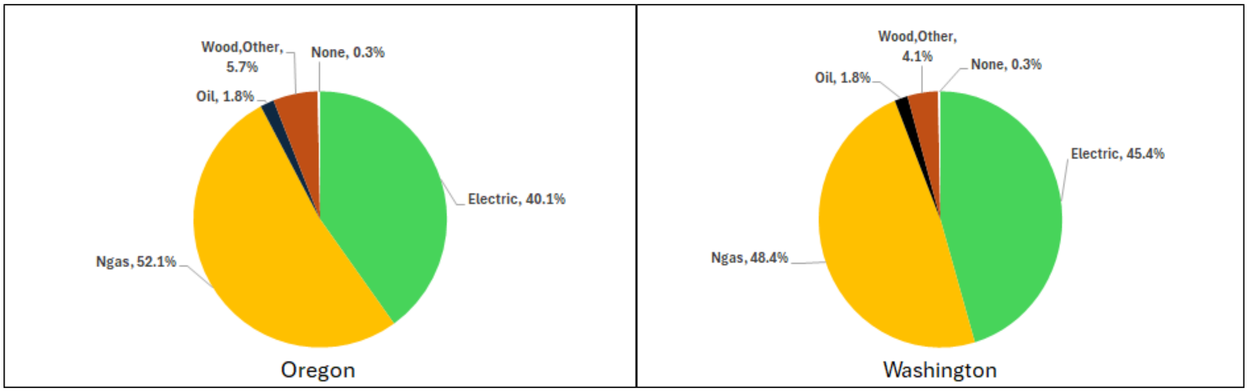
30 Susan Woodward, "Electric trucks to join state's clean transportation future," Washington State Department of Ecology, April 6, 2023. The percentages for Oregon are identical.

31 A heat pump works like a refrigerator in reverse: it extracts heat from outside air and delivers that heat inside.

32 Census data are available from IPUMS USA.

33 Approximately 3,000 single-family homes reported using solar as their heating source. We assume these homes will not install electric heat pumps. Because the Census data do not provide a breakdown of water heating fuel, we assume that all homes with natural gas space heat also use natural gas for water heating.

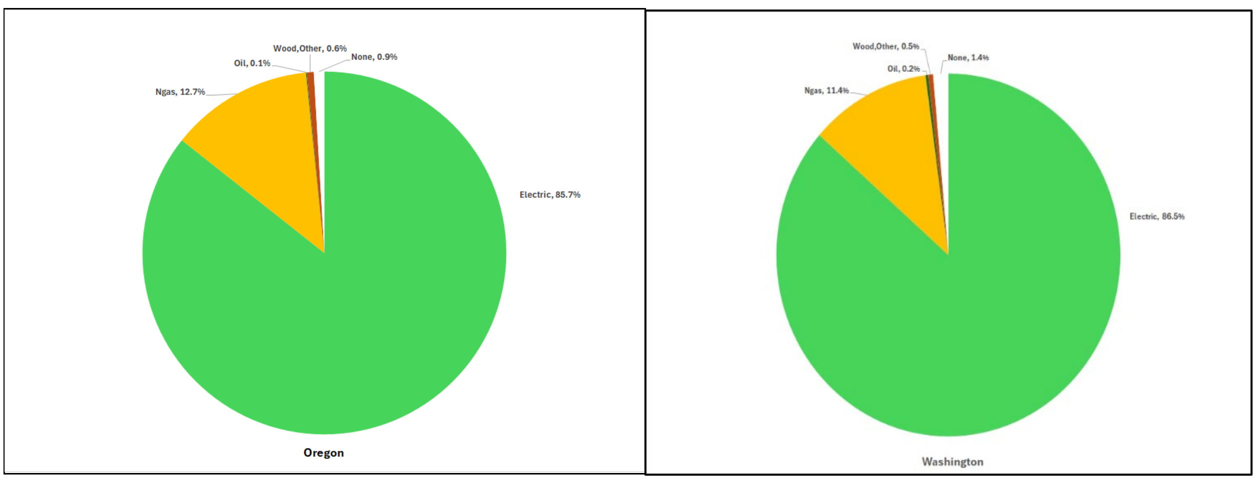
Figure 5: Breakdown of Single-Family Home Heating Fuels



Source: U.S. Census, IPUMS

In contrast to single-family homes, multi-family homes in both states are heated predominantly with electricity, with natural gas heat accounting for about 13% and 11% in Oregon and Washington, respectively (**Figure 6**).

Figure 6: Breakdown of Multi-Family Home Heating Fuels



Source: U.S. Census, IPUMS

To be conservative, we assume no additional growth in housing stocks to estimate the impacts on future electricity peak demand and consumption. The load shape for heat pumps is based on a simulation model, known as the "Simplified Energy Enthalpy Model" (SEEM), which is described in a 2019 report prepared by PNUCC and the Northwest Gas Association.[34]

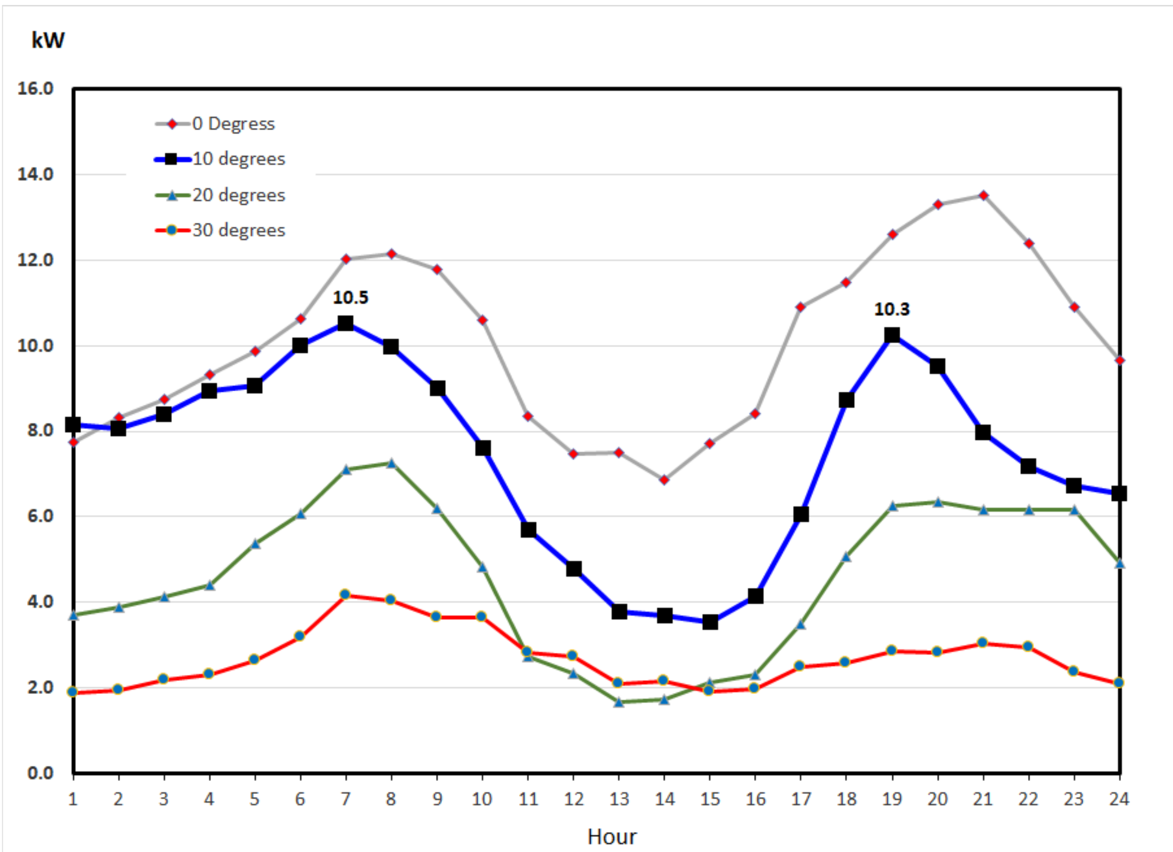
The report estimates daily load shapes for heat pumps of different sizes and different outside temperature conditions. Moreover, because heat pump efficiency decreases as temperatures fall (because there is less

34 PNUCC/NWGA Power & Natural Gas Planning Taskforce, "A Discussion on Electrifying Light Duty Vehicles and Natural Gas Heating in the Northwest," June 2019 (PUCCC/NWGA 2019), p. 15, Figure 9. The SEEM model is described in Appendix A of the publication.

heat to extract from the outside air), many homes will have secondary heating sources. In a 100% electrification scenario, that backup source is likely to be electric resistance heat. On the coldest days, households are likely to use both heat pumps and a secondary heat source. If the secondary source is electric resistance heat (e.g., one or more room space heaters), then peak demand will increase even more.[35]

The daily load profiles for typical air-source heat pumps at different average temperatures are provided in the PNUCC/NWGA 2019 report and reproduced below (**Figure 7**).

