Greenhouse Gas Reduction Goal Rate Impact Report

Report to the Oregon Legislature

2014

Public Utility Commission of Oregon

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Executive Summary

The 2009 Legislature enacted SB 101 to require the Public Utility Commission of Oregon to report before November 1 of each even-numbered year on the estimated rate impacts of Oregon's regulated electric and natural gas utilities achieving two greenhouse gas emission targets. The emission reduction targets are:

- Reduce greenhouse gas emissions 10 percent below 1990 levels by 2020.
- Reduce greenhouse gas emissions 15 percent below 2005 levels by 2020.

Electric Company Reductions and Rate Impacts

Greenhouse gases are emitted from the burning of fossil fuels (coal and natural gas) to generate electricity to supply the Oregon customers of Idaho Power Company (Idaho Power), PacifiCorp, and Portland General Electric Company (PGE). Idaho Power, PacifiCorp, and PGE identified additional resource actions they would need to take to achieve the greenhouse gas emissions reduction goals and then estimated the incremental rate impact of those actions.

Idaho Power – Under its current resource plan, Idaho Power is on track to achieve emission levels lower than both of the target levels. Because no additional actions are necessary, Idaho Power estimates zero rate impact with achieving the two emission reduction targets.

PacifiCorp – Under its current resource plan, projected emissions in 2020 would exceed both targets. To comply with the 10 percent reduction in emissions below 1990 levels, PacifiCorp would have to reduce its projected greenhouse gas emissions in 2020 by an estimated 16 percent. PacifiCorp assumes that it would reduce generation from its coal-fired power plants (and increase generation from its natural gas power plants by a like amount) to meet the target. PacifiCorp's estimated electricity rates in 2020 would be about 5.7 percent higher than otherwise projected.

To meet the 15 percent reduction below 2005 levels, PacifiCorp would have to reduce its projected greenhouse gas emissions in 2020 by an estimated 2.7 percent. PacifiCorp again assumes it would cut generation at its coal-fired power plants (and increase it at natural gas-fired power plants) to meet the target. Electricity rates in 2020 would be about .5 percent higher than otherwise projected.

Portland General Electric – Under PGE's current resource plan, PGE is on track to comply with the 15 percent below 2005 emission level target. Accordingly, there is no rate impact to meet this target.

To comply with the 10 percent reduction in emissions below 1990 levels, PGE would have to reduce emission in 2020 by an estimated 42 percent. PGE assumes it would shut down Boardman (as planned), discontinue taking service from the Colstrip coal units, and replace all discontinued generation with carbon-free resources such as wind and solar generation. PGE's electricity rates in 2020 would be about 39 percent higher than projected otherwise.

Natural Gas Company Reductions and Rate Impacts

Avista Utilities (Avista), Cascade Natural Gas Corporation (Cascade), and Northwest Natural Gas Company (NW Natural) serve Oregon's natural gas customers. These companies directly emit a small amount of greenhouse gases through distribution system and gas equipment leaks and direct burning for facility use and natural gas fleet vehicles (their emissions do not include emissions from the direct burning of natural gas for Oregon homes and businesses).

Northwest Natural, Cascade, and Avista each identified basic actions they could take to achieve the emission reduction targets. The rate impacts of the actions are minimal.

Introduction

In 2004, the Governor's Advisory Group on Global Warming recommended that greenhouse gas emissions targets should be codified. At that time, the United Nations Intergovernmental Panel on Climate Change estimated that global carbon dioxide emissions need to be reduced by 60-80 percent below 1990 levels to avoid dangerous interference with climate systems. In 2007, the Oregon Legislature passed HB 3543, which establishes non-binding greenhouse gas emission reduction goals for the state:

- Reduce greenhouse gas emissions 10 percent below 1990 levels by 2020.
- Reduce greenhouse gas emissions 15 percent below 2005 levels by 2020.

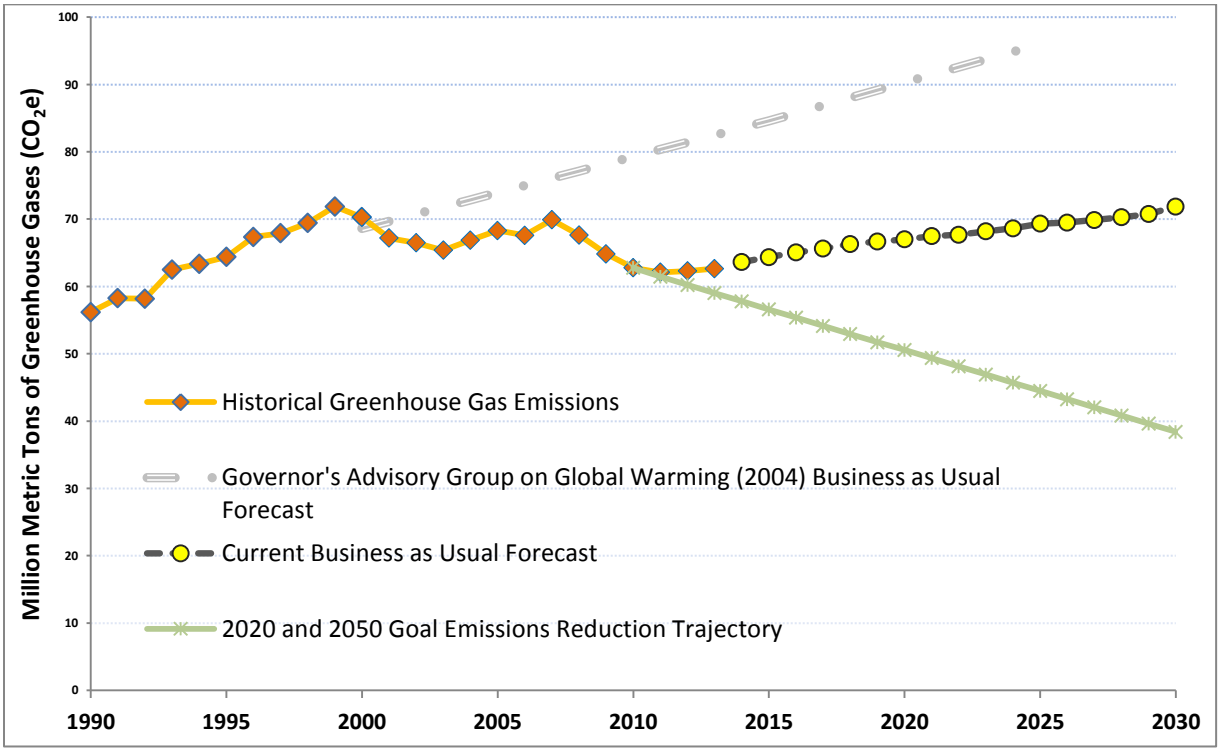
To establish these goals, the legislature made the following findings in HB 3543:

- Global warming poses a serious threat to the economic well-being, public health, natural resources, and environment of Oregon.
- Oregon relies on snowpack for summer stream flows to provide energy, municipal water, watershed health, and irrigation. Reduced snow pack, changes in the timing of stream flows, extreme or unusual weather events, rising sea levels, increased occurrences of vector-borne diseases, and impacts on forest health could significantly impact the economy, environment, and quality of life in Oregon.
- Oregon forests play a significant role in sequestering atmospheric carbon, and losing this potential to sequester carbon will have significant negative effect on the reduced carbon levels in the atmosphere.
- Oregon has been a national leader in energy conservation and environmental stewardship.

In 2009, the Legislature passed SB 101, requiring the Public Utility Commission of Oregon to report to the Legislature before November 1 of each even numbered year. This report should describe the estimated rate impacts from Oregon's regulated electric and natural gas companies in meeting greenhouse gas emission reduction goals in 2020.

The graphic on the next page shows Oregon's historic greenhouse gas emissions trends from all emission sources in the state, the current business as usual forecast, and the 2020 goal trajectory.

