Projected Rate Impacts for Utility Customers under HB 3221, the Oregon Renewable Options Program

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SUMMARY

The Oregon Water Resources Congress (OWRC), a nonprofit trade association that represents irrigation districts, water control districts, drainage districts, water improvement districts and other agricultural water providers across the state of Oregon, contracted with Farmers Conservation Alliance (FCA) to produce this report, assessing the potential impacts to investor-owned utility ratepayers if HB 3221 were to be adopted. While every effort was made to consider existing state and federal policies that could impact power rates for utility customers, additional unforeseen factors could apply. If the program were implemented, actual rate impacts could differ, would be dependent on project procurement processes, and would be determined by the Oregon Public Utility Commission (OPUC).[1]

HB 3221, the Oregon Renewable Options (ORO) Program, would create a new, voluntary way for local and tribal governments and local service districts to make decisions regarding the energy sources that power and can provide resilience for the residents and businesses in their communities. If enacted, the program would enable communities in investor-owned electric utility service territories to work with their existing utility in determining the amount of renewable energy in their electricity mix. Participating communities would be required to source at least 5% of their electricity from small, local projects with the capability of providing backup power for energy resilience.

As introduced in HB 3221, the ORO Program would establish processes to ensure that the voices and needs of energy-burdened, disadvantaged and climate vulnerable community members are explicitly considered and incorporated into community energy and resilience planning processes. Pending potential action around differential rate structures by the OPUC, communities could also take additional measures to protect energy burdened customers from any potential cost increases, if they were expected to occur.

There could be significant variation and cost impacts to customers based on how different communities structure local ORO Program implementations. Some communities may simply want to be supplied with enough renewable electricity to meet annual use. Other communities may want to attempt to offset energy use at the time it occurs, a significantly more complex, and

[1] The OPUC is responsible for rate regulation of Oregon's investor-owned electric utilities, natural gas utilities, landline telephone service providers, and select water companies.

likely more expensive, proposition. These differences, which can only be speculated upon at this time, could have very different impacts to customer rates.

The complexity of customer rate structures and a lack of publicly available utility data, limit this report's ability make specific estimates about customer rate impacts. However, it is possible to assess how a more simplified ORO Program structure, assuming renewable electricity is procured just to meet overall annual use, could generally impact customer rates given the difference in energy supply costs between renewable energy facilities and fossil fueled generators.

An initial analysis, using data to represent communities in Portland General Electric and Pacific Power's Oregon service territories, indicates that moving to 100% renewable energy under the ORO Program, including 5% or 5 megawatts (whichever is smaller) of electricity being delivered by small, local projects, appears to create the potential to reduce community members' electricity bills. The lower cost of electricity from utility-scale renewable energy projects drives these potential savings. Small, local projects are assumed to require higher power purchase rates to be financially viable than utility-scale projects.

This analysis further indicates that if communities are interested in investing in more significant amounts of small, local renewable energy projects (e.g., up to 20% of the electricity supply), residential customers could see cost savings, but commercial and industrial customers could be more likely to experience cost-neutral impacts or small cost increases. This result has implications for overall rate designs as well as for potential limits on investments in small scale projects.

Due to the assumptions required to be made in this analysis, communities interested in participating in the ORO Program should not assume that cost savings would occur. Rather, the findings of this report indicate that for some implementation scenarios, overall customer rate changes might be negligible, with the potential for slight cost savings, neutral impacts, or slight cost increases.

Anecdotal evidence from Oregon's Direct Access and Voluntary Renewable Energy Tariff programs, as well as the experience of California's electricity consumers using Community Choice Aggregation programs, also suggests that slight cost savings or minimal cost increases are possible while switching energy supplies to higher portions of renewable electricity.

Important to OWRC's goals, based on the findings in this report, FCA believes that if HB 3221 were adopted it could increase the abilities of agricultural water suppliers to install renewable energy facilities that could support broader irrigation modernization goals. Table 1, below, summarizes the results of the study across three hypothetical Oregon communities.

Table 1. Summary of case study results

Case Study	**A**	**B**	**C**
Example Community	Medium Oregon town (population of ~90,000	Small Oregon town (population of ~10,000),	Large Oregon County (population of ~800,000)
Utility Territory	Pacific Power	Pacific Power	Mixed Pacific Power and Portland General Electric
ORO Application	Converting to 100% renewable energy, including 5% small, local renewable energy projects	Converting to 100% renewable energy, including 20% small local renewable energy projects	Converting to 100% renewable energy, including 20% small local renewable energy projects
Current Power Mix	• 77% carbon-based • 23% renewable	• 77% carbon-based • 23% renewable	Pacific Power • 77% carbon-based • 23% renewable Portland General Electric • 58% carbon-based • 42% renewable
ORO Application Power Mix	• 23% renewable retained • 36% new utility-scale wind • 36% new utility-scale solar • 5% small, local, renewable energy	• 23% renewable retained • 28.5% new utility scale wind • 28.5% new utility scale solar • 20% small, local renewable energy	• Renewable energy from both utilities retained • 5% small, local renewable energy • Remaining carbon-based energy replaced with 50% new utility scale solar and 50% new utility scale wind.
Impact	**Cost savings across all customer classes** compared to current power mix. For example, residential customers save $19/month on electricity.	**A mix of cost savings, cost increases and neutral impacts**. Electricity savings of $9 per month for residential customers, cost increases of $11 per month for commercial customers, and no change for industrial customers. Cost savings reappear across all customer classes if small projects are reduced to 14% of the electricity supply.	**Cost savings across all customer classes** compared to current power mix.

INTRODUCTION

In recent years, a number of Oregon's municipal and county governments have adopted policies that encourage broader use or adoption of renewable energy projects, often at community-wide scale. Examples include the cities of Bend,[2] Milwaukie,[3] and Portland,[4] as well as Hood River[5] and Multnomah[6] counties. At present, these communities served by Oregon's investor-owned utilities do not have a transparent pathway for working with their electricity supplier to meet their policy goals.

Oregon's investor-owned utilities are responsible for meeting the renewable energy policy goals set within the state's Renewable Portfolio Standard (RPS), which they typically demonstrate by installing or purchasing the output of large-scale wind and solar resources. Oregon's RPS requires that 50% of the electricity that Oregonians use come from renewable resources by 2040.[7] In late 2020, Portland General Electric announced plans to significantly accelerate renewable energy adoption beyond the statutory requirements of the RPS.[8] Similarly, Pacific Power's "Energy Vision 2020" plan[9] goes beyond the requirements of Oregon's RPS.