Figure 7: Heat Pump Daily Load Profiles



Source: PNUCC/NWGA 2019

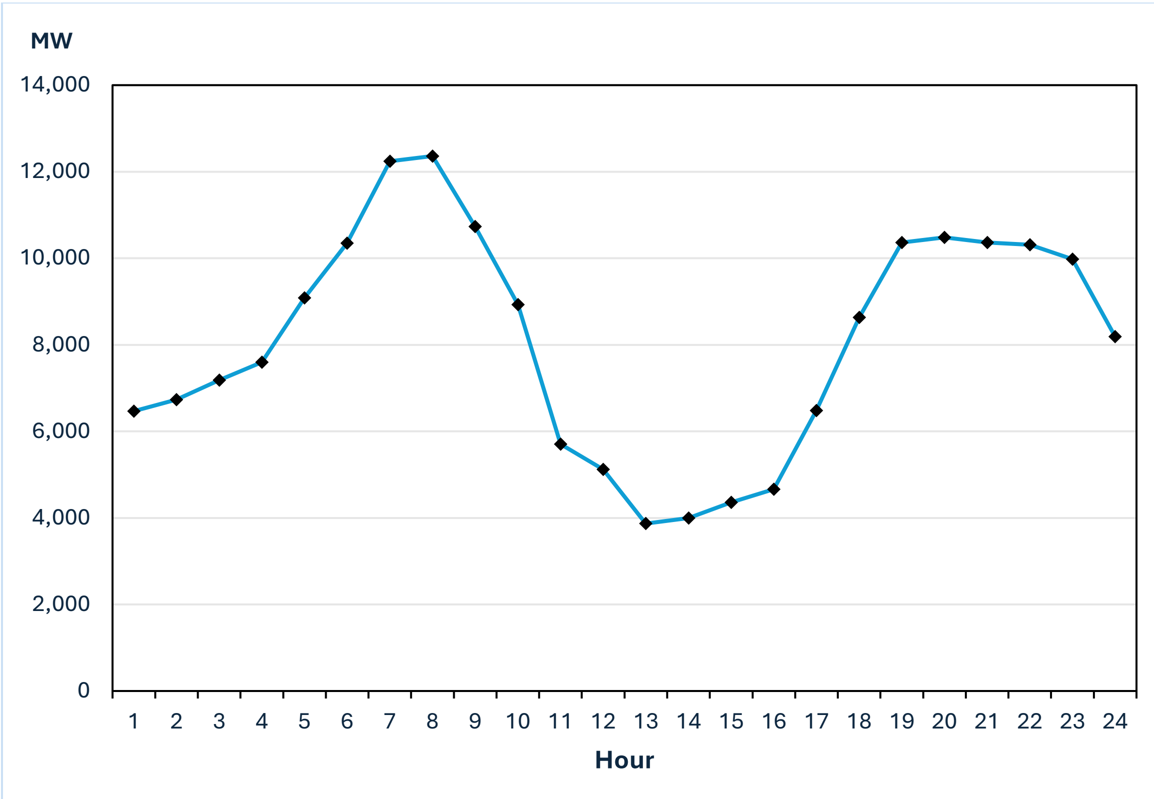
The profiles are based on average daily temperatures in 2023 for Seattle, Portland, and Spokane. The lowest daily average for these three cities was 23° Fahrenheit. At that average temperature, individual heat pump load peaks at an average of 6.3 kW between 6 and 7 AM, and 5.3 kW between 7 and 8 PM.[36]

35 The SEEM model appears to account for secondary heating sources. The E3 model does not.

36 A 2018 study prepared by E3 estimated peak demand of around 7.8 kW using a different simulation model. See E3 "Pacific Northwest Pathways to 2050," November 2018.

Assuming complete electrification of all single-family and multi-family heating, the overall addition to peak demand on such a day will be just under 12,400 MW.[37]

Figure 8: Additional Peak Demand, Full Space and Water Heating Electrification



Source: PNUCC/NWGA 2019, U.S. Census, and author calculations

Estimating Additional Annual Electricity Consumption of Heat and Hot Water Electrification

Total annual heat pump electricity use will depend on temperatures throughout the year. To estimate this, we use historical daily average temperatures in Seattle, Portland, and Spokane, the daily load profiles shown in Figure 7, and assumptions about heat pump efficiency.[38] This resulted in a 14,787 GWh increase in annual electricity consumption with a maximum 12,362 MW peak load. If this estimate coincided in the same hour as the increase in peak demand from EVs, it would increase peak load by 27,300 MW.

To gauge the reasonableness of this approach, we compare it to an estimate of the end-use energy delivered by residential fossil fuels for space and hot water heating. According to the EIA, in 2022,

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[37] The calculation equals the daily average heat pump load multiplied by the number of homes within the two states that use fossil fuel for heating.

[38] R. Johnson, "Measured Performance of a Low Temperature Air Source Heat Pump," U.S. DOE, Building Technologies Office, September 2013.

residential natural gas deliveries totaled 209.3 trillion Btus (TBtus).[39] Assuming an average efficiency for natural gas furnaces and water heaters of 80% (newer ones have efficiencies up to 95%), this implies 167.3 TBtus of useful energy for space heat and hot water. As one kilowatt-hour of electricity is equivalent to 3,412 Btus, this is equivalent to 49,000 GWh of electricity. If heat pumps supply all of this electricity, then the total amount of electricity consumed by those heat pumps will depend on the average coefficient of performance (COP). COP values decrease as outside temperatures decrease because less heat energy can be extracted from the outside air.

For this comparison, we assume an average annual COP of 3.0 for heat pumps that will be installed in the two states. Consequently, the estimated additional annual electricity consumed for electrified space and water heating in the two states will be 49,000 GWh / 3.0, or just over 16,000 GWh. (This estimate excludes the additional electricity required for electrifying commercial heat and hot water use.)

Adding this estimate to the 38,057 GWh of additional electricity needed to charge the two states' EVs means a total increase in electricity consumption of 54,057 GWh, representing a 40% increase over 2023 electricity sales in the two states.[40]

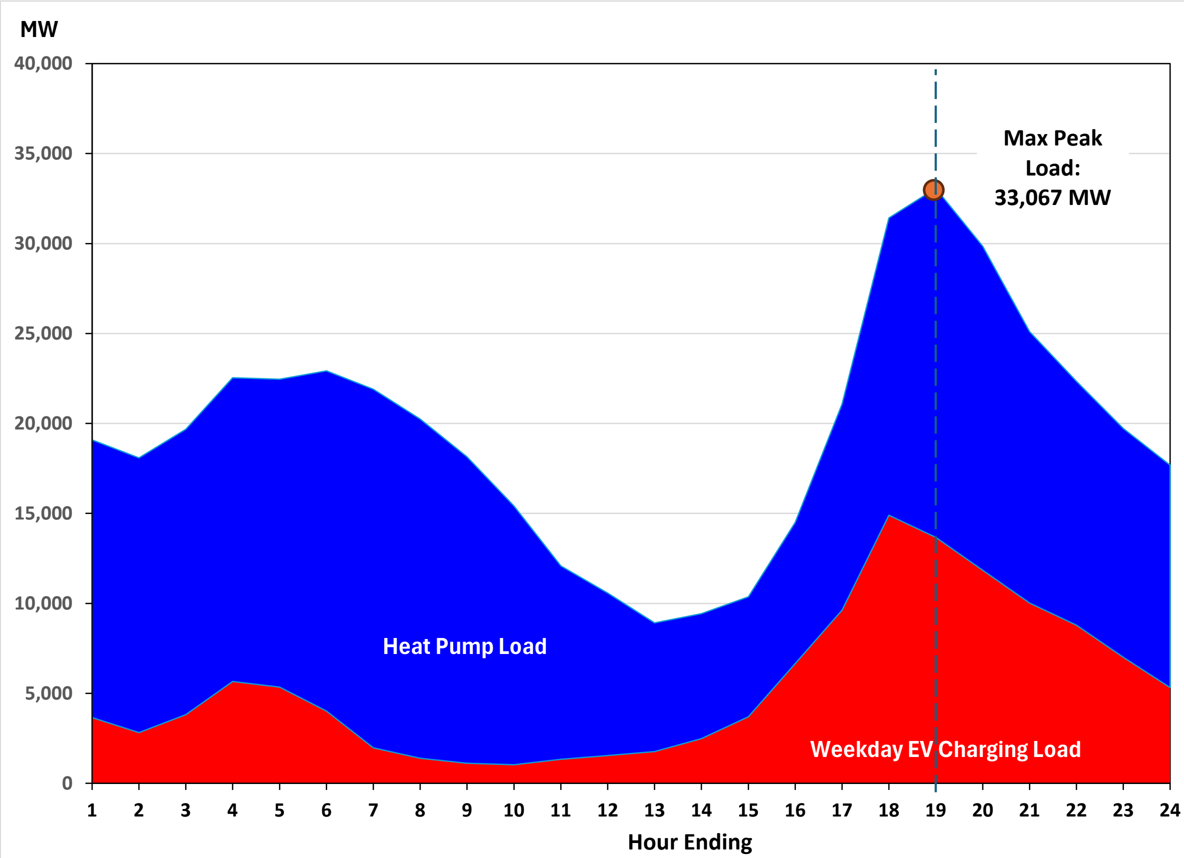
As shown in **Figure 8**, the early evening peak for heating load coincides with peak EV charging loads. This comparison estimated an additional increase in weekday peak electric demand of over 33,000 MW (Figure 9), more than the peak load in the two states in 2023.[41] Hence, because EV charging and heating loads closely coincide, peak demand would likely double over 2023 peak demand due to full electrification.

[39] Source: EIA, State Energy Data System. Total residential heating oil was approximately 6 TBtus, which we exclude from the analysis.

[40] Source: EIA, Electricity Data Browser.

[41] Source: EIA, Hourly Electric Grid Monitor.

Figure 9: Combined Weekday EV Charging and Heat Pump Impact on Peak Electric Demand



Source: Authors' estimates.

ESTIMATING THE ADDITIONAL COSTS OF NEW GENERATION AND STORAGE

Supplying the additional electricity required for electrification and ensuring sufficient generating capacity to meet peak charging and heating demands will require new generating and storage resources, especially if the two states eliminate all fossil generation. We estimate the additional generation capacity and storage required, assuming consumers and businesses maintain control over the timing charging EVs when they wish, heating their homes, and so forth.