Figure 1: Oregon's historic greenhouse gas emissions trends



It is clear from the above graphic that since the development of the 2004 business as usual forecast Oregon has made significant developments to reduce its greenhouse gas emissions intensity. However, these actions are less than what is needed to meet the 2020 emission reduction goals set by the state. Additional action is needed to preserve the reductions established since 2005.

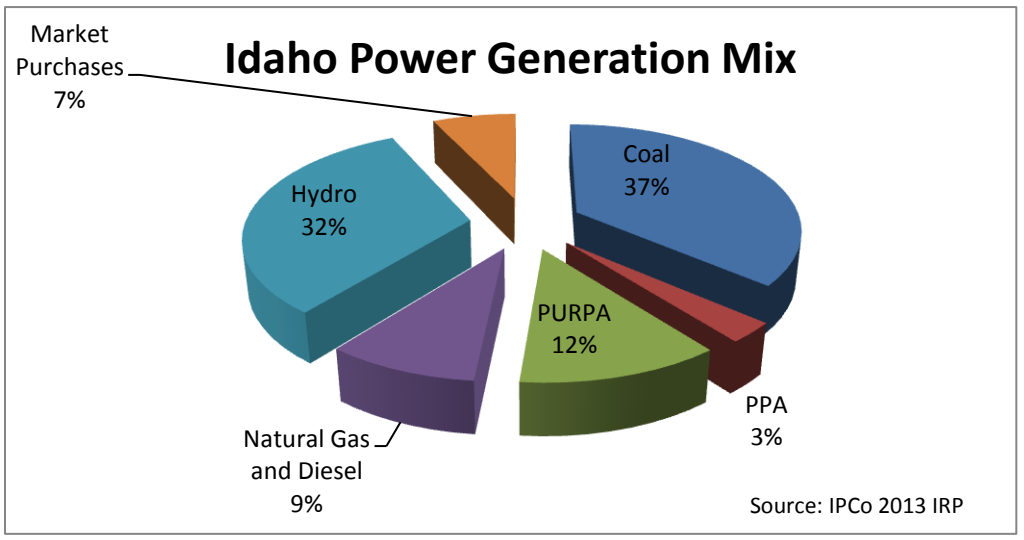
2014 Report Greenhouse Gas Reduction Goal Rate Impact Report

Idaho Power

Utility Background

In 2013, 78 percent of Idaho Power's supply of electricity came from company-owned generation resources. In above average water years, Idaho Power's low-cost hydroelectric plants are typically their largest source of electricity.

Figure 2: Idaho Power Generation Mix



Idaho Power is one of the few investor-owned electric utilities with a predominantly hydroelectric generating base. Idaho Power owns and operates 17 hydroelectric plants on the Snake River and its tributaries. Idaho Power also delivers power to its customers through one diesel-powered generator and shared ownership in three coal-fired generating plants. Idaho Power also owns three natural gas-fired plants.

In 2013, Idaho Power served 18,490 customers in Oregon, 13,350 of which were residential customers. Idaho Power delivered 648,176 megawatt-hours (MWh) to Oregon in 2013.

Emissions Reduction Report Information

Idaho Power is able to meet Oregon's 2020 greenhouse gas emissions goals on a business as usual basis. Using their 2013 Integrated Resource Planning projections Idaho Power is able to show how they would meet the reductions goals set by the legislature. This in turn means that Idaho Power is able to meet the goals without any additional cost to their Oregon ratepayers. In 2012, Idaho Power reported that they would need to reduce their greenhouse gas emissions by two percent from their planned operating assumptions as found in their 2011 Integrated Resource Plan. Several adjustments were made since

Idaho Power's 2011 Integrated Resource Plan (IRP). A summary of these changes can be found in the table below.

Table 1: Idaho Power 2011 and 2013 IRP Comparison

2020 Total System – Load / Resource Balance (MWh)			
	(A)	(B)	(B - A)
Generation Type	**2011 IRP – Energy Sources**	**2013 IRP – Energy Sources**	**Difference**
Hydro	8,582,948	8,629,602	46,654
Coal	6,100,442	5,090,108	(1,010,334)
Natural Gas	933,766	1,516,882	583,117
Resources Total	**15,617,156**	**15,236,592**	**(380,564)**
PURPA	1,772,611	1,975,515	202,903
PPA/ Other	535,429	536,406	977
Market Purchases	1,526,945	914,493	(612,452)
Surplus Sales	(1,111,375)	(2,390,464)	(1,279,089)
Load	**18,340,766**	**16,272,542**	**(2,068,225)**

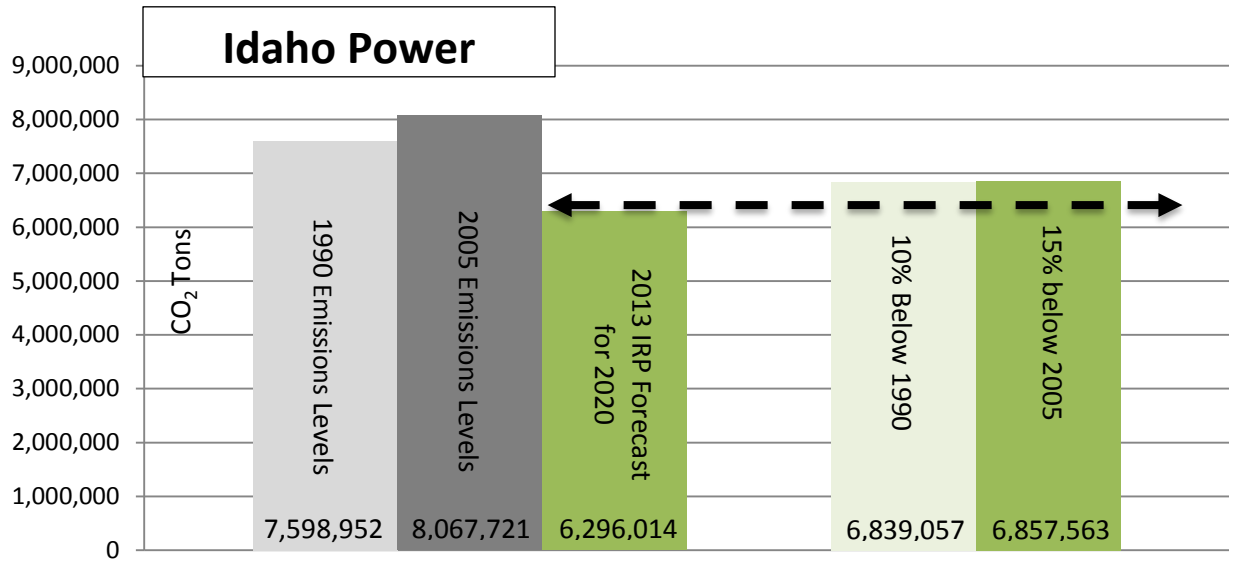
The forecasted hydro generation remains almost identical between the two IRPs while coal generation is reduced by over 1 million MWh and natural gas generation is increased by nearly 0.6 million MWh in the 2013 IRP. The combined result is a net decrease of nearly 0.4 million MWh of Company-owned generation. Because natural gas generation produces approximately 63 percent less carbon emissions than coal generation, the increase in natural gas generation of nearly 0.6 million MWh produces far less emissions than would the same amount of generation from a coal plant.

The analysis also shows that Idaho Power was able to increase PURPA purchases and lessen open market purchases, while increasing its natural gas capacity. This strategy additionally allows Idaho Power to re-dispatch existing coal purchases, relying less on this carbon intense resource in favor of more natural gas purchases.