Oregon energy policies also support the installation of smaller scale, local renewable energy projects: net energy metering, the Community Solar Program, or wholesale electricity sales under a power purchase agreement. Net energy metering allows a generation facility to offset on-site energy use at the customer's retail electricity rate, up to certain project sizes. Rooftop solar is typically net energy metered. The Community Solar Program is a virtual net energy metering option, offsetting retail rates, but is only available for solar photovoltaic projects in investor-owned utility territory. Electricity sales under a power purchase agreement are available to all local renewable energy projects, up to certain sizes, through the OPUC's implementation of the Public Utility Regulatory Policy Act of 1978 (PURPA). Power purchase agreements under PURPA are at wholesale rates. In the last decade, wholesale electricity rates have dropped significantly making it hard for local renewable energy projects to achieve financial viability.

The Oregon Water Resources Congress (OWRC), a nonprofit trade association that represents irrigation districts, water control districts, drainage districts, water improvement districts and other agricultural water providers across the state of Oregon, contracted with Farmers

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[2] Community Climate Action Plan. https://www.bendoregon.gov/city-projects/sustainability/community-climate-action-plan
[3] Climate Action. https://www.milwaukieoregon.gov/sustainability/climateaction
[4] Establish goal to transition Portland to 100% renewable energy by 2050 resolution. (2017). https://efiles.portlandoregon.gov/Record/11004056/
[5] Hood River County Energy Plan. (2018). https://www.mcedd.org/wp-content/uploads/2019/04/Hood-River-Energy-Plan_6-18-18.pdf
[6] 100% Renewable by 2050. https://multco.us/sustainability/100-renewable-2050
[7] Oregon Renewable Portfolio Standard. https://www.oregon.gov/energy/energy-oregon/Pages/Renewable-Portfolio-Standard.aspx
[8] Portland General Electric aims for companywide net zero greenhouse gas emissions by 2040. (2020). Portland General Electric. https://portlandgeneral.com/news/2020-11-18-portland-general-electric-aims-for-companywide-net-zero
[9] Energy Vision 2020. Pacific Power. https://www.pacificpower.net/about/innovation-environment/energy-vision-2020.html

Conservation Alliance (FCA) to produce this report, assessing the potential impacts to investor-owned utility ratepayers if HB 3221 were to be adopted.

HB 3221 would create a community-wide green tariff program, a voluntary way for local and tribal governments and local service districts to make decisions regarding the energy sources that power and can provide resilience for the residents and businesses in their communities. If enacted, the bill would authorize the Oregon Renewable Options (ORO) Program, enabling communities in investor-owned electric utility service territories to work with their existing utility in determining the amount of renewable energy in their electricity mix. Participating communities would be required to source at least 5% or 5 megawatts (whichever is smaller) of their electricity from small, local projects with the capability of providing backup power for energy resilience.

HB 3221 could present a bridge between communities that wish to take action on renewable energy goals and the investor-owned utilities' plans to move beyond RPS requirements. It would also create a path for broader adoption of local renewable energy projects, which may be able to provide additional benefits beyond energy generation.

It is important to consider the potential for HB 3221 to cause changes to the rates of investor-owned electric utility customers. As introduced in HB 3221, the ORO Program would establish processes to ensure that the voices and needs of energy-burdened, disadvantaged and climate vulnerable community members are explicitly considered and incorporated into community energy and resilience planning processes. Pending potential action around differential rate structures by the OPUC, communities could also take additional measures to protect energy-burdened customers from any potential cost increases, if they were expected to occur.

This report was authored by staff and contractors of Farmers Conservation Alliance (FCA). FCA is a 501(c)3 non-profit that works with irrigation districts and other agricultural water suppliers to design and implement optimized water delivery systems. One example of modernizing agricultural water delivery infrastructure would be piping and pressurizing formerly open canals. Modernizing irrigation infrastructure can improve water supply reliability (and therefore food production), keep contaminants out of agricultural water supplies, prevent fish from being trapped in canals, and reduce the energy required to pump water across the landscape. These same infrastructure changes also allow for more and cleaner water in streams and rivers, help fish access high-quality habitat, foster the creation of pollinator corridors along newly-buried pipelines, and generate fish-friendly, conduit hydropower with water already being diverted for farms and ranches.

Conduit hydropower projects can provide energy resilience and other benefits for rural communities. Projects between 1-5 megawatts of capacity may be capable of energizing all or portions of utility circuits, keeping critical facilities such as hospitals and fire stations energized during outages, Public Safety Power Shutoff (PSPS) events to prevent wildfires, or other grid disturbances. Similar benefits are possible through other renewable technologies, such as the combination of solar photovoltaics and battery storage to create local microgrids.

FCA's services include assisting the development of renewable energy installations in conjunction with irrigation modernization activities, where revenues from long-term electricity sales can support broader modernization project implementation.

To be financially viable, a renewable energy project's revenues must be sufficient to cover its installation expenses and long-term operation and maintenance costs. Projects that provide additional benefits beyond electricity generation (e.g., local energy resilience, jobs, or environmental improvements) may have correspondingly higher installation costs or project revenues may be expected to pay for other long-term costs not directly related to the energy facility, such as servicing debt on the installation of a pipeline.

Conduit hydropower projects are typically only able to sell their electricity through PURPA power purchase agreements because they are not often co-located where significant electricity use occurs or they exceed net energy metering size limits. In addition, hydropower is not eligible under the Community Solar Program. As a result of the low wholesale energy prices available, very few conduit hydropower projects were installed in Oregon in the last decade, stifling these facilities' ability to support broader irrigation modernization goals.

This report examines the potential rate impacts to the customers of investor-owned electric utilities under ORO Program participation scenarios in hypothetical Oregon communities. The report is broken into sections exploring the assumptions which underly the analysis, the methods used to conduct the analysis, a description of the results seen, and a discussion of the implications of the results.