Emission-free generating options include nuclear power and renewable generation, principally wind, both onshore and offshore, and solar photovoltaics. Both states obtain large amounts of electricity from hydroelectric dams, especially the federally-owned dams on the Columbia River. However, given the current political climate in the two states, there is virtually no chance that any new large storage dams will be constructed. Instead, environmentalists have succeeded in removing some dams, such as four dams on the Klamath River in southern Oregon and northern California, whose removal was completed this summer.[42] Although environmentalists also seek to remove the four dams on the Lower Snake River, to be conservative in our cost estimates, we assume these efforts will be unsuccessful.

Consistent with the goal of emissions-free energy, there are no proposed new gas-fired generators in either state. Instead, both states assume electricity demand will be met with wind generation (onshore and offshore), and solar photovoltaics.[43] To meet electricity demand when these resources are unavailable (e.g., at night and in periods of calm winds), battery storage, pumped-hydroelectric storage, and emissions-free dispatchable generators (think gas turbines fueled by hydrogen, which do not yet exist) are envisioned. Additionally, both states require energy efficiency investments to reduce peak demand and overall electricity consumption.

As for nuclear power, Energy Northwest, the successor to the Washington Public Power Supply System and owner of the 1,200 MW Columbia Generating Station nuclear plant, signed an agreement last year to build up to 12-100 MW modular nuclear reactors developed by X-energy. The first reactor is scheduled for completion in 2030. However, environmentalists strongly oppose the proposal.[44] New nuclear plants are also banned in Oregon by law under a 1980 voter initiative which prohibits the construction of any new nuclear plants in the state until a permanent federal nuclear waste depository is built.[45, 46] Given the current political climate in both states, we assume no new nuclear plants will be built.[47]

Another potential source of emissions-free energy is thermal. Recent legislation in Washington State allows natural gas distribution utilities to develop thermal energy networks. These networks consist of ground-source heat pumps that deliver heat and hot water through pipes to local areas.[48] In theory, these networks would reduce electricity demand. However, we are unaware of any cost estimates for building

42 U.S. Dept. of the Interior, Detailed Plan for Dam Removal – Klamath River Dams, July 2012; Abigail Lowell, "Klamath Dam Removal & River Restoration Timeline," Environmental Protection Information Center, April 15, 2024.

43 Although geothermal power plants could be constructed, none of the utilities' integrated resource plans propose constructing any such plants and we are unaware of any plans by non-utility developers to construct such plants. Hence, for our analysis, we assume no new geothermal capacity will be constructed in either state.

44 Jerry Cornfield, "WA governor urged to veto $25M for nuclear power project," Washington State Standard, March 27, 2024.

45 Sudeshna Pal, "Will Oregon See a Nuclear Comeback?" Oregon Citizens Utilities Board, December 9, 2021.

46 Micah DeSilva, "Let Oregon Voters Reconsider Nuclear Power," Cascade Policy Institute, August 16, 2023.

47 PacifiCorp plans to contract with Terra Power to build 500 MW of nuclear generation in Wyoming by 2030, 2023 Integrated Resource Plan, Volume 1, March 31, 2023.

48 HB 2131. Curiously, the 2023 Washington State Biennial Energy Report makes no mention of thermal energy networks.

such networks in either state. Moreover, it is not clear what their capacity would be if built.[49] Hence, our analysis does not consider thermal energy as a resource.

Other technologies, such as dispatchable emissions-free resources (DEFRs) fueled with green hydrogen, have yet to be invented. Hence, claims that thousands of MW of such generators will be deployed to meet peak electric demands are entirely speculative. Producing hydrogen, green or otherwise, requires more energy than is contained in the hydrogen itself; that is a thermodynamic fact that cannot be overcome. Moreover, manufacturing hydrogen via electrolysis using wind and solar power is extremely costly.[50] Thus, we assume no DEFRs will be constructed, despite the Washington State Department of Commerce's promotion of green hydrogen as an energy resource.[51]

Methodology[52]

We estimate the costs of the additional generation and storage capacity required to meet the forecast increase in electricity consumption and peak demand by 2050 in two scenarios. The first assumes that electricity demand will be met only with renewable resources: wind, solar, and existing hydroelectric plants, plus battery storage and pumped storage (the "RO Scenario"). The second scenario assumes no additional wind and solar resources are built. Rather, the increased electricity requirements are met with a mix of nuclear generation (including large nuclear plants and small modular reactors (SMRs)); natural gas generators (both combined-cycle plants and combustion turbines); and existing hydroelectric plants (the "NGN Scenario"). Under both scenarios, we assume conservatively that all federal hydroelectric generation is available to Oregon and Washington, even though some of that generation is sold to public entities in Idaho, Montana, Wyoming, Utah, Nevada, and California, as well as returning some generation to British Columbia under the provisions of the 1964 Columbia River Treaty.[53]

Existing generating capacity in the two states totals just under 49,000 MW. To meet anticipated load growth, especially increased peak demand, the model determines the amount of generating capacity that must be built to meet current reliability standards, and then determines the least-cost mix of that capacity based on the resources' costs and performance. This is done based on the average hourly load profile for

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49 There are theoretical studies of such networks. See, e.g., M. Pans, et al., "Theoretical cost and energy optimisation of a 4th generation net-zero district heating with different thermal energy technologies," *Sustainable Cities and Society* 100, January 2024. This study estimated an average cost per dwelling of over $13,000.

50 Jonathan Lesser, "Green Hydrogen A Multibillion-Dollar Energy Boondoggle," Manhattan Institute, February 1, 2024.

51 Washington State Dept. of Commerce, "Green Electrolytic Hydrogen and Renewable Fuels: Recommendations for Deployment in Washington," January 5, 2024.

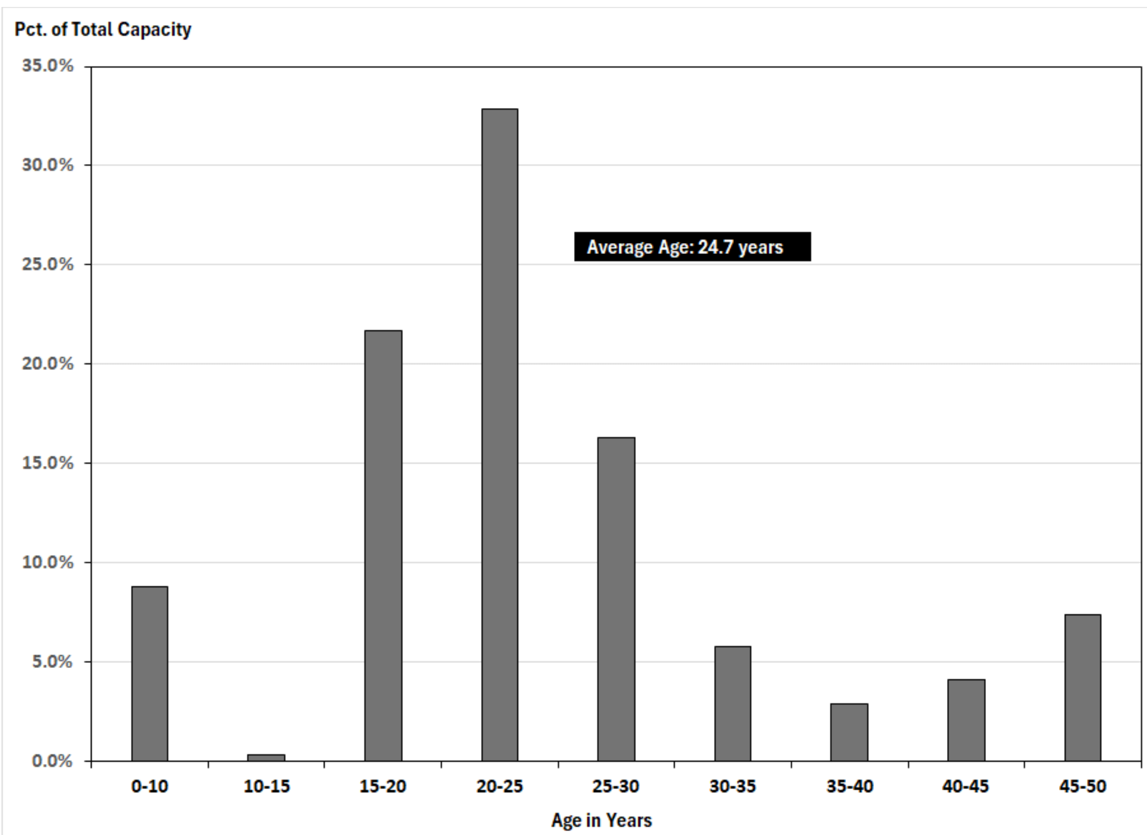
52 The Appendix provides a more detailed description of the modeling methodology.

53 For a discussion, see John Krutilla, *The Columbia River Treaty*, (Resources for the Future, 1967.) See also, Jonathan Lesser, "Resale of the Columbia River Treaty Downstream Benefits: One Road from Here to There," *Natural Resources Journal* 30 (Summer 1990), pp. 609-628.

the two states during 2023, adjusted for the forecast increase in hourly loads from EV chargers and heat pumps.

Under each scenario, we assume the Centralia coal-fired power plant in Washington will close next year, as scheduled. We also assume the Columbia Generation Station closes in 2046 when its operating license expires. For the renewable generation scenario, we model retirements of existing gas generators based on the two states' zero-emissions generation laws, and those generators' ages, which average about 25 years (**Figure 10**). To model retirements of these generators, we assume generators 45 years and older are retired in 2030, generators 35-40 years old are retired in 2035, all Oregon natural gas generators and Washington State generators that are 25-30 years old are retired between 2036 and 2040, and the remaining gas generators in Washington State are retired between 2041 and 2045. (For the natural gas and nuclear scenario, we assume the zero-emissions laws are repealed and generators are retired when they are 40 years old.) In both scenarios, we assume existing geothermal and biomass generation continue through 2050.

