Appendix 13. Renewable Energy Market Potential

Briefing Paper for the SageCon Partners
Estimates of Oregon Renewable Development through 2025

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Summary
This paper discusses likely Oregon wind, geothermal and solar development through 2025 at the megawatt (MW) and larger scale in rural Oregon.

Wind development from 2014 through 2020 is likely to be minimal if the federal production tax credit (PTC) is not extended.

If the PTC were extended through 2019, PacifiCorp and Portland General Electric (PGE) might develop a few hundred MW of wind in Oregon ahead of their renewable portfolio standard (RPS) compliance requirements for post-2020. If so, this question would be discussed before the Oregon Public Utility Commission in the two integrated resource plan (IRP) dockets in 2016 or 2017.

Through 2020 Oregon utilities have built projects sufficient to comply with the solar photovoltaic (PV) capacity standard under ORS 757.370, with the exception of 0.5 MW for Idaho Power. Further utility-scale projects are unlikely before 2020, absent changes in state laws. Some relatively small new geothermal projects are possible before the end of 2020.

Post-2020 the crystal ball becomes cloudier. Emerging geothermal and PV technologies could become commercial and make these technologies cost-competitive with power from natural gas. Material improvements in wind technology are also possible. The historical unpredictability of natural gas prices will likely re-emerge before 2020. Natural gas prices are likely to be higher than current levels, but no one knows how high.

Federal policies will also influence renewable development. Federal energy and carbon policies are hard to predict even a year into the future. Oregon policies will also change. The plausible range of Oregon wind, geothermal and solar development from 2020 to 2030 is from nearly zero up to a thousand MW for each resource.

Wind

Through 2020

The federal PTC credit for new projects ended Dec. 31, 2013. Only wind projects that began construction by the end of 2013 will get the PTC unless Congress extends it. Loss of the credit ($23 per megawatt-hour (MWh) or 2.3 cents per kilowatt-hour for 10 years) adds more than 25 percent to the cost of building wind projects. Without the credit, the cost of wind, relative to new natural gas-fired power plants, could be high enough to lead to a reexamination of the RPS. The cost comparison between new wind and gas-fired plants is uncertain because the price of natural gas over the next 20 years is uncertain.

As an example, PacifiCorp's 2013 IRP expects that even if the PTC is extended beyond the end of this year and set at its current level, new wind power plants will cost almost 30 percent more than power from a natural gas plant, based on the utility's gas price forecast and the kind of wind it modeled. Given its expectation that the PTC will not be extended, and with the banked renewable energy credits it already has for compliance with RPS requirements in Oregon, California and Washington, it plans no new wind or other renewable resources in Oregon until 2024.

If the PTC is extended, some new wind in Oregon is possible by 2020. Under a scenario in PacifiCorp's integrated resource plan where the PTC is extended to 2019 and then repealed, the company's optimization model picks 682 MW of wind (across its six-state system) during 2016-2019 to reduce PacifiCorp's cost of compliance with renewable portfolio standards (RPS) in Oregon and Washington post-2020 (scenario S-6). Under this scenario PacifiCorp would be building wind ahead of the date needed for RPS compliance to take advantage of the expiring PTC. While these possible wind acquisitions might be in Oregon, it is more likely they would be in Utah or Wyoming.

PGE would be in a similar situation in this scenario. If it built ahead of need, the amount would be less than for PacifiCorp. The likely locations would be Oregon or Washington. Assuming PTC extension, this issue would be discussed in the separate IRP proceedings for PGE and PacifiCorp in 2016 or 2017.

In the past, the output of some wind projects has been sold to Oregon utilities under Section 210 of the federal Public Utilities Regulatory Policy Act (PURPA) of 1978. PacifiCorp, Idaho Power and PGE plan to reduce their PURPA prices in the coming months due to reduced need for new resources to serve loads. If approved by the Oregon Public Utility Commission, this reduction would make new wind PURPA projects unlikely prior to 2020.

There are more than 1,200 MW of wind projects in Oregon dedicated to meet the California RPS. To qualify for the Category One tier under the California RPS today, eligible renewable energy must be delivered to a California balancing authority without substitution or through dynamic scheduling. Both methods require firm transmission capacity be assigned to the new wind project.