ASSUMPTIONS

Utility rate structures are complex and vary across customer classes (e.g., residential, commercial, industrial). Most customer costs, though, can generally be accounted for in two categories: costs associated with energy *supply* (production costs) and costs associated with energy *delivery* (transmission and distribution costs). To calculate the hypothetical rate impacts of the ORO Program to utility customers in different scenarios, the analysis examines potential changes in cost related to energy *supply*.

This analysis assumes that the ORO Program does not affect energy *delivery* costs. Upgrades to utility transmission and distribution systems are often needed over time in various locations. Many of the associated upgrade costs would be incurred with or without the ORO Program. To the extent that a specific renewable energy procurement or installation requires grid upgrades to deliver power, those costs are typically born by the individual project during interconnection processes and are not typically reflected in supply costs. Thus, energy *delivery* costs are not expected to change under the ORO Program but do need to be calculated and understood as a portion of total customer costs.

Energy *supply* costs can be further differentiated into *fixed* costs and *variable* costs. The cost of building a new power plant can be thought of a *fixed* cost, while the operating labor and fuel (for a fossil fired power plant) can be understood as *variable* costs. Utilities account for these fixed and variable costs in different ways within their rate schedules. For example, all customers pay a "basic charge." This basic charge varies by customer class and is used to assess a fee, at least in part, for some a utility's fixed costs. Both Pacific Power and Portland General Electric also have rate schedules that change annually to account for variable costs in energy supply.

To think about how energy *supply* costs could change if the ORO Program were implemented, consider the following simplified example: if energy use is held constant but a utility switches production from coal to solar, there should be, at a minimum, a corresponding reduction in variable operational costs to the utility from avoided fuel purchases for the coal-fired power plant. As the costs of utility scale wind and solar have dropped, these sources have become more cost effective than coal-fired generation.[10] Correspondingly, utilities have accelerated the closure of coal-fired power plants across the country. Cost savings from power plants that do not require purchased fuel can, where determined appropriate by regulators, be passed on to customers in electricity rates. These potential savings to a utility's variable costs are a critical assumption in this analysis. The analysis also assumes that existing renewable energy projects already serving customer loads would be retained as part of a utility's fixed energy supply costs.

It is important to recognize that there are interactive effects and significant complexity in thinking about a utility's fixed and variable energy supply costs as additional renewable energy projects are brought into the electrical system. If, for example, under the ORO Program a utility procured a significant amount of new renewable solar and wind projects, the energy and capacity from those resources could defer planned purchases of energy or capacity to meet utility resource adequacy requirements. This could result in neutral or downward price pressure on the fixed costs assessed to all of the utility's customers. For several reasons, it is not possible, within this report, to assess the specific potential rate impacts associated with these kinds of changes:

A. There could be significant variation and cost impacts between how different communities structure local ORO Program implementations. Some communities may want to simply be supplied with enough renewable electricity to meet annual use. Other communities may want to attempt to offset energy use at the time it occurs, a significantly more complex, and likely more expensive, proposition. These differences, which can only be speculated upon at this time, could have very different impacts to the short-term and long-term fixed and variable energy supply costs of a utility.
B. FCA lacks access to the data and the specialized expertise required to perform this kind of complex utility rate impact analysis. Much of the data that would be required to perform in-depth scenario analyses with this level of complexity is only available to the utilities or the OPUC.

These complexities and the unavailability of the necessary data, limit this report's ability make *specific* estimates about electric customer rate impacts under ORO Program implementation scenarios. However, it is possible to assess how some ORO Program structures could *generally* impact customer rates given the difference in variable energy supply costs between renewable energy facilities and fossil fueled generators.

In general, this methodology – assessing the changes in costs related to electricity supply while holding delivery costs constant – is consistent with the way in which customers are billed under

[10] Renewable Electricity Levelized Cost Of Energy Already Cheaper Than Fossil Fuels, And Prices Keep Plunging. (2018). *Energy Innovation Policy and Technology LLC*. https://energyinnovation.org/2018/01/22/renewable-energy-levelized-cost-of-energy-already-cheaper-than-fossil-fuels-and-prices-keep-plunging/

Oregon's Direct Access and Voluntary Renewable Energy Tariff (VRET) programs. Customers that elect to use Direct Access get energy from an Electricity Service Supplier (ESS) but the electricity is delivered by an investor owned utility. Direct access customers pay for electricity delivery costs like other customers but may be able to achieve cost savings on the energy supplied by the ESS.

Under the VRET, investor-owned utility customers enter into a power purchase agreement with their utility related to a new renewable energy facility. The customer's typical energy supply and delivery costs remain the same, on top of the additional power purchase agreement rate, but an additional credit is applied to the customer's bill related to the value of the energy and capacity of the facility to the utility. Anecdotally, this has resulted in relatively minimal cost increases to VRET customers while dramatically increasing the amount of renewable energy they are supplied.

Finally, this analysis does not explore the potential for existing utility owned power plants to become "stranded assets" or to calculate the potential associated costs that might need to be passed on to customers. Stranded assets are pieces of utility-owned infrastructure that are unable, due to changes in regulations, to produce the long-term value and return on investment expected when they were purchased.

Stranded assets can, however, be considered through the lens of states that have adopted Community Choice Aggregation (CCA) policy models. The US Environmental Protection Agency notes that CCAs "allow local governments to procure power on behalf of their residents, businesses, and municipal accounts from an alternative supplier while still receiving transmission and distribution service from their existing utility provider."[11] In California, CCA's led to many customers leaving their incumbent utility, and some utility-owned power plants were found to be stranded assets by the California Public Utilities Commission. These stranded asset costs were managed through "Power Charge Indifference Adjustments."[12] While fully capturing these stranded asset costs, California's CCA customers have been able to purchase 100% renewable energy at rates that vary from slightly less to several percent more than their original utility rate, depending on the chosen option.[13]

Importantly, the ORO Program is *not* a CCA model and *under the ORO program consumers remain with their existing utility*. To the extent that stranded assets are or become a concern based on an ORO Program implementation, the OPUC has experience assessing and managing stranded assets costs, and the existing methodologies used within the context of Oregon's RPS could also be considered for use with the ORO Program.