Figure 10: Age Distribution of Existing Natural Gas Generators



Source: U.S. EIA, Form-860, May 2024.

As loads increase with increased electrification, we assume new generating resources are built in the two states. Although out-of-state resources could be added, those will have higher transmission costs to deliver the electricity produced west of the Cascades, where most of the electricity will be consumed.

Moreover, under the natural gas and nuclear scenario, we assume new resources can be located near load centers (e.g., Seattle, Portland, Spokane).

Although a half-dozen pumped storage facilities have been proposed to be built in Oregon, most are in the preliminary feasibility and permit stages. The exception is the 400 MW Swan Lake project,[54] scheduled to be operational in 2028.[55] The proposed 1,200 MW Goldendale Pumped Storage project near the John Day dam in southern Washington State is awaiting approval of its Final Environmental Impact Assessment, but environmental groups and several Native American tribes oppose the project.[56] (As we write this, it is uncertain whether the project will be approved and, if so, when it will enter service.[57]) Therefore, we include the Swan Lake pumped storage facility only.

Under the RO Scenario, the need for new generating capacity will be exacerbated by wind intermittency, longer-term wind "droughts" that have been observed historically, and the fact that solar photovoltaics do not provide electricity at night, including early evening hours when electricity demand peaks. Moreover, planners in the Pacific Northwest also evaluate the need for new resources to offset periods of low hydroelectric generation, such as those experienced in the drought conditions during the 2023 water year.[58] Thus, to meet electric needs in the two states, wind and solar generation must be overbuilt to account for these resources' inherent intermittency and to provide surplus electricity for battery storage facilities that will be needed to ensure sufficient electricity to meet demand.[59]

To determine the wind, solar, and storage capacity needed to meet the full electrification scenario by 2050, we use hourly electricity data from 2023 published by the U.S. Energy Information Administration. These data provide a baseline load profile. We then adjust that load profile to account for the change in peak demand based on the charging patterns for EVs and space and water heat, assuming the all-electric scenario described previously. This creates an estimated hourly electric load profile in 2050.

We then determine a least-cost mix of solar PV, wind, and storage capacity to serve this hourly load profile using observed hourly data for wind and solar generation in the two states to determine expected annual

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54 Federal Infrastructure Projects, Permitting Dashboard.

55 Oregon Energy Facility Siting, Project Updates, July 2024.

56 Courtney Flatt, "Controversial energy project in southern Washington state moves closer to breaking ground," Oregon Public Broadcasting, February 10, 2024.

57 The earliest feasible date for the project to become operational is 2028.

58 Scott Disavino, "US Pacific Northwest water supplies fall to 22-year low in 2023," Reuters, October 3, 2023. See also, Karin Bumbaco, et al., "2023 Pacific Northwest Water Year Impacts Assessment," National Integrated Drought Information System, 2024.

59 We do not evaluate efforts by utilities and policymakers to "manage" peak electric demand through alternative rate structures (charging high prices when demand is greatest) or direct load controls, in which utilities have the ability to restrict or prevent the usage of EV chargers, electric heat pumps, etc. when demand peaks. Although peak demand can be reduced, these programs cannot reduce total consumption except through higher average prices.

generation, but more importantly, hourly generation available to meet demand. The hourly wind, solar, and wind drought data determine the storage capacity required to ensure that demand is always met.[60]

We determine the least-cost mix of generation and storage capacity by evaluating alternative wind, solar, and storage capacity combinations that meet forecast demand at all hours. For example, although solar PV is less costly to build than wind turbines, the absence of any solar generation at night means more storage capacity must be built. Similarly, an all-wind mix requires enough storage capacity to ensure electricity is available during wind "droughts" when little wind generation is available. Such a wind drought took place in early November 2023 and lasted almost six days.

Capacity Requirements

Assuming the approximately 30,000 MW of hydroelectric generation remains in service through 2050 (i.e., none of the hydroelectric dams in the two states are removed), the least-cost capacity mix in 2050 under the RO Scenario comprises approximately 66,300 MW of wind generation, 147,000 MW of solar PV, and 153,300 MW of storage (**Table 2**). The huge quantities of wind and solar capacity are required to compensate for their inherent intermittency and potential unavailability when electricity demand peaks.[61] Moreover, there must be sufficient wind and solar capacity to provide electricity for battery storage. On average, solar PV only produces electricity in about 25% of all hours, depending on location; production in winter hours is obviously much lower because there are fewer daylight hours and greater in summer. (The average percentage of hours a generator produces electricity over the year is called its "capacity factor.") The capacity factor for onshore wind turbines is around 35%.[62] By contrast, the capacity factor for a typical nuclear plant is over 90%.

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[60] We assume four-hour battery storage facilities, that is, facilities that can supply continuous power at full capacity for up to four hours. We make this assumption because the costs of four-hour batteries are lower than longer-duration ones (e.g., six-hour, eight-hour). We have not modeled storage technologies that are not commercially available because their costs, if commercialized, are unknown.

[61] Under an absolute worst-case scenario in which neither wind nor solar generation is available for an extended period, the storage capacity shown in Table 4 would provide electricity for less than 24 hours on a typical winter day in 2050. However, because the hydroelectric system can provide additional energy when called on, less storage is required.

[62] EIA, Electric Power Monthly, June 2024, Table 6.07B, Capacity Factors for Utility-Scale Generators Primarily Using Non-Fossil Fuels.

Table 2: Current Capacity Mix and Least-Cost Mix in 2050 (MW)

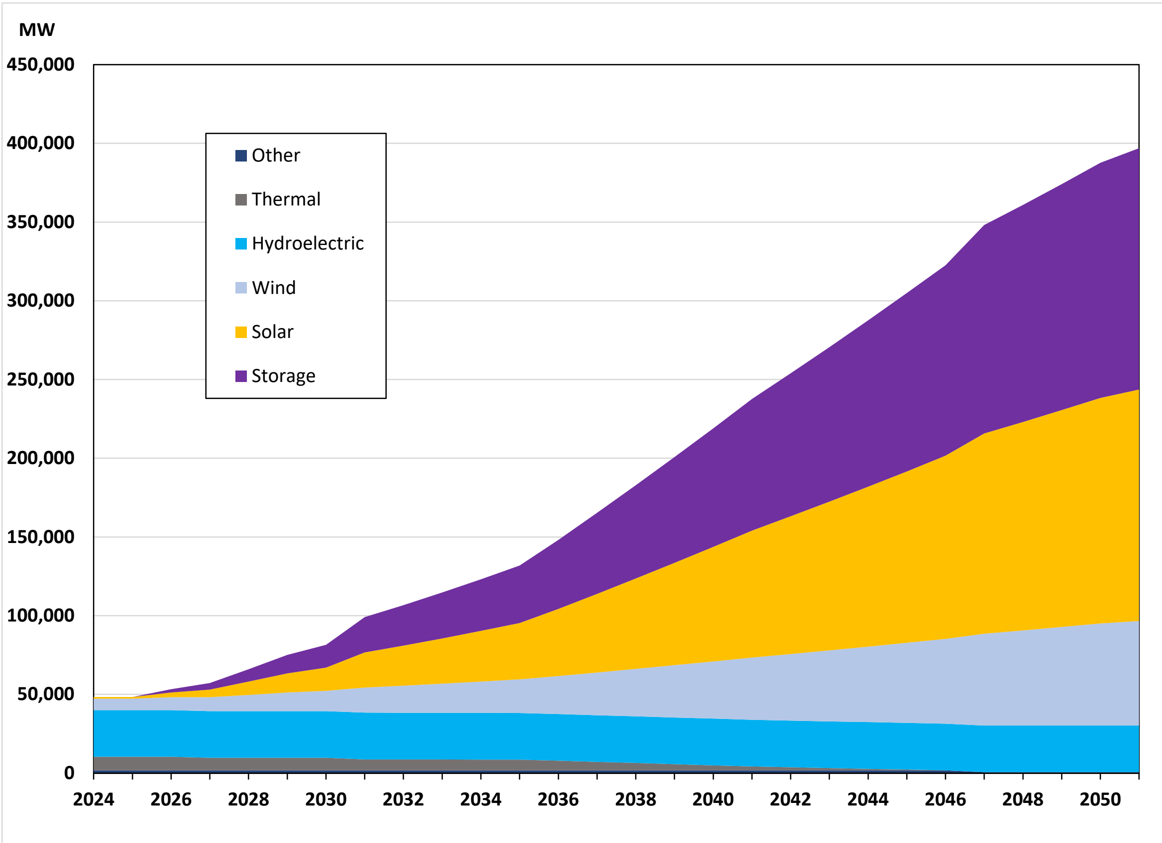
Scenario	Hydro	Thermal[A]	Nuclear	Wind	Solar[B]	Storage[C]	Other[D]	Total
Current Capacity	29,633	9,154	1,200	7,368	1,201	355	596	**48,911**
RO Scenario	29,633	0	0	66,341	147,038	153,342	596	**397,663**
NGN Scenario	29,633	24,159	9,000[E]	7,351	969	2,444	596	**74,856**

Notes:
A- Includes coal, oil, and natural gas.
B- Excludes behind-the-meter solar PV.
C- Includes pumped hydroelectric and battery storage.
D- Includes biomass and geothermal.
E- Assumes that the 1,200 MW Columbia Generating Station nuclear plant is still retired in 2046.