Given the constraints on transmission capacity from Oregon to California, it seems unlikely that major new wind projects will be built for export south, absent transmission upgrades. An August 2013 California PUC compliance report noted: "very few out-of-state power purchases are expected to qualify as Category One [RPS resources].[1]" All of the exceptions noted were from Nevada and Arizona.

There is about 140 MW of transmission capacity dedicated towards the export of power from the Boardman Coal Plant to California. This capacity will be freed up by the closure of the plant no later than the end of 2020. Some of this capacity has already been returned to PGE and might be used to export new wind projects to California, even before 2020.

It seems unlikely that wind projects would be built to serve out-of-state RPS markets other than in California, given lower RPS requirements in these states and the tendency to build in-state.

It is interesting to note that six large wind projects are under review in the Oregon Energy Facility Siting Council process. Two other wind projects with site certificates have not yet begun construction. (for the list and links to where these projects are in the process see: http://www.oregon.gov/energy/Siting/Pages/Facilities.aspx). If there is wind development in Oregon before 2020, it would likely come from these eight projects.

2021 through 2025

Land-based wind technology is relatively mature compared to solar and geothermal technologies. Still cost per installed kilowatt (kW) continues to decline. In recent years annual capacity factors in less robust wind regimes have improved (see http://emp.lbl.gov/sites/all/files/lbnl-6356e-ppt.pdf). Similar

[1] Slide 21 of http://www.nwcouncil.org/media/6877054/B-Monsen-NWPCC-Presentation-2013-09-05.pdf

improvements may continue. The larger uncertainties with wind project development are natural gas prices and state and federal policies.

In 2020 the Oregon RPS for PGE and PacifiCorp goes from 15 percent of retail electricity sales to 20 percent. In 2025 it goes to 25 percent and holds steady. According to its 2013 IRP, PacifiCorp sees little need for wind or other large generating resources before 2024. PGE released its draft IRP at the end of November. The IRP indicates a need for additional renewable resources shortly after 2020.

The 5 percent increment for the RPS added in 2020 for PacifiCorp and PGE would require 550 to 600 MW of new wind, depending on load growth. Not all of this capacity would be built in Oregon and not all of the Oregon projects would be within the sage grouse planning area.

Some Oregon consumer-owned utilities (COUs) might need additional renewable resources post-2020. This could occur if they fall under the "large" utility standard under ORS 469A.052 or if they are created from or expand into the service area of an electric company without the consent of the electric company. The possible amount ranges from zero to as much as 50 MW of new wind. A Bonneville Power Administration analysis of Oct. 24, 2013 indicates that, outside these circumstances, Oregon COUs will be able to satisfy Oregon RPS requirements through 2028 with the renewable energy certificates they will receive for Bonneville hydro efficiency upgrades.

California's RPS holds steady at 33 percent of sales from 2020 onwards. Even so, California utilities that are subject to the RPS will need to meet the requirements associated with load growth. Post-2020 expansion of the interties connecting Oregon and California is possible, especially for the direct current (DC) line from Celilo to Sylmar. That event could trigger additional renewable resource development in Oregon to meet incremental California RPS requirements.

Geothermal

Through 2020

The Neal Hot Springs geothermal project (near Vale, Oregon) was completed in 2012. It sells about 22 average MW to Idaho Power (25 MW nameplate). Geothermal power can be cost-competitive with natural gas power even without state or federal tax credits, depending on the quality of the resource. There are about 35 MW (nameplate) of geothermal projects under development in Oregon, not including the exploratory research at the Newberry Volcano by Alta Rock Energy, which is discussed below.

PGE and PacifiCorp are also open to good deals on geothermal projects by independent developers. It is difficult for utilities to recover the costs associated with dry holes, so they generally rely on independent developers.

2021 through 2025

The technology being developed by Alta Rock Energy holds great promise. If successful, it will avoid most dry-hole risk by injecting water into dry hot rocks. This technology has passed one major hurdle, with several ahead. If commercialized by 2020, it could open Oregon to many hundreds of MW of geothermal development from 2020 to 2030. Geothermal power that is cost-competitive with natural gas power could then be used to meet the RPS, serve load growth by Oregon utilities or replace power from coal plants that shut down.