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[11] What is Community Choice Aggregation (CCA)? (2021). United States Environmental Protection Agency. https://www.epa.gov/greenpower/community-choice-aggregation

[12] Brooks, D. (2020). Power to the People: Community Choice Aggregation in California. *Georgetown Environmental Law Review.* https://www.law.georgetown.edu/environmental-law-review/blog/power-to-the-people-community-choice-aggregation-in-california/

[13] See comparison of rates from Pacific Gas and Electric and Marin Clean Energy: https://www.pge.com/pge_global/common/pdfs/customer-service/other-services/alternative-energy-providers/community-choice-aggregation/mce_rateclasscomparison.pdf

METHODOLOGY

The methods used for determining electricity supply and delivery costs are explained in greater detail below. A Microsoft Excel workbook containing the calculations associated with this analysis accompanies this report.

Baseline Energy Supply Cost Analysis

For Oregon's investor-owned electric utility customers, rates are determined through OPUC regulatory processes and published in "rate schedules" on each utility's website. To determine potential rate changes customers could see under hypothetical ORO Program scenarios, it is first necessary to understand baseline energy supply costs.

For Pacific Power customers, baseline energy supply costs were determined by adding together Schedule 200 and Schedule 201 costs from the appropriate customer class rate schedules[14] (e.g. Schedule 4 for residential customers, the average of Schedules 23, 28, and 30 for commercial customers), and the average of Schedules 47 and 48 (60% on peak and 40% off peak) for industrial customers (Table 2).

Table 2. Pacific Power baseline energy supply costs

Customer class	Schedule 200 costs ($/kWh)	Schedule 201 costs ($/kWh)	Total cost ($/kWh)
Residential - Schedule 4	$0.030	$0.029	$0.059
Commercial - Average of Schedules 23, 28, 30	$0.020	$0.021	$0.041
Industrial - Schedules 47/48 (averaged 60% on peak / 40% off peak)	$0.021	$0.023	$0.044

The same methodology was used to determine baseline energy supply costs for Portland General Electric customers[15] (Table 3). Rate schedules and the ways they were averaged for each customer class are indicated in the body of Table 3.

[14] All referenced Pacific Power rate schedules are available here: https://www.pacificpower.net/about/rates-regulation/oregon-rates-tariffs.html
[15] All referenced Portland General Electric rate schedules are available here: https://portlandgeneral.com/about/rates-and-regulatory/tariff

Table 3. Portland General Electric baseline energy supply costs

Rate schedule, costs in $/kWh	Average of rate schedule(s) noted ($/kWh)	Schedule 125 Adjustment ($/kWh)	Total cost ($/kWh)
Residential - Schedule 7	$0.063	$0.006	$0.069
Commercial - Average of Schedules 32, 83, 85, averaged 60% on peak, 40% off peak where applicable	$0.057	$0.005	$0.062
Industrial - Average of Schedules 89, 90, averaged 60% on peak / 40% off peak	$0.050	$0.005	$0.055

Baseline Energy Delivery Cost Analysis

With the exception of residential customers, energy delivery costs cannot be easily extracted from either utility's rate schedules because of differences in capacity and base charges that vary between and within the utilities by customer class. To create a uniform method of estimating delivery costs (as shown in Table 4 and Table 5) the calculated baseline energy supply costs (Table 2, Table 3) were subtracted from Oregon's average price of electricity to the consumer. Oregon's average price of electricity data came from the United States Energy Information Administration (EIA).[16]

Table 4. Pacific Power energy delivery costs

Customer class	Average price of electricity to ultimate customer	Calculated baseline energy supply costs	Calculated cost of delivery service
Residential	$0.111	$0.059	$0.052
Commercial	$0.090	$0.041	$0.049
Industrial	$0.062	$0.044	$0.018

Table 5. Portland General Electric energy delivery costs

Customer class	Average price of electricity to ultimate customer	Calculated baseline energy supply costs	Calculated cost of delivery service
Residential	$0.111	$0.069	$0.042
Commercial	$0.090	$0.062	$0.028
Industrial	$0.062	$0.055	$0.007

[16] Oregon State Energy Profile. (2020). US Energy Information Administration. https://www.eia.gov/state/print.php?sid=OR

As noted above, delivery costs for residential customers are specified in each utility's respective rate schedule. Pacific Power's residential delivery rate in Schedule 4 sums to $0.045/kWh while Portland General Electric's residential delivery rate in Schedule 7 sums to $0.049/kWh. By comparison, the calculated delivery cost is $0.007 higher for Pacific Power and $0.007 lower for Portland General Electric, a difference of approximately 15% for each utility. This suggests the calculated delivery costs, while certainly not perfect, are in the ballpark of the actual value for residential customers.

The rate schedules for customers participating in Direct Access programs, where energy is provided by an ESS and the investor-owned utility provides energy delivery, were investigated to determine if delivery rates could be extracted for commercial or industrial customers. Unfortunately, as with the standard commercial and industrial rate schedules, a large portion of the delivery costs are calculated based on the capacity requirements (kW) of the individual customer and only a small portion of the delivery cost is based on the amount of electricity delivered (kWh). As such, it is not possible to cross check the calculated energy delivery costs for commercial or industrial customers. This creates an unknown amount of potential error in the analysis.

Energy Resource Mix

The current resource mix for each utility informs how much energy might need to be procured by a community wishing to move to 100% renewable electricity sources.

For Pacific Power, resource mix data were extracted from the utility's published 2018 resource mix for Oregon (Table 6).[17] More up-to-date data were not able to be found. This data may under-represent the amount of renewable energy in the utility's current power mix as RPS requirements have increased over time. Based on the 2018 data, Pacific Power's resource mix was approximately 77% fossil-based[18] and approximately 23% greenhouse gas emissions-free.

Table 6. Pacific Power 2018 Oregon Resource Mix

Technology	Owned resources and market purchases	Unspecified market purchases	Total
Coal	56.25%	2.51%	58.76%
Natural Gas	15.40%	2.27%	17.67%
Hydro	5.13%	4.20%	9.33%
Wind	9.00%	0.00%	9.00%
Solar	3.82%	0.00%	3.82%
Biomass	0.34%	0.22%	0.56%
Geothermal	0.34%	0.00%	0.34%

[17] Your Power Sources. (2018) Pacific Power. Page 2. https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/my-account/bill-inserts/OR%20Labeling%20Insert%20Large%20Business.pdf

[18] It is not known of "Other" resources, which make up 0.29% of the utility's resource mix, come from fossil or other carbon-producing sources. In addition, not all stakeholders consider biomass to be a "renewable" or carbon-free resource.