As Table 2 shows, the RO Scenario requires increasing the existing 49,000 MW of generating capacity by more than 700%, while the NGN Scenario requires an increase of about 53%. As shown in the table, under the RO Scenario the least-cost capacity mix will require increasing wind capacity by a factor of nine, solar PV capacity will need to increase by a factor of more than 100, and storage capacity will need to increase by a factor of more than 400. To put this into perspective, an average of about 2,300 MW of wind capacity, 5,600 MW of solar PV, and 5,900 MW of storage will need to be added annually between now and 2050 (**Figure 11**). The additional generating capacity needed under the NGN scenario is far lower, requiring an additional 9,000 MW of new nuclear capacity and about 16,000 MW of new gas-fired generating capacity (**Figure 12**).[63]

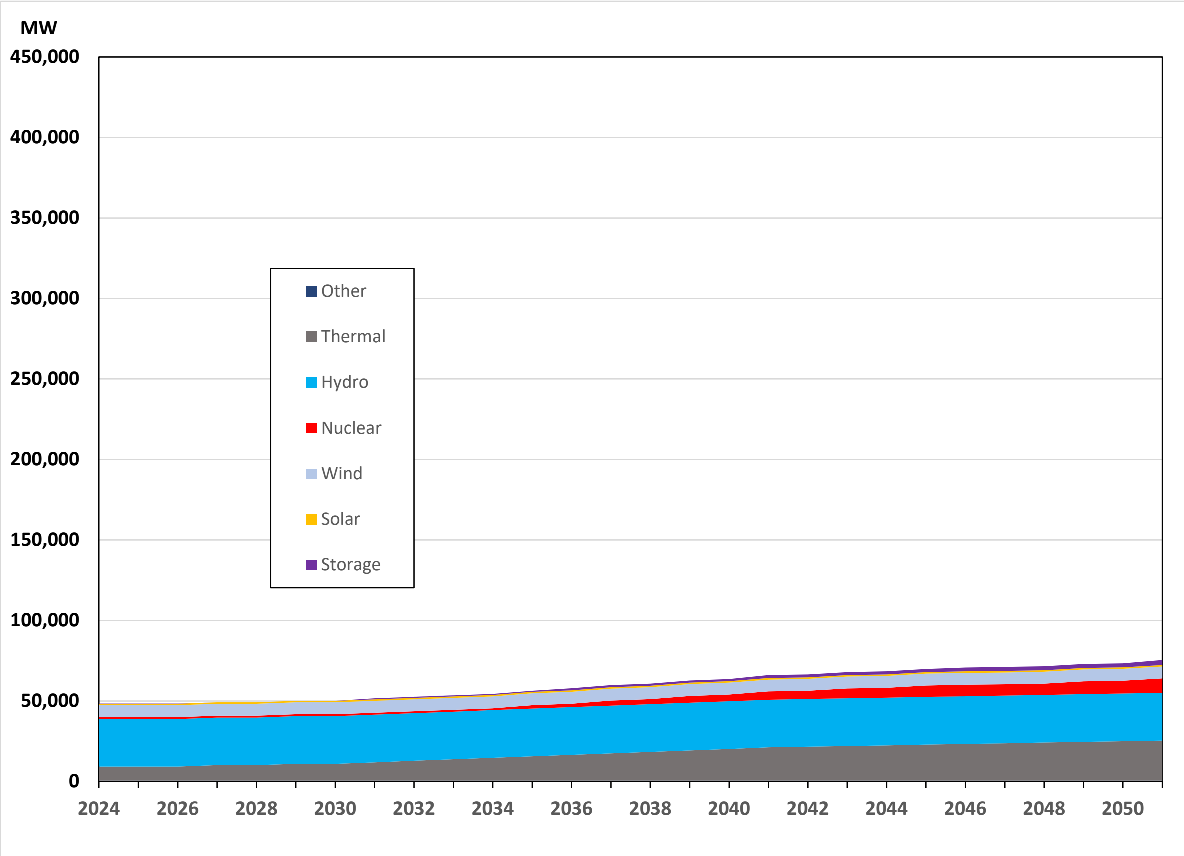
63 These values do not include replacement capacity for generators that are retired between 2024 and 2050.

Figure 11: Annual Generating Capacity, RO Scenario



Source: authors' calculations.

Figure 12: Annual Generating Capacity, NGN Scenario



Source: authors' calculations.

A Note on Land Requirements

The land requirements of the RO Scenario would be extraordinarily large because of the low power densities. Power density is a measure of capacity per unit of geographic area. Nuclear plants have the highest power density of all generating technologies. Solar PV and, especially, wind generation, by contrast, have extremely low power density.

Wind turbines have a power density of about one watt per square meter,[64] equivalent to 2.6 MW per square mile. Thus, in the RO Scenario, the approximately 66,000 MW of wind generation would require over 25,000 square miles of land. Solar PV has a power density of about 6 watts per square meter,[65] equivalent to about 15.5 MW per square mile. Hence, the total land area required for 147,000 MW of solar capacity would be about 9,500 square miles. By comparison, the land area of both states east of the Cascades is roughly 100,000 square miles. Thus, about 25% of the entire area east of the Cascades would be needed if the wind and solar capacity could be co-located and roughly 35% of the entire area if they could not.

Although developing offshore wind would reduce the land area requirement, the high cost of floating wind turbines – estimated to be two to three times greater than traditional offshore turbines – makes it unlikely that they will be built off the Oregon and Washington coasts, where the water is too deep to locate traditional offshore turbines.

Generation and Transmission Costs

To estimate the total costs under each scenario, we assume the two states' investor-owned utilities will build and own all new generating capacity required. Although there are numerous municipal utilities and public utility districts that own hydroelectric plants, those plants are many decades old.[66] More recently, municipal utilities like Seattle City Light have signed purchase contracts for electricity, rather than construct facilities themselves. Hence, we assume new capacity will be built by the two states' investor-owned utilities (IOUs) or private, for-profit entities. Because we assume financing costs for the former will be lower than for the latter, we estimate total costs based on the current capital costs for IOUs.[67]

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64 Vaclav Smil, *Power Density* (Cambridge, MA: MIT Press 2015), p. 67.

65 Ibid, p. 53.

66 Seattle City Light's newest hydroelectric generator is a small 5 MW hydroelectric dam on the Tolt River, which became operational in 1995.

67 Note that we base annual capital costs on the amount of investment that is depreciated each year because this is how a utility's revenue requirement and rates are calculated. Specifically, the revenue requirement is the sum of O&M costs, administrative costs, depreciation, taxes, and a return on undepreciated capital (called "rate base.") For additional detail, see Jonathan Lesser and Leonardo Giacchino, *Fundamentals of Energy Regulation*, 3d ed. (2019).

Unlike most businesses, IOUs do not profit from the amount of product (in this case, electricity) they sell to their customers. Instead, they earn a return on their investments in physical assets before they are fully depreciated. Thus, the more infrastructure a utility builds, the more profits it earns if utility regulators approve those investments. Under this system, the state's IOUs will benefit considerably from an energy transition that forces the closure of still-useful power plants and encourages a major build-out of brand-new generation facilities and transmission lines.

For both scenarios, we use data published by the U.S. Energy Information Administration (EIA) to calculate the costs of new generating capacity, and associated operation and maintenance (O&M) costs (**Table 3**).[68] We also use EIA data on average lifetimes for new generating assets to estimate annual depreciation costs.[69] For existing generators, we rely on cost data published by the Federal Energy Regulatory Commission in annual files that the agency requires electric utilities to submit. Finally, to estimate the costs of new transmission capacity that will be required under the RO Scenario, we use estimated costs for several existing transmission projects and an average estimate of $145,000 per MW of generating capacity by the Bonneville Power Administration, which reflects different locations for new capacity.[70]

Table 3: Generation and Storage Costs (2023$)

Technology	Overnight Capital Cost[A] ($/kW)	Fixed O&M ($/kW-year)	Variable O&M ($/MWh)	Regional Cost Multiplier[B]
Wind	$1,489	$33.06	$0.00	1.059
Solar PV	$1,502	$20.23	$0.00	1.040
Advanced Nuclear	$7,861	$156.20	$2.52	1.087
Small Modular Reactor	$8,936	$121.99	$3.19	1.061
Battery Storage (4-hour)	$1,744	$40.00	$.0.00	1.045

Notes:

A – overnight capital costs exclude all financing costs.

B – reflects the difference from the EIA's estimated national average for generations built in the Pacific Northwest.

The additional costs associated with building new generating capacity are offset in the RO Scenario by reductions in fuel costs and savings on O&M costs. Finally, because many wind/solar/storage proponents

68 EIA, "Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies," January 2024.

69 We assume straight-line depreciation, which is consistent with standard utility regulation. The assumed lifetimes are shown in the appendix.

70 For example, the estimated cost of the 290-mile Boardman to Hemingway line?) has an estimated cost of $1.2 billion, just over $4 million per mile. The 100-mile Cascade Renewable Transmission Project from The Dalles, Oregon, to Vancouver, Washington, has an estimated cost of $1.5 billion, or $15 million per mile. PacifiCorp's Gateway Transmission projects have an estimated total cost of $8.0 billion for 2,300 miles, about $3.5 million per mile. A study by the Bonneville Power Administration estimated an average cost for transmission needed for new renewable generation to be about $0.145 million per MW.

argue that the costs of these technologies will decrease over time, we include a lower-cost renewables scenario. This scenario assumes the capital costs for wind, solar, and storage decrease 2.5% annually on an inflation-adjusted basis, or 50% by 2050, even though the increase in demand for these resources will make large reductions in capital costs unlikely.

The overall cost increase for the RO Scenario totals just under $550 billion (**Table 4**), over six times greater than the increase in total costs of $86 billion for the NGN Scenario. Under the Lower-Cost renewables scenario, the total cost is $418 billion, still almost five times larger than the NGN Scenario. Assuming an annual inflation rate of 2%, the resulting costs total $780 billion for the RO Scenario, $123 billion for the NGN Scenario, and $510 billion for the Lower-Cost renewables scenario.