Table 2: Idaho Power Emissions Comparison Table

Year	**Total System – CO_2 (tons)**
1990 Emission Levels	7,598,952
2005 Emission Levels	8,067,721
10% below 1990 Emission Levels	6,839,057
15% below 2005 Emission Levels	6,857,563
Year	**Total System – CO_2 (tons)**
2020 Emission Levels – 2013 IRP Projection	6,296,014

Figure 3: Idaho Power Emissions Comparison Bar Graph



The above bar graph and table (previous page) shows that Idaho Power is able to meet both emission reduction goals on a business as usual basis. Using their 2012 Integrated Resource Planning projections, Idaho Power demonstrated compliance with Oregon's emissions goal in large part by reducing coal generation by one million megawatt-hours, while increasing natural gas generation.

Consumer Rate Impacts

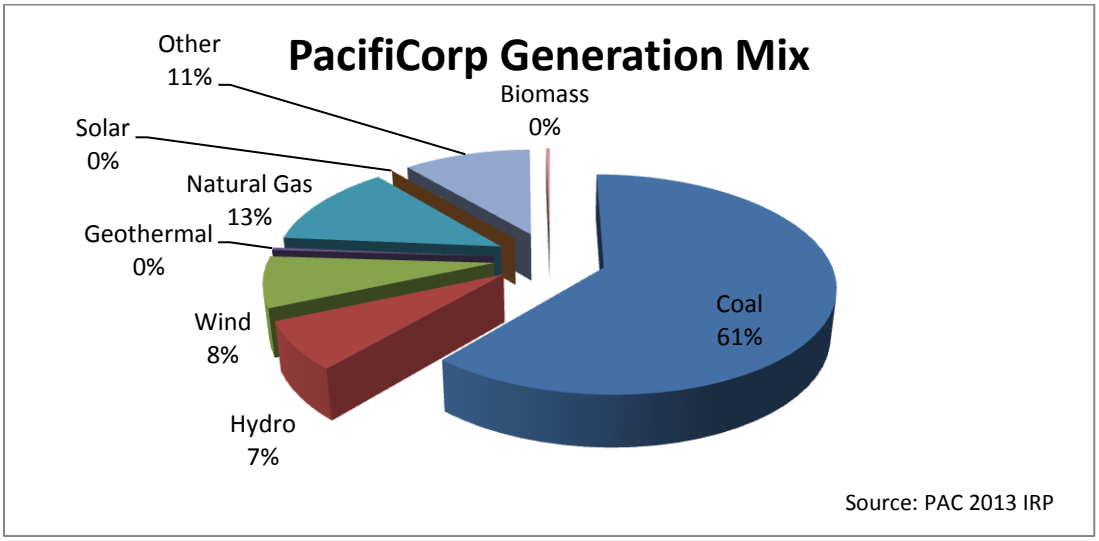
The Company estimates no rate impact associated with reducing carbon emissions.

PacifiCorp

Utility Background

PacifiCorp serves approximately 1.8 million customers in six states. In 1989, PacifiCorp merged with Utah Power & Light, and continues doing business as Pacific Power delivering electricity to customers in Oregon, Washington, and California, while Rocky Mountain Power delivers electricity to customers in Utah, Wyoming, and Idaho. The company owns 74 generating plants, including 43 hydroelectric plants. However, a majority of PacifiCorp's power comes from coal fired units. Today, PacifiCorp serves over 1,767,000 customers in their six state territories. In Oregon, PacifiCorp serves 562,072 customers.

Figure 4: PacifiCorp Generation Mix



Emissions Reduction Report Information

PacifiCorp conducted its analysis of Oregon SB 101 using its capacity expansion optimization model, System Optimizer, to develop a base resource portfolio and two resource portfolios that result in reductions of greenhouse gas emissions that are 10 percent below 1990 levels by 2020 and 15 percent below 2005 levels by 2020. While explained further below, to meeting Oregon's Greenhouse Gas (GHG) emissions goals PacifiCorp would re-dispatch serving Oregon load from PacifiCorp's existing coal fleet to its existing natural gas fleet. This shift in committed resources requires PacifiCorp to adjust how it serves customers in other states; this shift in resource strategy imposes additional costs to the PacifiCorp system which have been assessed to Oregon.

Table 3: PacifiCorp 2011 and 2013 IRP Comparison

2020 Total System – Load / Resource Balance (MWh)			
	(A)	(B)	(B - A)
Generation Type	**2011 IRP – Energy Sources**	**2013 IRP – Energy Sources**	**Difference**
Hydro	4,069,000	4,318,000	249,000
Coal	28,763,000	39,801,000	11,038,000
Natural Gas	19,968,000	12,365,000	(7,603,000)
Renewable	8,372,000	6,755,000	(1,617,000)
Existing Net Long Term Purchases	5,567,000	812,000	(4,755,000)
Front Office Transactions	2,511,000	2,522,000	11,000
Combined Heat and Power & Other	700,000	76,000	(625,000)
Class 1 DSM + Interruptibles	54,000	160,000	106,000
Net System Balancing Sales	(2,318,000)	(4,545,000)	2,227,000
Total Resources	**76,137,000**	**66,227,000**	**(9,910,000)**

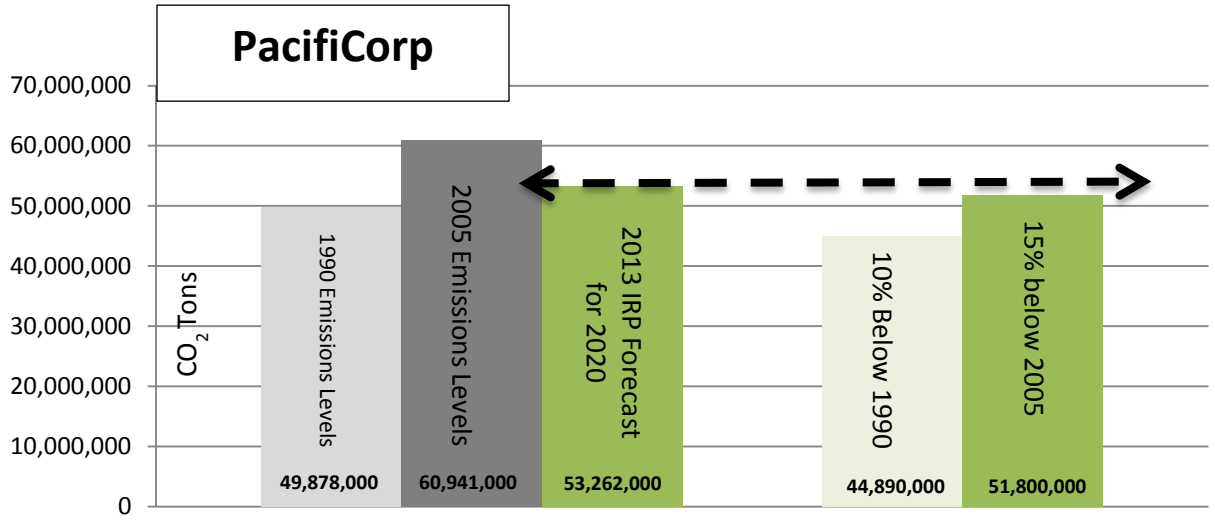
To develop the two portfolios that achieve targeted carbon dioxide emission reductions, the System Optimizer model was set up with hard annual carbon dioxide emissions caps. These caps constrain the model to solve for the least-cost resource expansion plan that does not exceed the physical carbon dioxide emission limits across PacifiCorp's multi-state system in each year of the simulation. Portfolio costs from the System Optimizer model were used in a revenue requirement model to calculate estimates of rate impacts associated with achieving the targeted carbon dioxide emission reductions.

PacifiCorp initiated its analysis from its 2013 Integrated Resource Plan Update (2013 IRP Update), revised to reflect the most recent official forward price curve dated March 31, 2014. The 2013 IRP Update portfolio was re-optimized to account for the impact of updated market prices, and the re-optimized portfolio is used as the base portfolio. Potential expansion resource options available in the current study are the same as those used in the development of the 2013 IRP Update. No retirements and/or conversion of coal units to operate as natural gas fired facilities beyond those in the 2013 IRP Update are included in the analysis. Similarly, resources that are not currently commercially available or financially viable are not included in the resource portfolios during the 2014 through 2020 study period covered by this analysis.