PGE is committed to shut down the Boardman coal plant by 2020. The Centralia coal plant in Washington also has a planned closure by 2020. PacifiCorp and Idaho Power are considering shutting down some of their coal plants. The Environmental Protection Agency is developing rules for reducing carbon from existing power plants, with draft rules planned for June 2014. It is too early to tell what effect such rules may have on the other coal plants owned by Oregon utilities. Federal legislation to enact a cap-and-trade system for greenhouse gases or a carbon tax, if passed, would likely induce multiple coal plant shut-downs. Geothermal, wind or solar projects could replace part of the hundreds of MWs that these coal plants currently provide to Oregon.

Solar

Through 2020

ORS 757.370 requires PGE, PacifiCorp and Idaho Power to develop 20 MW of PV power by 2020. Their requirements are 10.9, 8.7 and 0.5 MW, respectively. Projects must be between 0.5 and 5 MW. For scale, a 5 MW project covers about 50 acres.

PGE and PacifiCorp have satisfied their PV capacity requirements. Idaho Power will likely satisfy its 0.5 MW requirement before 2016. Given the relatively high cost of PV power, not much beyond these amounts can be expected before 2021, absent changes in state or federal policies.

2021 through 2025

Post-2020 there is an emerging solar PV technology (perovskite) that could make new solar cost-competitive with new natural gas power, even absent federal or state tax credits. If so, many hundreds of MW of utility-scale solar projects could be built. These could be projects built to meet the RPS, serve load growth or replace power from existing coal plants.

This PV technology will need more laboratory development and commercialization before major deployment. This process will require a minimum of seven years and could take longer. There are also challenges related to the balance of system costs (other than the PV cells), electricity transmission and integration of the variable PV output. If these challenges are overcome, there could be several hundreds of MW of PV developed in Oregon during 2021-2025.

Drivers That May Affect Future Wind, Solar and Geothermal Development

The expiration of the wind PTC will end all possibility of new wind projects in Oregon before 2020 if it is not reversed in Congress. The wind industry is still optimistic that Congress will extend the PTC after a short hiatus as it has several times in the past. Congress might also enact other kinds of tax credits or other incentives for renewable power in the years ahead.

An unexpected rise in natural gas prices could make wind economic relative to natural gas power plants even without the PTC. Based on estimates in the PacifiCorp IRP for less robust wind regimes with the PTC, equivalence with wind occurs at natural gas prices of roughly $8 per million British thermal units (MMBtu). Most forecasters expect gas prices in the range of $4 to $6 in 2020 (in dollars of constant 2013 buying power). This assumes a PTC of $23 per MWh for the first ten years of operation. With the same assumptions about wind cost and performance, but without the PTC, the natural gas price would need to be around $11 per MMBtu. While possible, that price seems unlikely.

Alternatively, there could be a federal price on CO_2 emissions through a carbon tax or a cap-and-trade program. A price on carbon emissions has two effects on natural gas prices. One effect is related to the carbon content of natural gas fuel. A carbon tax of $30 per short ton of CO_2 would directly add $1.77 per MMBtu to the price of natural gas. In addition, a tax at this level or above would lead to the shutdown of most or all of the coal-fired power plants in the western U.S. This would increase the demand for natural gas used to generate electricity which would further boost the natural gas price.

If the U.S. were to impose a price on carbon emissions, it could raise natural gas prices enough to make wind and other renewable resources economic relative to new gas-fired power plants. It is unlikely that a carbon price high enough to have this effect will be in place before 2025. Still, a policy that locked in a gradual increase in the carbon price resulting in $100 per ton of CO_2 by 2030 would likely spur major renewable development in Oregon for the 2020 to 2030 period. At that price it would be cost-effective to replace existing coal-fired power with new wind power even without a PTC.

New transmission projects could enable export of wind or other Oregon renewables to meet the California RPS. Early indicators of new transmission would be planning studies by the Western Electricity Coordination Council or by regional transmission groups such as the Northern Tier Transmission Group or Columbia Grid.

As noted above there are several technology developments that could make geothermal or PV power cost-competitive with natural gas power plants post-2020 at projected natural gas prices, even without government incentives or new carbon policies.