Table 4: Total Costs for Each Scenario through 2050 (Millions of 2024$)

Scenario	Capital Costs[A]	Fixed O&M Costs	Variable O&M Costs[B]	Taxes	Utility Profits[C]	Total Costs
RO Scenario	$232,791	$73,229	($11,381)	$48,363	$206,909	**$549,910**
Lower-Cost Renewables	$170,488	$73,229	($11,381)	$35,267	$150,884	**$418,488**
NGN Scenario	$17,953	$7,282	$3,226	$10,889	$46,587	**$85,937**

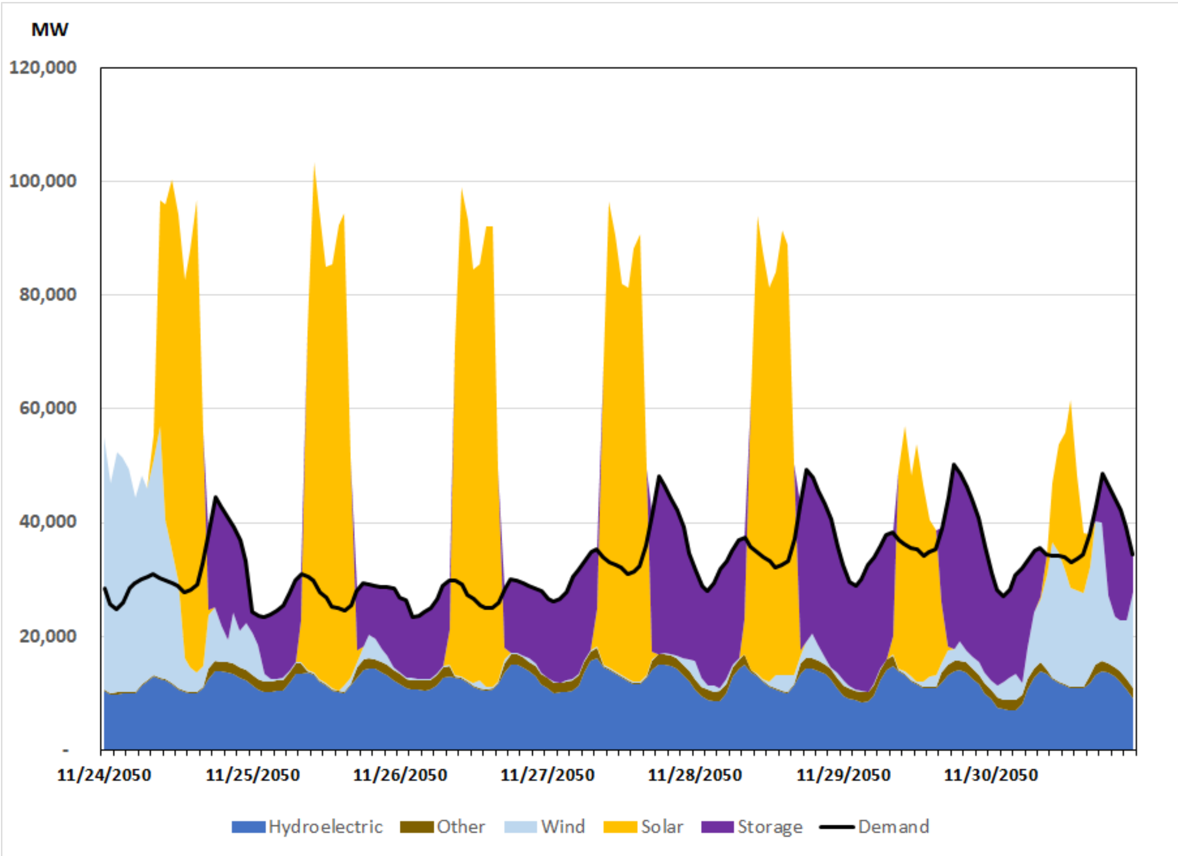
Notes:
A – includes generation and transmission costs.
B – includes fuel costs (savings).
C – based on Puget Sound Energy's current capital structure and approved cost of capital. Includes financing costs and return on equity capital.

Comparison of Load Profiles to Ensure Reliability

As discussed previously, overbuilding of wind and solar will be required to ensure there is sufficient generation and storage to meet electricity demand when there is little wind, solar, or both available. The wind drought that took place over the six-day period, November 24, 2023 – November 30, 2023, provides an example.[71] Using this period, we modeled the need for solar and storage to overcome the lack of wind generation over the six days (**Figure 13**). As shown, large quantities of storage (almost 1.8 million MWh) are required to meet total electric demand (5.5 million MWh).

71 By 2:00 PM on November 24, wind generation fell to about 10% of the level in the early morning hours. It remained low until 5:00 AM November 30, when it began to increase.

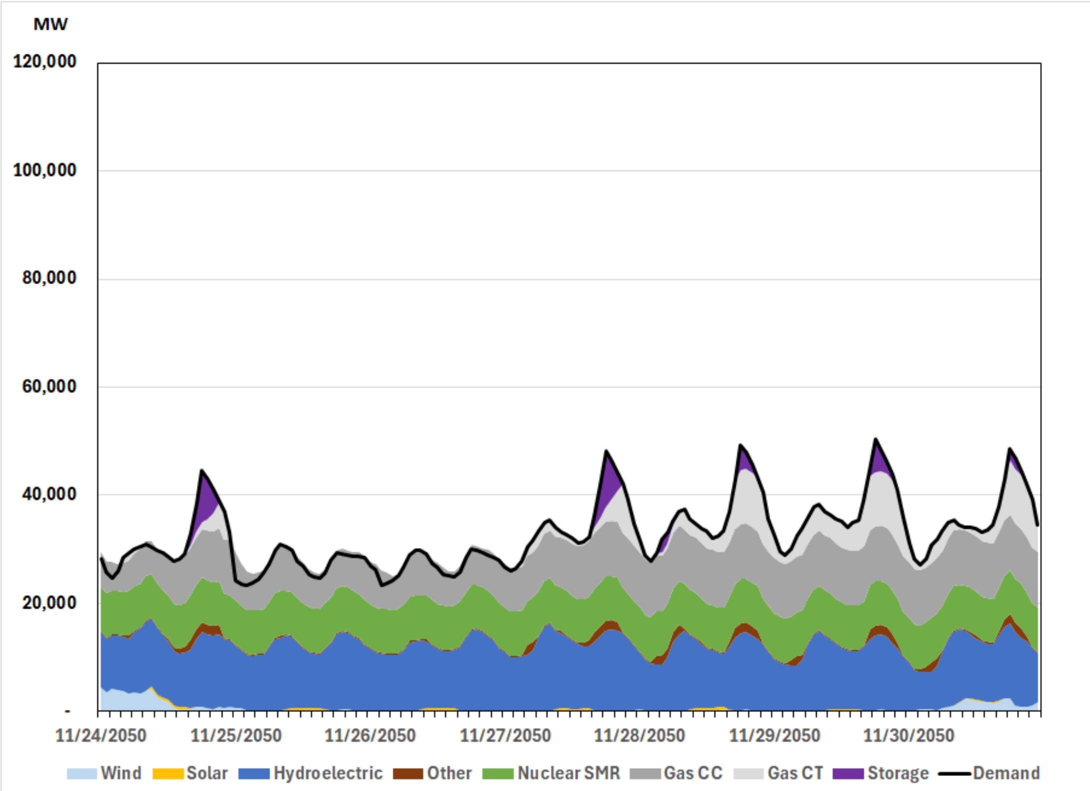
Figure 13: 2050 Hourly Load Profile, RO Scenario During November Wind Drought



Source: authors' calculations.

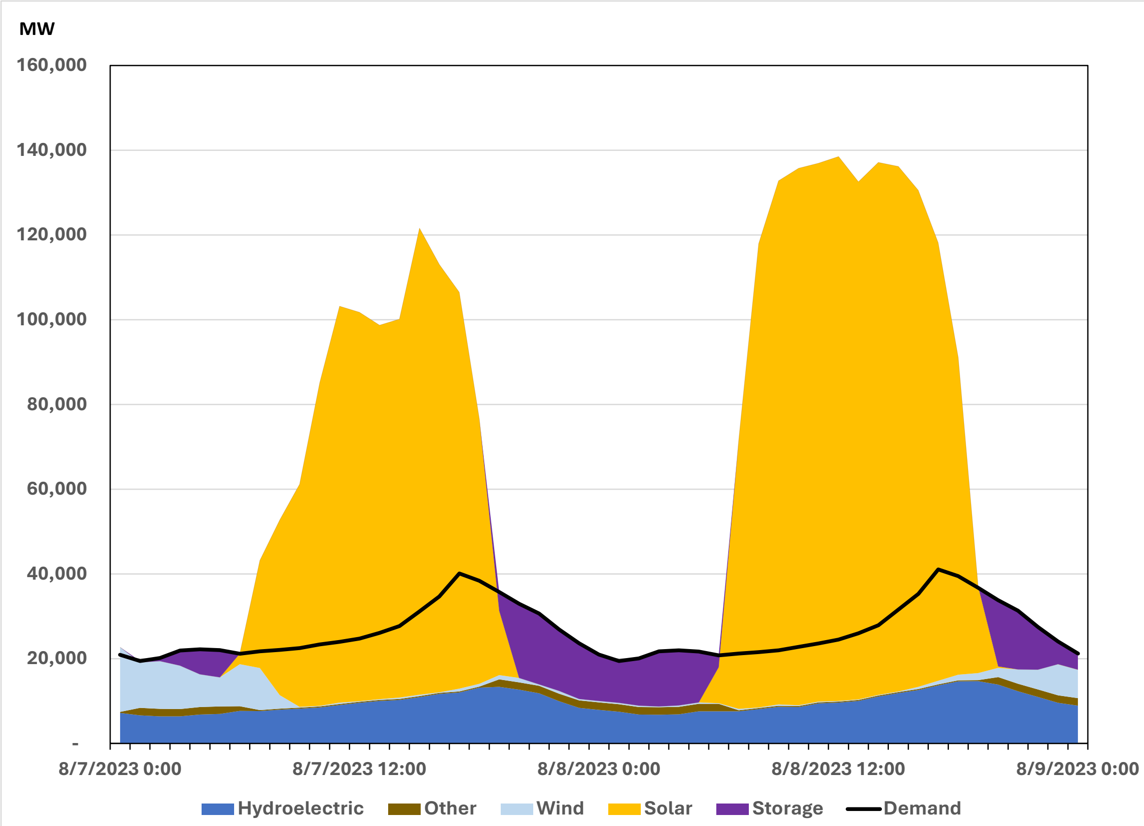
By comparison, the hourly load profile for the NGN Scenario requires just over 94,000 MWh of storage (**Figure 14**). That is, the storage requirement to account for a wind drought is more than 19 times that of the NGN scenario. Similar comparisons exist for both winter and summer peak periods; large quantities of storage are required to compensate for the unavailability of wind and solar. For example, using the August 1-2 hourly demand profile for 2050 and the historical availability of wind and solar during that period, storage is required to supply 250,000 MWh of the total demand of about 1.4 million MWh (**Figure 15).**