Table 4: PacifiCorp Emissions Comparison Table

Year	Total System – CO_2 (tons)
1990 Emission Levels	49,878,000
2005 Emission Levels	60,941,000
10% below 1990 Emission Levels	44,890,000
15% below 2005 Emission Levels	51,800,000
Year	**Total System – CO_2 (tons)**
2020 Emission Levels – 2013 IRP	53,262,000

Figure 5: PacifiCorp Power Emissions Comparison Bar Graph



The bar graph and table above shows PacifiCorp is very close to meeting the *15 percent below 2005 emissions goal*. However, to reach the *10 percent below 1990 emissions goal* PacifiCorp faces significant reductions. To reach the *10 percent below 1990 emissions goal*, PacifiCorp would serve Oregon by adjusting how they use and dispatch their natural gas generation fleet. This adjustment would impact resource utilization to serve other states. As a consequence, customers of PacifiCorp in Oregon would see an average annual impact of $72.34 per customer.

Rate impact of the models used by PacifiCorp

The figure below presents the customer impact for the study period of 2014 through 2020, on total and average annual basis for the two reduction scenarios: **Scenario 1** (*10 percent below 1990 levels by 2020*), and **Scenario 2** (*15 percent below 2005 levels by 2020*). The baseline revenue requirement forecast is based on the Company's 2013 ten-year business plan. The determination of customer impact assumes that all costs incurred to reach the Oregon goals set in Scenario 1 and Scenario 2 would be recovered from customers in Oregon.

Table 5: PAC Consumer Rate Impact

Relative to Preferred Portfolio			
		Scenario 1 (*10% below 1990*)	**Scenario 2 (*15% below 2005*)**
Customer Impact (%)	2014-2020	5.67%	0.45%
	Average Annual	0.81%	0.06%
Customer Impact ($/Customer)	2014-2020	$506.41	$39.95
	Annual Average	$72.34	$5.71

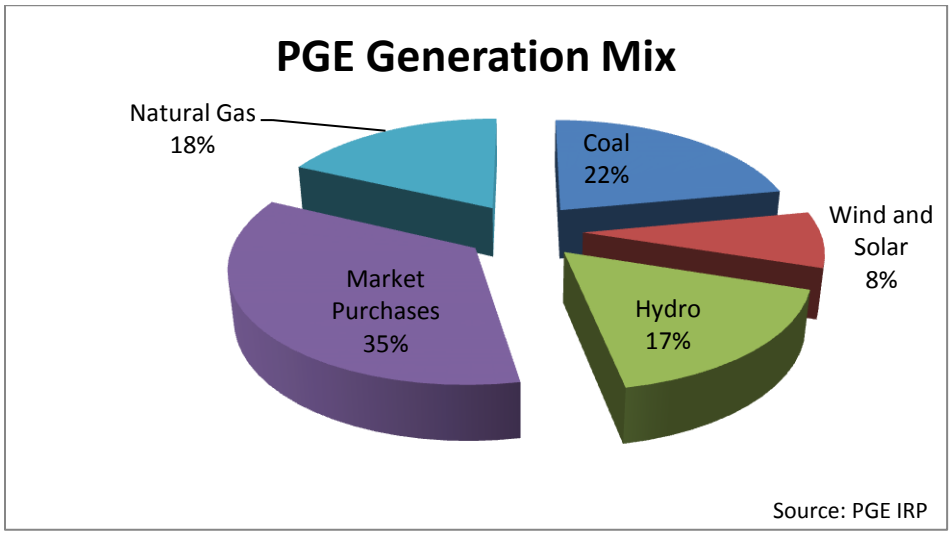
The above rate impacts reflect PacifiCorp's resource shift and acquisition strategy to meet Oregon's greenhouse gas goals. The greenhouse gas reduction requirements also force PacifiCorp into acquiring demand-side management resources in Washington, Idaho, Utah, and Wyoming. Additionally, in order to meet the *10 percent below 1990 goal* and the *15 percent below 2005 goal*, PacifiCorp will purchase less overall resources than under the IRP base case. This is because the basis of PacifiCorp strategy to meet Oregon's greenhouse gas goals is simply to re-dispatch from coal units currently serving Oregon load to natural gas fired units. This shift raises costs and requires PacifiCorp to acquire savings in service areas currently served by the re-dispatch natural gas generator now dedicated to Oregon under the greenhouse gas goals scenarios.

Portland General Electric

Utility Background

Portland General Electric (PGE) has provided electricity to customers in the northern Willamette Valley since 1889. Today, PGE serves customers within a 4,000-square mile service territory including 52 Oregon cities. PGE distributes electricity to customers in parts of Multnomah, Clackamas, Marion, Yamhill, Washington, and Polk counties – 44 percent of the population of Oregon. PGE currently serves 833,129 retail customers at an average residential rate of 10.46¢ per kilowatt hour. PGE is a minority share owner of Coalstrip Generating Station in Rosebud County, Montana.

Figure 6: PGE Generation Mix



PGE produces and purchases energy primarily from coal and natural gas plants, as well as hydroelectric power from dams on the Clackamas, Willamette, and Deschutes rivers. Between 1976 and 1993, PGE operated Trojan, the only nuclear power plant in Oregon. The company elected to close the plant twenty years early.

Table 6: PacifiCorp 2011 and 2013 IRP Comparison

2020 Total System – Load / Resource Balance (MWh)			
	(A)	(B)	(B - A)
Generation Type	2009 IRP – Energy Sources	2013 IRP – Energy Sources	Difference
Hydro	3,045,785	2,748,750	(297,035)
Coal	4,004,187	4,624,220	620,033
Natural Gas	5,761,200	8,938,862	3,177,663
Resources Total	**12,811,172**	**16,311,833**	**3,500,661**
PURPA	-	88,523	88,523
PPA/ Other	(C) 2,069,396	266,858	(1,802,538)
Market Purchases	5,424,677	2,248,455	(3,176,222)
Surplus Sales	80,632	1,544,470	1,463,838
Load	**20,224,613**	**17,371,199**	**(2,853,414)**
Owned RPS	(D) 4,871,228	3,148,088	(1,723,140)
Total Portfolio Demand	(C) **25,095,841**	**20,519,287**	**(4,576,554)**

(A) 2009 IRP Addendum - 2020 energy composition based on AURORA dispatch of PGE's preferred portfolio: "Boardman through 2020"
(B) 2013 IRP - 2020 energy composition based on AURORA dispatch of PGE's preferred portfolio: "Baseload Gas/RPS only"
(C) 2009 IRP "Total Portfolio Demand" and "Other" include approximately 130 MWa of ETO EE (base case) modeled as a resource for portfolio analysis purposes (i.e., they are greater by this amount); in PGE's 2013 IRP, the energy and capacity associated with the base case ETO EE were included in the load forecast and not modeled as a resource for portfolio analysis purposes.
(D) Represents Owned Renewable Resources; certain PPA contracts may be used for RPS compliance.
* Five years after the "Great Recession" of 2008-2009, its effect continues to be manifest in slower than anticipated economic recovery and associated energy demand growth. The pace at which the economy is returning to historically normal employment rates, business growth and economic activity has been slower than expected and well below prior economic recoveries. PGE's low to flat load growth is also driven in part by curtailments or closures among paper and solar manufacturing customers.