Other	0.17%	0.12%	0.29%
Nuclear	0.00%	0.22%	0.22%
Biogas	0.00%	0.00%	0.00%
Total	90.45%	9.54%	99.99%

For Portland General Electric, resource mix data were available for 2019 from the utility's annual report to investors (Table 7).[19] As in the case of Pacific Power, the data available may understate Portland General Electric's current renewable energy resource mix as the company recently closed its Boardman coal-fired power plant and made other resources changes to compensate. Based on the data available, this analysis assumed that Portland General Electric's resource mix was approximately 58.5% fossil based[20] and approximately 41.5% greenhouse gas emissions-free.

Table 7. Portland General Electric 2019 Oregon Resource Mix

Technology	**Owned resources and market purchases**
Natural Gas	35.0%
Hydro	18.0%
Wind	16.0%
Coal	15.0%
Short term contracts (STC)	9.0%
PURPA Qualifying Facilities	3.0%
Dispatchable standby generation (DSG)	2.0%
Capacity	2.0%
Solar	0.0%
Total	100.0%

Fossil Fuel and Renewable Energy Resource Costs

Next the analysis compared the baseline energy supply costs to cost data for fossil-fired power plants, cost data for new utility-scale solar and wind installations, and estimated cost requirements for small-scale, local renewable energy projects.

It was not possible to find published data from either utility regarding the costs of energy from their fossil-fired power plants. The EIA, however, publishes energy cost data across a variety of generation technologies. As a proxy, this analysis looked at EIA's published "levelized avoided

[19] Portland General Electric 2019 Annual Report. (2020). Page 12. https://investors.portlandgeneral.com/static-files/f6dba6a9-163c-4de2-b6fc-cac6adfa7693
[20] This assumes that all Dispatchable Standby Generation and Capacity projects are fossil based and that approximately 50% of the company's short term contracts are fossil based. The Oregon Department of Energy's Electricity Mix in Oregon website indicates that approximately 50% of market purchases in Oregon are fossil based. See "Market Purchases" tab: https://www.oregon.gov/energy/energy-oregon/pages/electricity-mix-in-oregon.aspx

cost of electricity for new resources."[21] Avoided costs are commonly used as a proxy for the costs a utility would incur if it purchased or generated energy itself, rather than purchasing it from another source. As EIA's data specifically looks at new, high-efficiency resources, it may not be a perfect proxy for older equipment. The data does, however, provide a ballpark reference for costs.

Both Pacific Power and Portland General Electric publish their own avoided cost rates for new renewable energy resources, which developers of "qualifying facility" solar and wind projects up to 10 megawatts in capacity can secure without needing to negotiate with the utility.

Pacific Power publishes renewable energy avoided costs as annual on-peak and off-peak rates for a 20-year time period. The energy rates change each year. For this analysis, an average cost is easier to work with for comparative purposes. To create this comparative cost, avoided cost rates for wind projects[22] were evaluated as 50% on-peak and 50% off-peak and annual rates were averaged over a 20-year period. The same calculation was performed for Pacific Power's tracking solar avoided cost rates[23], except that energy generation was assumed to be 86% on-peak and 14% off-peak.[24]

Portland General Electric's Schedule 201[25] provides similar avoided cost rates as Pacific Power, but further differentiates rates on a monthly basis. To create a comparative cost, the analysis weighted solar energy production by month across the year as well as by on-peak and off-peak times. As with Pacific Power, wind production was assumed to be 50% on-peak and 50% off-peak over the year.

To estimate the rates that might be needed for smaller-scale projects, six irrigation district managers that own local, small hydropower projects were consulted about the electricity pricing needed to operate their systems while providing community benefits beyond renewable electricity. The consensus of the group of managers surveyed was that at $0.08 per kilowatt hour, their projects would provide enough revenue for the district to re-invest in irrigation system modernization projects that can provide significant energy, environmental, agricultural, and economic benefits in their regions. Different types of small-scale renewable energy technologies, such as solar, could have other cost requirements that were not assessed in this study.

As can be seen in Table 8, below, Pacific Power's avoided costs, which are used here to represent utility scale renewable energy projects, appear to offer a significant discount compared to the fossil fueled power plants. Portland General Electric's avoided costs are higher. However, the

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[21] Levelized Costs of New Generation Resources in the *Annual Energy Outlook 2021*. (2021). US Energy Information Administration. Table 3, page 10. https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf
[22] Page 8. https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/purpa/Standard_Avoided_Cost_Rates_Avoided_Cost_Purchases_From_Eligible_Qualifying_Facilities.pdf
[23] Page 9. https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/purpa/Standard_Avoided_Cost_Rates_Avoided_Cost_Purchases_From_Eligible_Qualifying_Facilities.pdf
[24] On-peak energy times are defined as 6am-10pm Monday through Saturday, Sunday is off-peak.
[25]https://assets.ctfassets.net/416ywc1laqmd/tFuVXUn8D61vu8WrziC9p/0b8fa21e86d5df5639df2540e68e6c20/business-sched-201.pdf

avoided costs for both utilities are still below the calculated energy supply rates shown in Table 2 and Table 3.

Table 8. Comparison of resource costs on a per kilowatt hour basis

Technology	**Price per kilowatt hour**	**Data source**
Coal	$0.040	US EIA Levelized Avoided Cost
Natural Gas	$0.045	US EIA Levelized Avoided Cost
Solar – PAC	$0.029	Pacific Power Avoided Cost
Wind – PAC	$0.035	Pacific Power Avoided Cost
Solar – PGE	$0.054	Portland General Electric Avoided Cost
Wind – PGE	$0.050	Portland General Electric Avoided Cost
Local projects	$0.080	Irrigation district manager survey

Baseline Cost Calculations for Community Case Studies

To model the potential cost changes that could occur if the ORO program is implemented, representatives from several Oregon municipalities and counties were interviewed to learn about the energy use in their communities. Based on information collected in the interviews, three hypothetical model communities (communities “A”, “B”, and “C”) were created that could represent small or medium cities and a large county interested in participating in the ORO program.

Community A represents a town of approximately 90,000 people and a total electricity consumption of 883 million kWh annually. Residential, commercial, and industrial use account for 49%, 45%, and 6% of the electricity, respectively. Community “A” has approximately 34,000 residential electric energy accounts and unknown numbers of commercial and industrial accounts.