Figure 14: 2050 Hourly Load Profile, NGN Scenario During November Wind Drought



Source: authors' calculations.

Figure 15: Load Profile for August 7-8, 2050, RO Scenario



Source: authors' calculations.

RETAIL ELECTRIC RATE AND BILL IMPACTS

The additional generation and transmission required to meet the 100% electrification goals will increase customer rates. (We exclude the costs of local distribution system upgrades that also will be needed to accommodate increased peak demand.) To estimate the rate impacts, we begin with average rates by customer class (i.e., residential, commercial, industrial) in the two states, and the overall average rate as reported by EIA. We assume that the current rate differentials among the different customer classes remain the same.

In 2023, the retail rate paid by all customers in the two states averaged 9.84 cents/kWh, with residential customers paying an average of 11.57 cents/kWh, commercial customers 10.16 cents/kWh, and industrial customers paying an average of 6.68 cents/kWh.[72] These average rates represent a 16% increase over

72 Under full electrification, residential customer peak demand is likely to increase relative to commercial and industrial peak demand based on the patterns of EV charging and space heating. Typical approaches to allocating fixed costs would then assign proportionally more of those fixed costs to residential customers. To simplify the analysis, we have ignored these cost allocation impacts.

average rates in 2020 for all customers; average rates for residential and commercial customers rose by 12% and 13.5%, respectively, between 2020 and 2023, while average rates for industrial customers rose by over 25%.

As new generation and transmission are added each year, rate base (i.e., the net, undepreciated value of utility capital assets) increases. At the same time, continued depreciation of existing generation and transmission causes the rate base to decrease. Because the former overwhelms the latter, the total rate base increases over the 2024 – 2050 period. This increases the return on rate base earned by utilities and the income taxes they pay.[73]

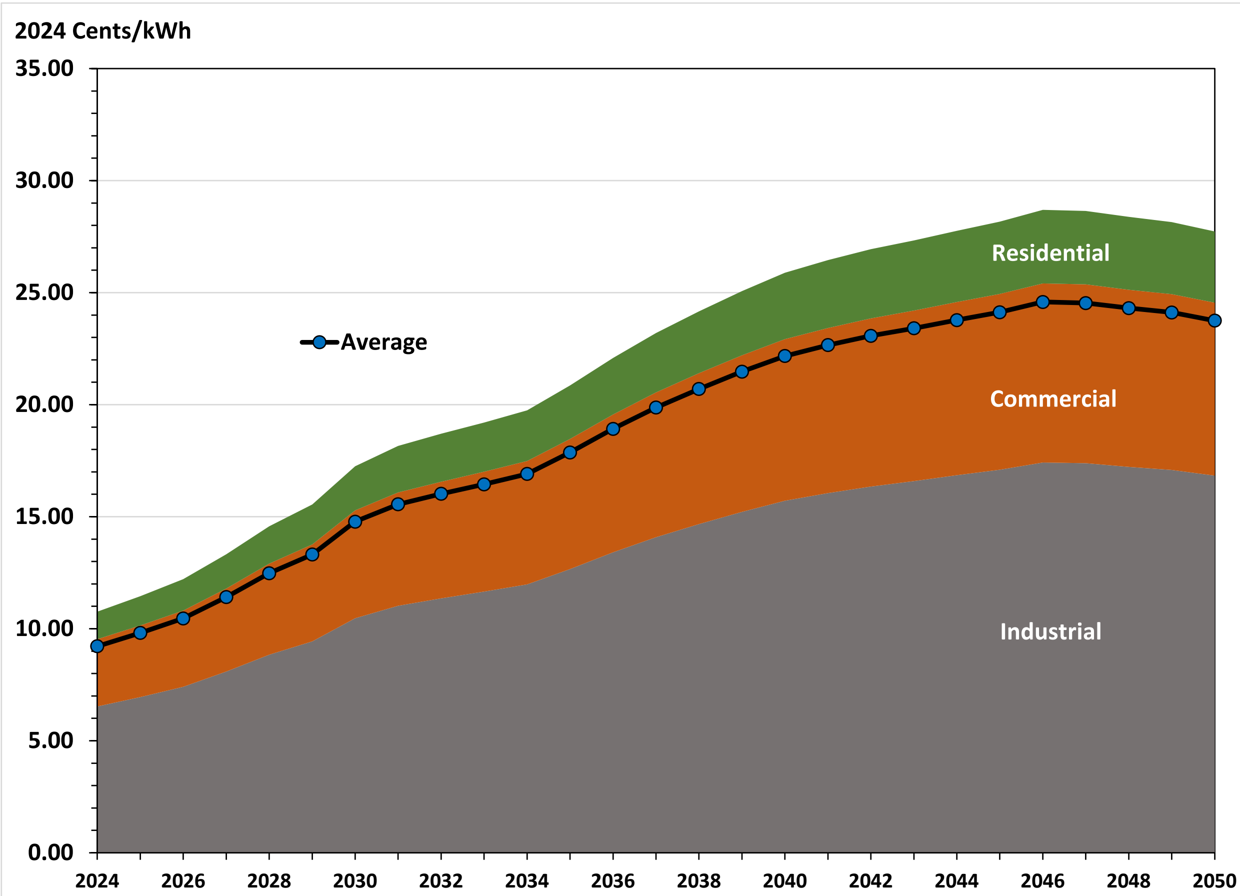
Under the RO Scenario, customer rates will more than double in *inflation-adjusted* terms to 24.6 cents/kWh by 2046 (**Figure 16**). (Because of depreciation and decreased capacity additions, average rates decrease slightly after that year.) Again, this excludes the costs of distribution system upgrades that will be required. Residential rates will increase to 28.7 cents/kWh by 2046, commercial rates will increase to 25.4 cents/kWh, and industrial rates will increase to 17.4 cents/kWh. Assuming an annual inflation rate of just 2.0%, these are equivalent to nominal rates of approximately 48 cents/kWh, 43 cents/kWh, and 29 cents/kWh for residential, commercial, and industrial rates, respectively.

Under full electrification, and assuming an inflation rate of just 2% annually, the average residential customer bill will increase fourfold, from just over $100/month today to over $700/month in 2050. The average commercial customer bill will increase from $600/month today to about $3,800/month, even excluding the additional costs associated with operating commercial EVs and switching to electric heat pumps.

Not only will the two states no longer rely on some of the lowest cost electricity in the nation, but the adverse economic impacts will be widespread. Quadrupling electric rates will raise the cost of producing and transporting goods and the cost of providing services. Virtually everything will be far more costly to produce. This will mean higher levels of energy poverty for consumers, fewer jobs as companies, especially energy-intensive manufacturing ones, migrate to regions with lower-cost electricity, and less agricultural production in the two states. In short, the two states' economies, which have historically relied on some of the lowest-cost electricity in the nation, will no longer enjoy that luxury. While those customers will no longer spend money on natural gas, the savings will be dwarfed by the higher cost of electricity.

[73] We assume the current U.S. corporate tax rate remains at its current level of 21%. Although there are municipal utilities in both states, we do not differentiate between the rate impacts for customers of IOUs and those municipal utilities because we assume transmission and generation investments will be undertaken by the former, or independent, for-profit developers.