Emissions Reduction Report Information

PGE Modeling Approach

The *10 percent carbon reduction by 1990 goal* is met by discontinuing taking service from coal-fired operations at Colstrip on December 31, 2020. For rate impact estimation, the present value of fixed revenue requirements associated with the remaining unrecovered investment as of year-end 2019 is recovered in 2020. Resources are added to the model portfolios in 2019, 2020, and 2012. All portfolios include 372 MW of Pacific Northwest wind generation added in 2020 to maintain physical RPS compliance; for purposes of this analysis, these RPS resources have no effect on the incremental cost of achieving the stated emissions reductions. For electricity supplied through net market purchases, standard offer sales, and electricity service suppliers, PGE used 900 pounds CO_2 per MWh as a reasonable carbon content assumption.

Discussion of the 1990 Emissions Baseline

When evaluating efforts to reach the *10 percent below 1990 levels goal*, it is important to recognize that, in 1990, PGE served approximately 60 percent of its retail load from non-carbon dioxide-emitting generation sources, specifically from nuclear and hydroelectric resources. Since then, PGE's Trojan Nuclear Plant has closed. Additionally, PGE has lost access to a significant portion of mid-Columbia hydroelectric power contract. These non-carbon dioxide generation losses are compounded because retail loads have increased by more than 25 percent during the same period.

Discontinuation of Coal-Fired Operations at Boardman

Achieving either the 1990 or 2005 carbon dioxide emissions reduction targets requires the discontinuation of coal operations at Boardman. Given that Boardman coal operations will cease at year-end 2020, the 1990 and 2005 targets are assessed in this report beginning January 1, 2021, rather than one year earlier. To use a Boardman closure date of January 2020 would create significantly higher retail rate impacts, which seem unnecessary given the scheduled retirement of Boardman in 2020.

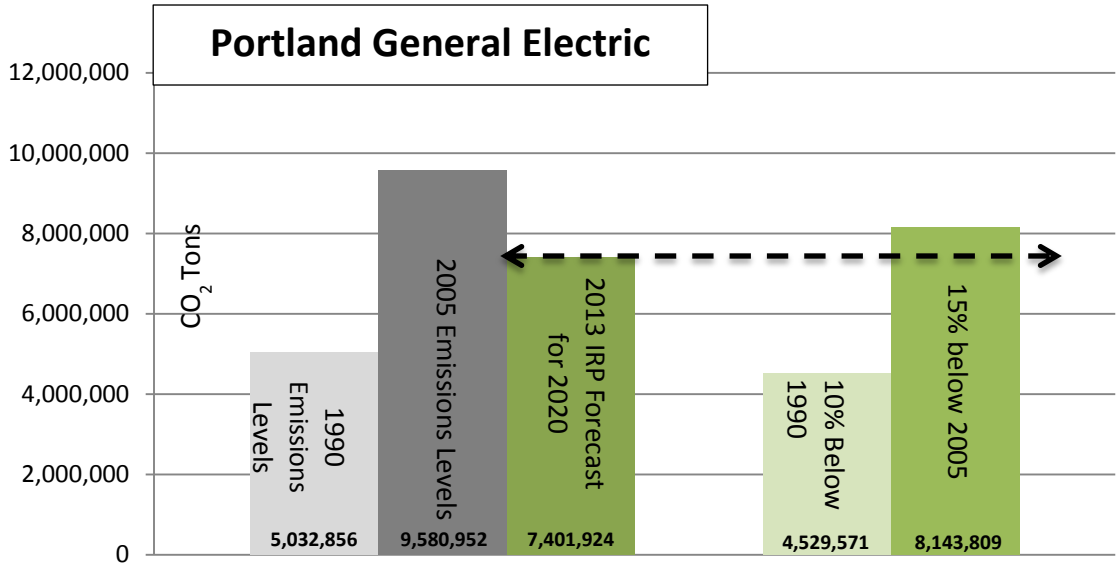
Disposition of Colstrip 3 and 4

Reaching the *10 percent below 1990 goal* in 2021 requires essentially displacing Colstrip Units 3 and 4 from PGE's generation portfolio. For purposes of this assessment, PGE assumed that both units would be displaced at year-end 2020 with a one-year recovery in 2020 of the remaining investment.

Table 7: PGE Emissions Comparison Table

Year	**Total System – CO_2 (tons)**
1990 Emission Levels	5,032,856
2005 Emission Levels	9,580,952
10% below 1990 Emission Levels	4,529,571
15% below 2005 Emission Levels	8,143,809
Year	**Total System – CO_2 (tons)**
2020 Emission Levels – 2013 IRP	7,401,924

Figure 7: PGE Emissions Comparison Bar Graph



The above bar graph and table shows that PGE will meet the *15 percent below 2005 emissions goal* through business as usual. However, this assumes adjusting the assumed compliance period to be in line with the closure of the Boardman Generating Plant year end 2020. In 1990, PGE was utilizing very different resources than resources currently procured to serve customers. Until its decommissioning in 1993, much of the power PGE used to meet demand was generated by the Trojan Nuclear Plant, a greenhouse gas emissions free resource. Additionally, the company carried contract options to take service from the mid-Columbia river dams. PGE would need to significantly change is resource portfolio to meet the *10 percent below 1990 emissions goal*. This would include replacing the Boardman generating plant entirely with greenhouse gas free resources and discontinuing taking output from Montana's Colstrip Power Plant, a current major source of energy and base load power for PGE.

Table 8: Rate impact of the models used by PGE

10% Below 1990	**Relative to Preferred Portfolio**				
	Colstrip one-time: January 1 to December 31	**On-going Cost: Replacement Resources**	**Incremental Revenue Requirement ($ millions)**	**Total Customers**	**Incremental Dollars per Customer per Year**
2019 Rate Impact (%)	0.0%	-4.7%	$(86)	898,291	$(96)
2020 Rate Impact (%)	8.6%	6.5%	$189	909,636	$208
2021 Rate Impact (%)	-11.2%	39.5%	$717	921,125	$779
Cumulative Increase vs. 2013 IRP Preferred Portfolio		**38.7%**	**$717**		

The above table demonstrates the when PGE models compliance with the *10 percent below 1990 emission levels goal* the cost to ratepayers is significant. Please keep in mind that this scenario relies on several assumptions about reliability, resource replacement, and costs that have not been fully vetted by the Commission in a formal proceeding. Additionally, the law, as written, assumes compliance by January 1, 2020. Boardman Generating Plant is not scheduled for closure until year-end 2020. To comply with the greenhouse gas goals by January 1, 2020, PGE would need to find greenhouse gas free replacement generation for year 2020. Those costs are significant and are not reflected in the above cost table.

Natural Gas Utilities

Northwest Natural

Utility Background

NW Natural, formerly Northwest Natural Gas Company, is headquartered in Portland, Oregon. Primarily a natural gas distributor, the company services residential, commercial, and industrial customers in Western Oregon and Southwest Washington. Founded in 1859, the company has approximately 680,000 customers and revenues of nearly one billion in US dollars annually.

NW Natural is Oregon's largest natural gas utility. It serves customers along the Oregon Coast, in the Willamette Valley, the Columbia River Gorge, and the Portland metropolitan area. The company operates an underground natural gas storage facility near Mist, Oregon, in the Northern Oregon Coast Range utilizing depleted gas wells, as well as a facility near Fresno, California. These former wells allow the company to purchase gas when prices are lower and store gas until needed during peak consumption times in the winter.

Emissions Reduction Report Information

NW Natural identified its sources of greenhouse gas emissions as: 1) its operations and facilities, 2) its natural gas and electric power usage for operations, including compressors, 3) its operation of fleet vehicles to service customers, and 4) natural gas leaks commonly referred to as fugitive emissions.

NW Natural does not have historical energy consumption data necessary for determining its 1990 or 2005 GHG emissions. The company began its analysis by establishing its 1990 and 2005 emissions. For this report, NW Natural uses the average emissions for 2008 and 2009 as the proxy for both 1990 and 2005. The company believes this is a reasonable assumption because, in spite of serving more customers, it is more efficient, has a tighter system, and has fewer employees now than it had in 1990.