Community B represents a town of 10,000 citizens with total annual electricity consumption of 138 million kWh. Residential, commercial, and industrial use account for 47%, 49%, and 4% of the electricity, respectively. Community “A” has approximately 6,100 residential electric energy accounts, 1,100 commercial accounts, and 16 industrial accounts.

Community C represents a large county of approximately 800,000 residents with energy consumption of just over 2 billion kWh in Pacific Power territory and 5.9 billion kWh in Portland General Electric territory. The relative size of the customer classes varies by service territory and the total number of accounts in each customer class is unknown.

Baseline energy cost calculations were made for each community using the energy supply and energy deliver cost numbers calculated earlier (Table 9, Table 10, Table 11). Where possible, costs were extrapolated down to average annual or average monthly costs per account. Where there was not enough data to do so, only total customer category costs were calculated.

Table 9. Baseline costs for Community A

Community A - PAC Loads	Annual electricity use (kWh)	Current supply cost $/kWh	Current delivery cost $/kWh	Total current cost $/kWh	Total current annual energy cost	Current average annual cost per account	Current average monthly cost per account
Residential	432,000,000	$ 0.059	$ 0.052	$ 0.111	$ 48,038,400	$ 1,412.89	$ 117.74
Commercial	395,000,000	$ 0.041	$ 0.049	$ 0.090	$ 35,708,000	Not possible to calculate without # of commercial and industrial accounts	
Industrial	56,000,000	$ 0.044	$ 0.018	$ 0.062	$ 3,494,400		
Total	883,000,000				$ 87,240,800		

Table 10. Baseline costs for Community B

Community B - PAC Loads	Annual electricity use (kWh)	Current supply cost $/kWh	Current delivery cost $/kWh	Total current cost $/kWh	Total current annual energy cost	Current average annual cost per account	Current average monthly cost per account
Residential	65,000,000	$ 0.059	$ 0.052	$ 0.111	$ 7,228,000	$ 1,184.92	$ 98.74
Commercial	68,000,000	$ 0.041	$ 0.049	$ 0.090	$ 6,147,200	$ 5,588.36	$ 465.70
Industrial	5,000,000	$ 0.044	$ 0.018	$ 0.062	$ 312,000	$ 19,500.00	$ 1,625.00
Total	138,000,000				$ 13,687,200		

Table 11. Baseline costs for Community C

Community C - PAC Loads	Annual electricity use (kWh)	Current supply cost $/kWh	Current delivery cost $/kWh	Total current cost $/kWh	Total current annual energy cost	Current average annual cost per account	Current average monthly cost per account
Residential	580,000,000	$ 0.059	$ 0.052	$ 0.111	$ 64,496,000	Not possible to calculate without number of commercial and industrial accounts	
Commercial	1,160,000,000	$ 0.041	$ 0.049	$ 0.090	$ 104,864,000		
Industrial	273,000,000	$ 0.044	$ 0.018	$ 0.062	$ 17,035,200		
Total	2,013,000,000				$ 186,395,200		

Community C - PGE Loads	Annual electricity use (kWh)	Current supply cost $/kWh	Current delivery cost $/kWh	Total current cost $/kWh	Total current annual energy cost	Current average annual cost per account	Current average monthly cost per account
Residential	2,232,000,000	$ 0.069	$ 0.042	$ 0.111	$ 248,198,400	Not possible to calculate without number of commercial and industrial accounts	
Commercial	2,519,000,000	$ 0.062	$ 0.028	$ 0.090	$ 227,717,600		
Industrial	1,143,000,000	$ 0.055	$ 0.007	$ 0.062	$ 71,323,200		
Total	5,894,000,000				$ 547,239,200		

Renewable Energy Scenarios for Community Case Studies

For each hypothetical community, a scenario was created to test the cost impacts of supplying the community with 100% renewable energy, including portions delivered by small, local projects. The ORO program would require a minimum of the lesser of 5% or 5 megawatts of a community's energy be served by small projects.

For Community A, the following scenario was analyzed. Rate implications are shown in Table 12.

- 23.28% of the electricity was retained as the renewable energy portion of the existing resource mix, at the supply costs calculated in Table 1, above.
- 35.86% of the fossil-based electricity was replaced with tracking solar at a supply cost of $0.029/kWh.
- 35.86% of the fossil-based electricity was replaced with wind at a supply cost of $0.035/kWh.
- 5% of the fossil-based electricity was replaced with small local projects at a supply cost of $0.080/kWh.

For Community B, a different scenario with a greater amount of local energy was analyzed. Rate implications are included in Table 13.

- 23.28% of the electricity was retained as the renewable energy portion of the existing resource mix, at the supply costs calculated in Table 1, above.
- 28.36% of the fossil-based electricity was replaced with tracking solar at a supply cost of $0.029/kWh.
- 28.36% of the fossil-based electricity was replaced with wind at a supply cost of $0.035/kWh.
- 20% of the fossil-based electricity was replaced with small local projects at a supply cost of $0.080/kWh.

For Community C, loads and costs from each utility were analyzed separately. In Pacific Power territory, the same scenario was used as in Community A. Rate implications are included in Table 14.

- 23.28% of the electricity was retained as the renewable energy portion of the existing resource mix, at the supply costs calculated in Table 1, above.
- 35.86% of the fossil-based electricity was replaced with tracking solar at a supply cost of $0.029/kWh.
- 35.86% of the fossil-based electricity was replaced with wind at a supply cost of $0.035/kWh.
- 5% of the fossil-based electricity was replaced with small local projects at a supply cost of $0.080/kWh.

In the portion of Community C served by Portland General Electric, the following scenario was analyzed. Rate implications are included in Table 15.

- 41.5% of the electricity was retained as the renewable energy portion of the existing resource mix, at the supply costs calculated in Table 2, above.
- 26.75% of the fossil-based electricity was replaced with solar at a supply cost of $0.054/kWh.
- 26.75% of the fossil-based electricity was replaced with wind at a supply cost of $0.050/kWh.
- 5% of the fossil-based electricity was replaced with small local projects at a supply cost of $0.080/kWh.