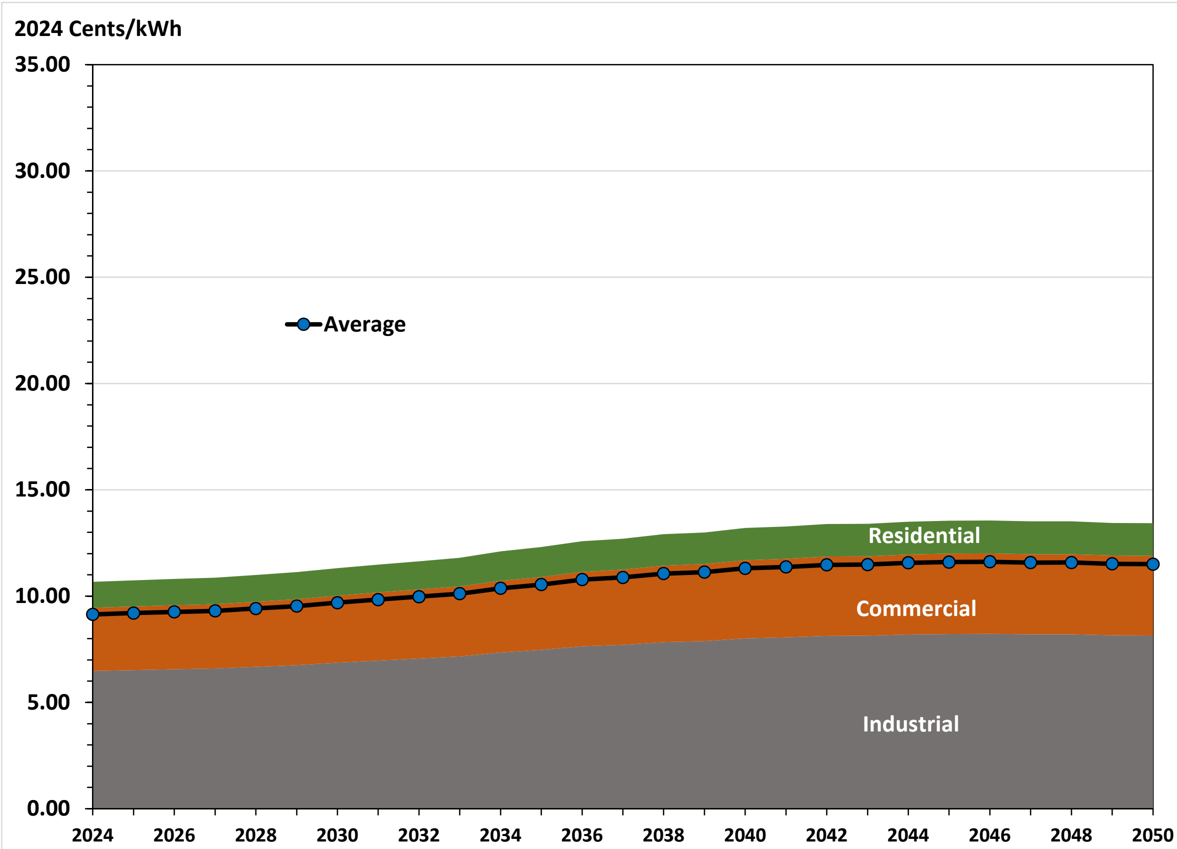
Figure 16: RO Scenario – Projected Retail Electric Rates, 2024 – 2050



Source: authors' calculations.

The NGN Scenario, on the other hand, offers a much more benign energy future. Rates under the NGN Scenario would increase far less (**Figure 17**), rising to an average of 13.6 cents/kWh in inflation-adjusted terms by 2046, less than half the rate increase under the RO Scenario.

Figure 16: NGN Scenario – Projected Retail Electric Rates, 2024 – 2050



Source: authors' calculations.

FULL ELECTRIFICATION WILL HAVE A NEGLIGIBLE IMPACT ON CLIMATE

When Washington Governor Jay Inslee signed CETA into law in 2019, proponents claimed that "Washington is driving forward new ways to confront climate change."[74] The reality is that CETA and Oregon's clean energy legislation will have no measurable impact on world climate. Using the MAGICC climate model that the EPA sponsors,[75] and assuming both states' energy-related carbon emissions were eliminated by 2040, the reduction in world temperature in the year 2100 would be 0.0029 ^{o}C, that is, less than three one-thousandths of a degree centigrade. Such a reduction in global temperature is far too small to be measurable. By comparison, the best outside thermometers have an accuracy of about +/– 0.5 ^{o}C, about 170 times larger.

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[74] Washington Governor's Office, "Washington powers a new path toward clean energy future," Medium, May 7, 2019.

[75] This is based on a comparison with the MAGICC default scenario.

The two states' combined energy-related greenhouse gas (GHG) emissions totaled about 150 million metric tons in 2019, the most recent year for which data for both states are available.[76] Assuming these emissions were reduced at a constant rate until they were eliminated entirely by 2050, the reduction in GHGs would total about 1.8 billion metric tons. By comparison, in 2023, world carbon emissions were estimated to be just over 35 billion metric tons.[77] Thus, even if the 100% electrification efforts eliminate *all* energy-related GHG emissions in the two states, the entire reduction in GHGs between 2024 and 2050 would amount to *less than three weeks* of 2023 world emissions. Under the RO Scenario, the average cost to achieve these reductions in carbon emissions would be over $300 per metric ton. Under the RO Low-Cost scenario, the cost would average about $250 per metric ton.

The net result will be that Oregon and Washington consumers will see their electric rates more than double in inflation-adjusted terms and pay hundreds of billions of dollars to achieve emissions reductions that will have no measurable impact on world climate. By contrast, the impacts on the economic well-being of those individuals and businesses would be only too real.

CONCLUSIONS AND RECOMMENDATIONS

European experience, especially in Germany and Great Britain, has already shown how rising electricity prices have devastating economic impacts. Electric price increases have led to deindustrialization as energy-intensive industries have either contracted or left Europe entirely.[78] Soaring electricity rates also have exacerbated energy poverty, especially in Great Britain.[79]

The results of this study demonstrate that Oregon and Washington's efforts to achieve a zero-emissions energy future by electrifying their economies and relying almost entirely on additional wind and solar power to supply the electricity needed will impose huge costs on individuals and businesses. At the same time, the emissions reductions will be so minuscule that the efforts will provide no measurable climate benefits. Instead, the zero-emissions efforts will be a recipe for economic disaster. The two states would be best served by abandoning these goals, focusing instead on providing reliable and far less costly electricity from new natural gas and nuclear plants.

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76 Washington State Dept. of Ecology, Washington State Greenhouse Gas Emissions Inventory: 1990–2019, December 2022; Oregon Dept. of Environmental Quality, Oregon Greenhouse Gas Sector-Based Inventory, 2022.

77 Energy Institute, 2024 Statistical Review of World Energy, p. 16.

78 Tilak Doshi, "As Europe Deindustrializes, Can Economic Suicide be Avoided?" Forbes, May 9, 2024.

79 Suzanna Hinson and Paul Bolton, "Fuel Poverty," House of Commons Library, February 19, 2024.

APPENDIX: MODELING METHODOLOGY

We use the Always-On Energy Research (AOER) model, which contains two sub-models.

The first sub-model is the reliability model, which uses historical hourly electricity demand and capacity factors for wind and solar to determine the cost-effective buildout of wind, solar, and storage resources necessary to meet demand without thermal resources. New wind and solar resources are built according to capacity values and to satisfy necessary reserve margins to maintain reliability. The model then balances the load by filling any remaining generation shortfalls with 4-hour battery storage facilities. Data sources include the Energy Information Administration (EIA) for hourly electricity load shapes and capacity factors for wind and solar, Avista data for EV charging consumption and load shapes, and PNUCC data for heat pump load patterns.

The second sub-model is the cost model. This model determines the revenue requirements for building and operating the new portfolio of energy sources, determined by the reliability model, compared to today's cost. It utilizes historical cost data from Federal Energy Regulatory Commission (FERC) Form 1 filings and cost assumptions from the Energy Information Administration (EIA) for future builds. Transmission costs are assessed using documents from the National Renewable Energy Laboratory (NREL) that show transmission buildouts needed for certain penetrations of intermittent energy sources like wind and solar and cost estimates of transmission lines from the Midcontinent Independent System Operator (MISO).

Capital Structure: This report utilizes the capital structure of Puget Sound in Washington of 49 percent equity and 51 percent debt, and a return on equity of 9.4 percent. The capital structures for other electric utilities in the two states are similar.

Real Discount Rate: The real discount rate is 3 percent.

Subsidies: This report assumes both wind and solar use the Production Tax Credit (PTC).

Load balancing costs: We calculate load balancing costs by determining the total cost of building and operating new storage facilities to meet electricity demand during the time horizon studied. These costs are then attributed to the system costs of wind and solar by dividing the cost of load balancing by the generation of new wind and solar facilities (capacity-weighted).

Overbuilding and curtailment costs: Overbuilding and curtailment costs measure the cost of overbuilding wind and solar, which results in curtailing more of their energy, lowering their effective capacity factor, and spreading their costs over fewer megawatt-hours (MWh).

Cost of Existing Resources: This report uses cost data from the utility company form 1 filings at the Federal Energy Regulatory Commission (FERC) for capital costs, operation and maintenance costs, and fuel costs.

Cost of New Resources: This report uses cost information from the assumptions of the Annual Energy Outlook Electricity Market Module by the Energy Information Administration (EIA). For new pumped storage, this report uses cost estimates from PacifiCorp.

Unit Lifespans: This report assumes a 20-year lifespan for wind turbines, a 25-year lifespan for solar panels and inverters, and a 15-year lifespan for battery storage facilities before they are repowered.

Transmission: Transmission costs required for the buildout of wind and solar were based on the per-M cost for the buildout of wind and solar for Bonneville Power Administration (BPA).

Hourly Load Shape: This report uses data from the electric grid monitor provided by the Energy Information Administration (EIA) for historical electricity usage. Hourly demand for electric vehicle (EV) electrification was projected by utilizing data by Avista and extrapolating for the states of Washington and Oregon. Hourly demand for home heating electrification was estimated using data provided by PNUCC and extrapolated for the rest of Washington and Oregon using historical temperatures.

Wind and Solar Output: This report uses historical wind and solar output data from the electric grid monitor by the Energy Information Administration (EIA). Wind output is taken from data published by Puget Sound Energy, and solar output is from PacfiCorp.

ABOUT THE AUTHORS

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