In 2013, the NW Natural's greenhouse gas emissions were four percent lower than the 1990 and 2005 levels. If their greenhouse gas emissions are unchanged through 2020, then some greenhouse gas emission reductions will be necessary to meet the *10 percent below 1990 reduction goal*.

Table 9: Northwest Natural Emissions Comparison Table

Year	Total System – CO_2 (tons)
1990 Emission Levels	90,721
2005 Emission Levels	90,721
10% below 1990 Emission Levels	81,649
15% below 2005 Emission Levels	77,113
Year	**Total System – CO_2 (tons)**
2020 Emission Levels	87,513

Because reduction activities and their costs cannot yet be known, it is likely that NW Natural would have to purchase offsets to meet the goal. NW Natural assumes the cost of offsets needed to achieve the *goal of 10 percent below 1990 levels* would be $59,813. The offsets needed to achieve the *goal of 15 percent below 2005 levels* have an estimated cost of $106,080. These values are based on the Base Case carbon dioxide price forecasts. Besides having a cost for carbon dioxide embedded in the gas price forecast used in the Base Case, the current IRP also explores two additional sensitivities at higher carbon dioxide values. While it is very difficult to estimate the costs of offsets in the future, the $10.20 per ton offset is similar to the costs of offsets experienced by the Company in its Smart Energy™ Program.

Table 10: NWN Customer Rate Impact

		Scenario 1 (10% below 1990)	Scenario 2 (15% below 2005)
Estimate Cost of Carbon Abatement using Offsets		$59,813	$106,080

The above table shows that Northwest Natural's efforts in meeting the state's greenhouse gas emissions goals would have a de minimis impact to rates and ratepayers. The total cost of purchasing carbon offsets to assist the company in reaching greenhouse gas goals is less to $170,000 or 25 cents per customer.

Cascade Natural Gas

Utility Background

Today, Cascade serves more than 260,000 customers in 96 communities – 68 of which are in Washington and 28 are in Oregon. Cascade's service areas are concentrated in western and central Washington and central and eastern Oregon.

Cascade serves a diverse territory covering more than 32,000 square miles and 700 highway miles from one end of the system to the other. Interstate pipelines transmit Cascade's natural gas from production areas in the Rocky Mountains and western Canada. The Cascade headquarters is located in Kennewick, Washington.

Emissions Reduction Report Information

Cascade Natural Gas does not have historical energy consumption information available for determining its 1990 or 2005 greenhouse gas emissions. Therefore, 2011 results were used for determining the 2020 goals. Cascade further believes its emissions related to its fleet and office facilities will remain steady through 2020. The company states that it is mindful to ensure that it makes energy efficient equipment purchases, building retrofits, and new fleet choices.

Table 11: Cascade Natural Gas Emissions Comparison Table

Year	**Total System – CO_2 (tons)**
1990 Emission Levels	702.62
2005 Emission Levels	702.62
10% below 1990 Emission Levels	632.36
15% below 2005 Emission Levels	597.23
Year	**Total System – CO_2 (tons)**
2020 Emission Levels	839.21

Table 12: Cascade Natural Gas Customer Rate Impact

		Scenario 1	**Scenario 2**
Estimated Cost of Carbon Abatement using Offsets		$1,493	$2,240

The above table shows that Cascade's efforts in meeting the state's greenhouse gas emissions goals would have a de minimis impact to rates and ratepayers. The total cost of purchasing carbon offsets to assist the company in reaching the greenhouse gas goals is less to $3,800 or 1.5 cents per customer.

Avista Utilities

Utility Background

Avista Utilities generates and transmits electricity and also distributes natural gas for residential, commercial, and industrial customers. Approximately 1,550 employees provide electricity, natural gas, and other energy services to 359,000 electric and 320,000 natural gas customers in three western states. Their service territory covers 30,000 square miles in eastern Washington, northern Idaho, and parts of southern and eastern Oregon, serving a population of 1.5 million people.

The company was founded in 1889 as Washington Water Power Company, until 1998, when the board of directors approved a name change to Avista Utilities. In Oregon, Avista serves natural gas customers in La Grande, Roseburg, Medford, and Klamath Falls.

Emissions Reduction Report Information

Avista does not have historical energy usage information or fuel consumptions from its fleet vehicles available in order to calculate its 1990 and 2005 GHG emissions. Therefore, for the purposes of this report, the company used the average emissions from 2009 through 2011, 658 metric tons, as a proxy for both its 1990 and 2005 emissions levels. The company believes this to be a reasonable and conservative assumption for the following reasons:

1. Avista has the same number of overall office and operational facilities; however several of the facilities have had energy efficiency upgrades since 1990 and 2005. The company has also reduced staffing, particularly as it relates to Contact/Call Center operations and meter readers due to a reduction in meter reading with the deployment of Automated Meter Reading (AMR) in 2004.
2. The Company is operating fewer vehicles due to, among other things, a reduction in metering reading with the deployment of AMR as mentioned above.

By using an average emissions proxy of 2009-2011, the baseline is likely lower than it was both in 1990 and 2005.

As it relates to the company's estimates of carbon dioxide emissions between 2012 and 2020, the total emissions in the State of Oregon begin at a very low threshold. While Avista will continue to seek out energy efficiency measures at its office facilities, and seek out less carbon dioxide intensive fleet vehicles (i.e., CNG, Hybrid, etc.), Avista believes overall emissions between 2012 and 2020 will remain somewhat flat, as any reduced emissions may be offset by increased emissions caused by the company serving more customers.

Table 13: Avista Utilities Emissions Comparison Table

Year	Total System – CO_2 (tons)
1990 Emission Levels	658
2005 Emission Levels	658
10% below 1990 Emission Levels	593
15% below 2005 Emission Levels	560
Year	**Total System – CO_2 (tons)**
2020 Emission Levels	642

Table 14: Avista Utilities Customer Rate Impact

		Scenario 1	Scenario 2
Estimate Cost of Carbon Abatement using Offsets		$548	$822

The above table shows that Avista's efforts in meeting the state's greenhouse gas emissions goals would have a de minimis impact to rates and ratepayers. The total cost of purchasing carbon offsets to assist the company in reaching the greenhouse gas goals is less to $1,500 or half a cent per customer.

Appendix

Appendix 1

Summary of Prior Report

The 2012 *Greenhouse Gas Reduction Goal Rate Impact Report* submitted to the legislature by the Public Utility Commission found the following:

10 percent below 1990 levels by 2020:

- **Idaho Power** would have to **reduce its greenhouse gas emissions in 2020 by 2 percent** from the level projected in its 2011 Integrated Resource Plan (IRP). Idaho Power assumes that it would meet that emissions goal by curtailing coal fired generation. Idaho Power's estimated electricity rates in 2020 would be about **0.1 percent higher than current rates**.
- **PacifiCorp** would have to **reduce its greenhouse gas emissions in 2020 by 23 percent** from the level projected in its most recent 2010 IRP. PacifiCorp assumes that it would have to reduce generation from its coal fired plants and add significant amounts of renewable resources, natural gas fired resources, energy conservation, and demand response resources. PacifiCorp's estimated electricity rates in 2020 would **8 percent higher than current rates**.
- **PGE** would have to **reduce its greenhouse gas emissions in 2020 by 54 percent** from the level projected in its current IRP. To reduce emissions, in addition to the planned shutdown of its Boardman coal fired plant, PGE assumes that it would have to discontinue taking service from the Colstrip coal fired power plant and replace the associated generation with renewable resources, among other actions. Following this course of action, PGE's estimated electricity rates in 2020 would be **34 percent higher than current rates.**

15 percent below 2005 levels by 2020:

- **Idaho Power** would have to reduce its greenhouse gas emissions in 2020 by 2 percent from the level projected in its 2011 IRP, which is similar to meeting *the 10 percent below 1990 goal*. Idaho Power assumes that it would meet that emissions goal by curtailing coal fired generation. Idaho Power's estimated electricity rates in 2020 would be about **0.1 percent higher than current rates**.
- **PacifiCorp** would have to **reduce its greenhouse gas emissions in 2020 by 11 percent** from its projected 2010 IRP level. PacifiCorp assumes that it would reduce generation from its coal fired plants and add natural gas fired resources, energy conservation, and some renewable resources. PacifiCorp's electricity rates in 2020 would be **4 percent higher than current rates.**
- **PGE** would have to **reduce its greenhouse gas emissions in 2020 by 20 percent** from the projected 2010 IRP level. PGE assumes it would achieve this goal through the planned

shutdown of its Boardman coal fired plant, discontinue taking service from the Colstrip coal fired power plant, and replacing the associated generation with a mix of natural gas and renewable resources, among other actions. PGE's electricity rates would be an estimated **8 percent to 14 percent higher than current rates.**

Natural Gas Company Reductions and Rate Impacts

The greenhouse gas emissions attributable to Oregon's natural gas companies – Avista, Cascade, and NW Natural – largely stem from distribution system and gas equipment methane leaks. Their greenhouse gas emissions also include company facility energy usage and operation of company fleet vehicles. These emissions do not include the emissions from burning natural gas directly in homes and businesses, and are small in comparison to the emissions from direct burning of natural gas.

For this report, Avista, Cascade, and NW Natural identified actions that each could take to achieve the greenhouse gas emissions reduction goals. The three natural gas companies estimate that each would have to reduce their 2020 emissions by 10 percent to reach the *10 percent less than 1990 goal* and 15 percent to reach the *15 percent less than 2005 goal*. To meet the greenhouse gas emissions reduction goals the estimated rate increase is significantly less than one percent for each of the three natural Gas Companies.

Appendix 2

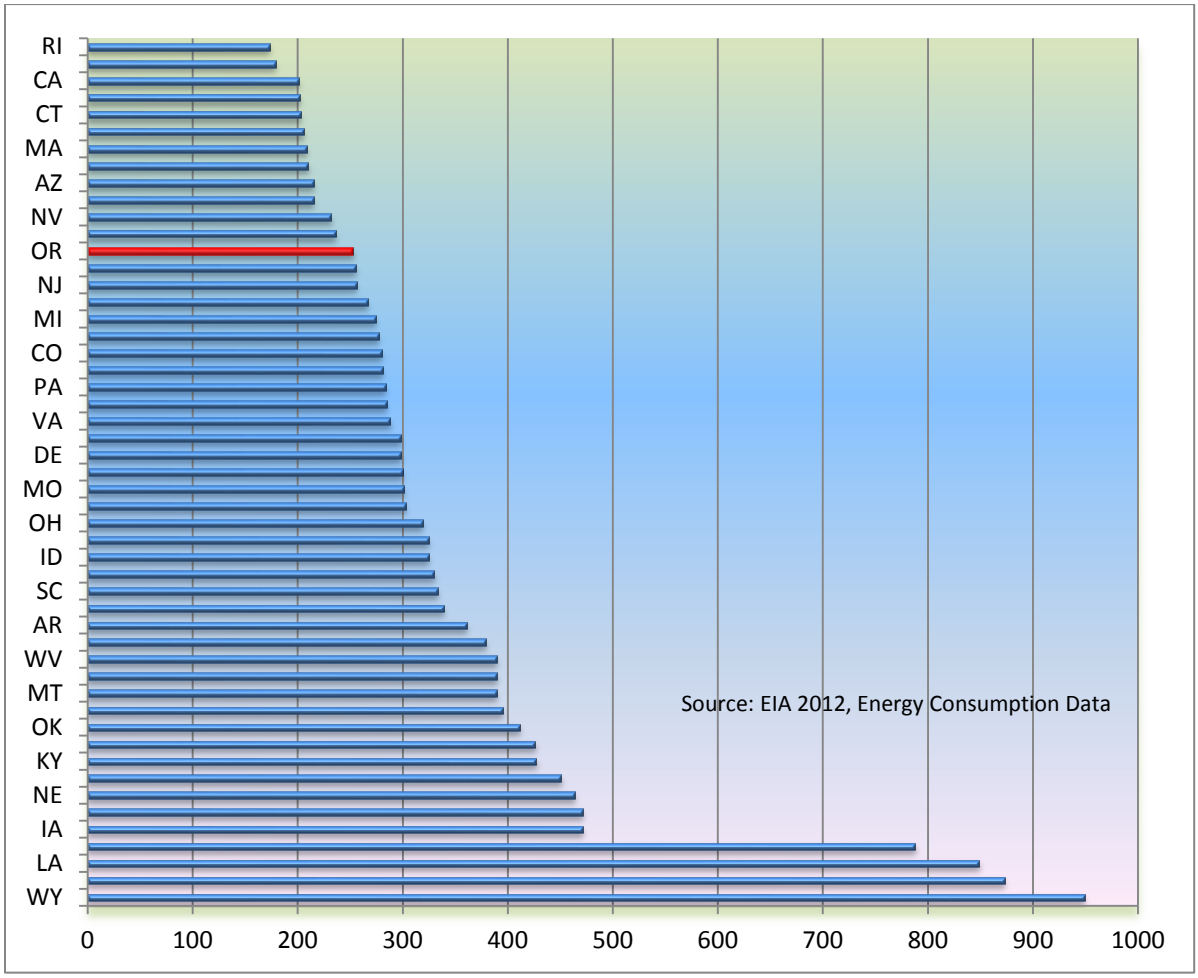
State Electricity Greenhouse Gas Emission Reduction Activities Summary

The State of Oregon has made investments in multiple activities to lower its overall greenhouse gas intensity of the electricity sector. Although these investments occur independently of one another, they represent the pieces of what could be an overall climate change strategy.

Energy Efficiency Investments

Oregon is a national leader in energy efficiency policy, acquisition, and program development. Oregon has invested in energy efficiency both within the regulated electricity business sector and the consumer owned electricity business sector. This investment has an overall net benefit to Oregon electricity customers. These investments innately lessen the greenhouse gas intensity of electricity usage in Oregon and stretch the capacity of current electricity investments. Oregon's cost effective investment in energy efficiency has helped the state and its utilities make progress in meeting the 2020 greenhouse gas goals. Additionally, Oregon's investment in energy efficiency has helped the state rank among the lowest in the country for energy usage per capita.

Figure 8: Rankings of Total Energy Consumed per Capita, 2012 (million Btu)



Renewable Energy, Renewable Portfolio Standard (RPS)

Oregon's RPS was enacted in 2007 through Senate Bill 838. The law requires utilities to deliver a certain percentage of their electricity from renewable resources by 2025. For Oregon's three largest utilities (PGE, Pacific Corp, and Eugene Water and Electric Board) the standard started at 5 percent in 2011, increases to 15 percent in 2015, 20 percent in 2020, and 25 percent in 2025. All other electric utilities in the state, depending on size, have standards of 5 percent or 10 percent in 2025. The renewable portfolio standard has also assisted the state's investor owned utilities meet the 2020 greenhouse gas target. Each electric utility's strategy to meet the state's greenhouse gas goals includes incremental investment in renewable energy beyond the requirements of the RPS. Without the resources of RPS, the state would not be able to meet the greenhouse gas goals.