A weighted average supply cost for the existing and new energy sources was then calculated for each customer class. These new weighted average supply costs were then added to the existing delivery costs to determine the total service cost. The total service costs were then multiplied by the customer class loads to determine the differences between current costs with current energy sources and estimated costs with the specified mix of renewable energy sources.

RESULTS

In the modelled hypothetical communities cost savings occur for residential customers in all scenarios. Cost savings occur for commercial customers in the scenarios for Communities A and C but a modest increase occurs at the higher level of small-scale renewables that are analyzed in Community B. Industrial customers see either cost savings or no change in all scenarios. Below, the results in each scenario are looked at in greater detail.

Community A

Cost savings appear to be possible across all customer classes in Community A as an outcome of switching from its current mix of energy sources to 100% renewable energy (Table 12). For example, residential customers save $19/month on electricity.

Table 12. Community A Case Study Results

Community A - Current Energy Supply	Annual electricity use (kWh)	Current supply cost $/kWh	Current delivery cost $/kWh	Total current cost $/kWh	Total current annual energy cost	Current average annual cost per account	Current average monthly cost per account
Residential	432,000,000	$ 0.059	$ 0.052	$ 0.111	$ 48,038,400	$ 1,412.89	$ 117.74
Commercial	395,000,000	$ 0.041	$ 0.049	$ 0.090	$ 35,708,000	Not possible to calculate without # of commercial and industrial accounts	
Industrial	56,000,000	$ 0.044	$ 0.018	$ 0.062	$ 3,494,400		
Total	883,000,000				$ 87,240,800		
Community A - ORO Program Scenario	**Annual electricity use (kWh)**	**ORO supply cost $/kWh**	**Current delivery cost $/kWh**	**Total ORO cost $/kWh**	**Total ORO annual energy cost**	**ORO average annual cost per account**	**ORO average monthly cost per account**
Residential	432,000,000	$ 0.041	$ 0.052	$ 0.093	$ 40,087,879	$ 1,179.06	$ 98.25
Commercial	395,000,000	$ 0.036	$ 0.049	$ 0.086	$ 33,893,219	Not possible to calculate without # of commercial and industrial accounts	
Industrial	56,000,000	$ 0.037	$ 0.018	$ 0.055	$ 3,090,438		
Total	883,000,000				$ 77,071,536		

Community B

The scenario modeled for Community B would yield a mix of cost savings, cost increases and neutral impacts (Table 13). Residential customers would see cost savings of approximately $9/month under this scenario. In contrast with Community A, commercial customers would see a small cost increase (approximately 2.4%, or $11/month). Industrial customers would see almost no difference in energy costs. If the percentage of energy supplied by small-scale renewables in Community B were reduced from 20% to 14%, cost savings would appear across all customer classes.

Table 13. Community B case study results

Community B - Current Energy Supply	Annual electricity use (kWh)	Current supply cost $/kWh	Current delivery cost $/kWh	Total current cost $/kWh	Total current annual energy cost	Current average annual cost per account	Current average monthly cost per account
Residential	65,000,000	$ 0.059	$ 0.052	$ 0.111	$ 7,228,000	$ 1,184.92	$ 98.74
Commercial	68,000,000	$ 0.041	$ 0.049	$ 0.090	$ 6,147,200	$ 5,588.36	$ 465.70
Industrial	5,000,000	$ 0.044	$ 0.018	$ 0.062	$ 312,000	$ 19,500.00	$ 1,625.00
Total	138,000,000				$ 13,687,200		
Community B - ORO Program Scenario	**Annual electricity use (kWh)**	**ORO supply cost $/kWh**	**Current delivery cost $/kWh**	**Total ORO cost $/kWh**	**Total ORO annual energy cost**	**ORO average annual cost per account**	**ORO average monthly cost per account**
Residential	65,000,000	$ 0.048	$ 0.052	$ 0.100	$ 6,550,441	$ 1,073.84	$ 89.49
Commercial	68,000,000	$ 0.044	$ 0.049	$ 0.093	$ 6,297,206	$ 5,724.73	$ 477.06
Industrial	5,000,000	$ 0.044	$ 0.018	$ 0.062	$ 311,986	$ 19,499.10	$ 1,624.92
Total	138,000,000				$ 13,159,632		

Community C

Community C would see cost savings across all customer classes under the scenario modeled (Table 14, Table 15). The magnitude of cost savings is lower in areas served by Portland General Electric due to the utility's higher avoided costs for renewable energy. Industrial customers in Portland General Electric territory see the least savings, slightly less than 1% of total costs.

Table 14. Community C case study results, Pacific Power areas

Community C - PAC Current Energy Supply	Annual electricity use (kWh)	Current supply cost $/kWh	Current delivery cost $/kWh	Total current cost $/kWh	Total current annual energy cost
Residential	580,000,000	$ 0.059	$ 0.052	$ 0.111	$ 64,496,000
Commercial	1,160,000,000	$ 0.041	$ 0.049	$ 0.090	$ 104,864,000
Industrial	273,000,000	$ 0.044	$ 0.018	$ 0.062	$ 17,035,200
Total	2,013,000,000				$ 186,395,200
Community C - PAC ORO Program Scenario	**Annual electricity use (kWh)**	**ORO supply cost $/kWh**	**Current delivery cost $/kWh**	**Total ORO cost $/kWh**	**Total ORO annual energy cost**
Residential	580,000,000	$ 0.041	$ 0.052	$ 0.093	$ 53,821,690
Commercial	1,160,000,000	$ 0.036	$ 0.049	$ 0.086	$ 99,534,515
Industrial	273,000,000	$ 0.037	$ 0.018	$ 0.055	$ 15,065,886
Total	2,013,000,000				$ 168,422,091

Table 15. Community C case study results, Portland General Electric areas

Community C - PGE Current Energy Supply	Annual electricity use (kWh)	Current supply cost $/kWh	Current delivery cost $/kWh	Total current cost $/kWh	Total current annual energy cost
Residential	2,232,000,000	$ 0.069	$ 0.042	$ 0.111	$ 248,198,400
Commercial	2,519,000,000	$ 0.062	$ 0.028	$ 0.090	$ 227,717,600
Industrial	1,143,000,000	$ 0.055	$ 0.007	$ 0.062	$ 71,323,200
Total	5,894,000,000				$ 547,239,200
Community C - PGE ORO Program Scenario	**Annual electricity use (kWh)**	**ORO supply cost $/kWh**	**Current delivery cost $/kWh**	**Total ORO cost $/kWh**	**Total ORO annual energy cost**
Residential	2,232,000,000	$ 0.060	$ 0.042	$ 0.103	$ 228,819,055
Commercial	2,519,000,000	$ 0.058	$ 0.028	$ 0.086	$ 216,308,061
Industrial	1,143,000,000	$ 0.055	$ 0.007	$ 0.062	$ 70,870,598
Total	5,894,000,000				$ 515,997,714

Summary of Results

Table 16, below, restates the analysis and high-level results in each community so that can more easily be compared to each other.

Table 16. Summary of analysis and results

Case Study	A	B	C
Example Community	Medium Oregon town (population of ~90,000	Small Oregon town (population of ~10,000),	Large Oregon County (population of ~800,000)
Utility Territory	Pacific Power	Pacific Power	Mixed Pacific Power and Portland General Electric
ORO Application	Converting to 100% renewable energy, including 5% small, local renewable energy projects	Converting to 100% renewable energy, including 20% small local renewable energy projects	Converting to 100% renewable energy, including 20% small local renewable energy projects
Current Power Mix	• 77% carbon-based • 23% renewable	• 77% carbon-based • 23% renewable	Pacific Power • 77% carbon-based • 23% renewable Portland General Electric • 58% carbon-based • 42% renewable
ORO Application Power Mix	• 23% renewable retained • 36% new utility-scale wind • 36% new utility-scale solar • 5% small, local, renewable energy	• 23% renewable retained • 28.5% new utility scale wind • 28.5% new utility scale solar • 20% small, local renewable energy	• Renewable energy from both utilities retained • 5% small, local renewable energy • Remaining carbon-based energy replaced with 50% new utility scale solar and 50% new utility scale wind.
Impact	**Cost savings across all customer classes** compared to current power mix. For example, residential customers save $19/month on electricity.	**A mix of cost savings, cost increases and neutral impacts**. Electricity savings of $9 per month for residential customers, cost increases of $11 per month for commercial customers, and no change for industrial customers. Cost savings reappear across all customer classes if small projects are reduced to 14% of the electricity supply.	**Cost savings across all customer classes** compared to current power mix.

DISCUSSION

This analysis examined the potential rate impacts to investor-owned electric utility customers of HB 3221, the Oregon Renewable Options program, across different scenarios in three hypothetical Oregon communities. The flexibility of the ORO Program would enable many different kinds of implementation scenarios. Some communities may simply want to be supplied with enough renewable electricity to meet annual use, as studied in this analysis. Other communities may want to attempt to offset energy use at the time it occurs, a significantly more complex, and likely more expensive, proposition. These differences could have rate impacts that were not able to be studied in this analysis.

In the scenarios studied, which assume renewable electricity is procured just to meet overall annual use, customer cost savings are seen based on the difference in energy supply costs between renewable energy facilities and fossil fueled generators. While this analysis cannot account for all potential utility rate design considerations, the differential in costs between fossil resources and utility-scale renewable resources is significant. This difference may be able to absorb costs that were not factored into this analysis, such as the potential for stranded asset costs, and enable reasonable amounts of small-scale, local renewable energy projects to participate at higher costs, while providing additional non-energy co-benefits to their communities.

Due to the assumptions required to be made in this analysis, communities interested in participating in the ORO Program should not assume that cost savings would occur. Rather, the findings of this report indicate that for some implementation scenarios, overall customer rate changes might be negligible, with the potential for slight cost savings, neutral impacts, or slight cost increases.

This finding is consistent with anecdotal evidence from Oregon's Direct Access and Voluntary Renewable Energy Tariff programs, as well as the experience of California's electricity consumers using Community Choice Aggregation (CCA) programs. Under these programs slight cost savings or minimal cost increases were seen while switching energy supplies to higher portions of renewable electricity. Importantly, the ORO Program is *not* a CCA model and *under the ORO program consumers remain with their existing utility*.

The utilities' avoided costs rates used in this analysis should represent a conservative estimate of the costs needed to procure additional utility-scale renewable energy resources. In OPUC filings, both Pacific Power and Portland General Electric state that their published avoided cost rates for renewable resources are too high. Pacific Power states that the rates "may reflect an inherent overpayment"[26] while Portland General Electric says their pricing "far exceeds"[27] the true avoided costs of the utility. Using the utilities' published avoided cost rates in this analysis may overestimate the costs of procuring additional renewable energy resources and, therefore, underestimate the savings that customers would realize by switching to renewable energy sources under the ORO program. The magnitude of cost savings seen in the results is lower in

[26] UM1610 – Order 14-058. (2014). Page 6. https://apps.puc.state.or.us/orders/2014ords/14-058.pdf
[27] UM2000 – PGE's Response to Stakeholder Questions. (2019). Page 12. https://edocs.puc.state.or.us/efdocs/HAC/um2000hac16523.pdf

areas served by Portland General Electric due to the utility's higher avoided costs for renewable energy. As a result, industrial customers in Portland General Electric territory see the least apparent savings in that scenario, slightly less than 1% of total costs. If, indeed, Portland General Electric's avoided cost rates are too high, more savings could be available.

The rates needed for smaller scale, local projects to achieve financial viability, estimated as $0.08/kWh in this analysis, may depend on the project type and the variety of services or benefits that the project could provide to the community which go beyond typical delivery of electricity service. For example, projects that can provide backup power during grid outages, or other utility system ancillary services, may incur greater costs during installation to account for additional equipment needs. These benefits and services may have significant value at the local level but, because they are not valued at present through electricity rates, the additional costs may not be able to be recouped by the project owner or developer. HB 3221 could create a way for communities to work directly with projects in valuing local benefits that could be otherwise hard to value across the broader utility system.

If HB 3221 is adopted, the lower costs of electricity from utility-scale renewable energy facilities may enable communities to secure cost savings or negligible cost increases while switching to up-to-100% renewable energy while also gaining additional resilience, environmental, and clean energy workforce development benefits from local, smaller scale projects.

Important to OWRC's goals, based on the findings in this report, FCA believes that if HB 3221 were adopted it could increase the abilities of agricultural water suppliers to install renewable energy facilities that could support broader irrigation modernization goals.

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