The Boardman Shutdown

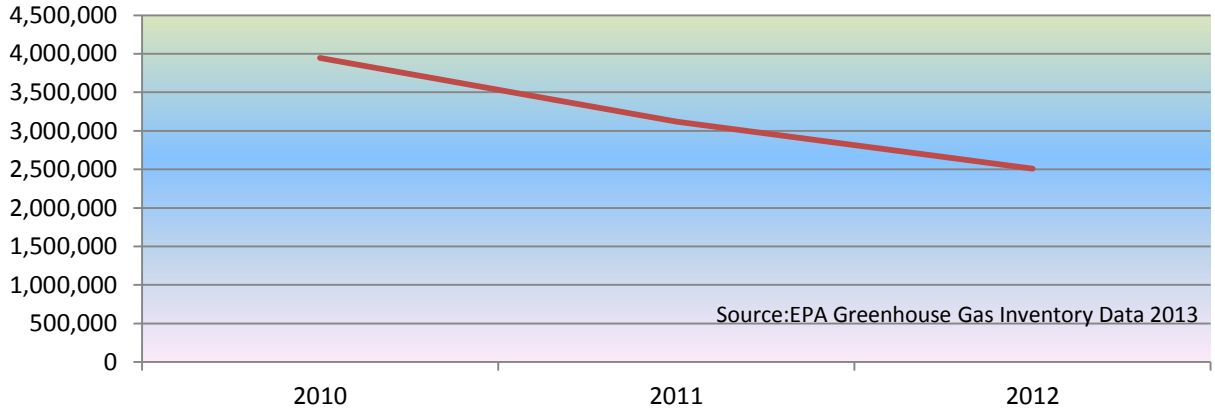
The Boardman plant was authorized in 1975, just two years before the 1977 Clean Air Act amendments, which would have required the plant to meet stricter emission standards. The plant currently accounts for 65 percent of stationary sulfur dioxide emissions, and 7 percent of carbon dioxide emissions in

Oregon. PGE's original plan involved operating the plant until 2040; this would have required installing over $500 million of pollution control equipment on the plant by 2017 in order to comply with federal and state clean air standards. In early 2010, however, PGE announced that they were considering an alternative plan for the Boardman plant that would close it in 2020.

In April 2010, PGE decided to close the plant in 2020 to save $470 million in upgrades that it would have been required to install had it kept the plant operating until 2040. In December 2010 the Oregon Department of Environmental Quality approved the plans for the 2020 closing.

The Boardman plant is one of PGE's largest power stations, producing roughly 15 percent of PGE's electricity. Boardman represents between 3,800,000 and 2,500,000 tons of carbon dioxide emissions per year depending on the number of hours the plant is dispatched.

Figure 9: Report Emissions for Boardman: Metric Tons CO_2e



Boardman is Oregon's only coal fired power plant. With the closure of Boardman, Oregon has made substantial progress in lowering the state's overall carbon intensity. Additionally the closure of Boardman will assist PGE in meeting the State's greenhouse gas goals.

The Governor's 10-year Energy Action Plan is a major component of a climate change strategy. The Governor's 10-year Action Plan expects reductions in greenhouse gas emissions associated with energy usage from electricity and transportation.

Senate Bill 844

In 2013, the Oregon Legislature passed Senate Bill 844 directing the Public Utility Commission (PUC) to establish rules to allow natural gas utilities to submit applications for voluntary greenhouse gas emission reduction projects. Draft rules have been submitted to the Secretary of State and a Commission rulemaking will conclude in the fourth quarter of 2014.

Senate Bill 306

In 2013, the Oregon Legislature passed Senate Bill 306 directing the Legislative Revenue Officer to prepare a report for the Legislature on the feasibility of imposing a clean air fee or tax on a statewide basis. Portland State University's Northwest Economic Research Center has contracted with the

Legislative Revenue Office to complete a carbon tax study and recommendations. The report is expected by the end of the year.

The following is a list of Oregon activities that have effected energy usage, conservation, and greenhouse gas emissions. The legislature has a long history of action to address energy usage, energy costs, and safety in Oregon, a record recognized nationally and internationally and a record for which the State and its citizenry takes great pride.

Governor Kitzhaber's 10 year Energy Plan:

On December 17, 2012, Governor Kitzhaber released a 10-year Energy Action Plan that protects Oregon consumers and ensures energy investment made today will strengthen the economy. The plan presents three core strategies where the state can play a lead role in innovation, policy development, and market transformation:

1. Meeting 100 percent of new electric load growth through energy efficiency and conservation.
2. Enhancing clean energy infrastructure development by removing finance and regulatory barriers to attract new investment and pursue promising new technologies.
3. Accelerating the market transition to a more efficient, lower-cost, and cleaner transportation system, including strategies for fleet vehicle conversion and access to cleaner-burning and more efficient vehicles.

Table 15: State Energy Timeline Highlights

State Energy Timeline Highlights	
1971	Oregon's Nuclear and Thermal Energy Council is formed to ensure that nuclear and coal fired power plants meet health, safety, and environmental standards.
1973	Governor Tom McCall establishes an emergency energy conservation program.
1975	The Oregon Department of Energy is created to support energy conservation and renewable energy, and to conduct state energy planning.
1975	The Energy Facilities Siting Council replaces the Nuclear and Thermal Energy Council.
1977	Oregon's Residential Energy Tax Credit program begins by helping residents invest in solar energy.
1979	The Oregon Department of Energy's Small Scale State Energy Loan Program (SELP) and Business Energy Tax Credit program are passed into law.
1997	Oregon becomes the first state in the country to adopt carbon dioxide emissions performance standards for new energy facilities.
1999	The electric power industry in Oregon is restructured by the legislature in SB 1149. A three percent public purpose charge on electricity bills is established to help fund energy conservation and renewable energy.
1999	The net metering law is passed to allow those with small renewable energy projects to sell excess power back to their electric utility.
2001-2003	The Northwest region adds about 3,350 megawatts of mainly natural-gas fired electricity generation, including 1,675 MW in Oregon.
2001	New state facilities are required to exceed the state energy code by 20 percent.
2005	The Oregon Legislature adopts State appliance energy efficiency standards to eleven products that were not covered by federal standards at that time.
2006	Governor Kulongoski's Executive Order on Sustainability for the 21st Century incorporates greenhouse gas emissions accounting into state agency decisions and reporting. Executive Order

	06-02 calls for the Department of Administrative Services to coordinate an interagency team to lay the foundation for agency greenhouse gas inventories.
2007	The Oregon legislature passes the Renewable Portfolio Standard, passes the Renewable Fuel Standard, and creates the Global Warming Commission.
2007	The governors of five Western states sign a joint memorandum of understanding to form the Western Regional Climate Action Initiative (WCI). The WCI later expanded to other states and most of Canada.
2009	The legislature passed further greenhouse gas reduction efforts. This included SB 101 to prevent construction of new conventional coal plants, HB 2186 to reduce the average carbon intensity of fuels, and HB 2078 that provides incentives for the transition to zero-emission vehicles.
2009	The Legislature creates the Energy Efficiency and Sustainable Technology Program (EEAST) with House Bill 2626. EEAST provides authority to finance residential and commercial energy efficiency and renewable energy projects.
2009	The Oregon Global Warming Commission issued its first report to the legislature.
2011	The Oregon legislature passed the Cool Schools initiative HB 2960.
2011	House Bill 3672 replaced the Business Energy Tax Credit program with three separate credits.
2012	Governor Kitzhaber released a 10-year Energy Action Plan.
2013	The Legislature passes SB 844, a law allowing natural gas utilities to submit voluntary greenhouse gas emission reduction projects for Commission approval.
2013	The legislature passes SB 306 directing the Legislative Revenue Office to prepare a report for the legislature on the feasibility of imposing a clean air fee or tax.

Appendix 3

Federal Activities Summary

American Recovery and Reinvestment Act (ARRA)

Congress enacted and the President signed federal stimulus legislation in February 2009 to help jump-start the economy. The Oregon Department of Energy received several ARRA awards to pass-through during the 2009-11 biennium and additional funding was received by various projects throughout the state totaling $267.5 million.

"Once Though Cooling" - Clean Water Act 316(b)

Section 316(b) of the Clean Water Act requires the U.S. Environmental Protection Agency (EPA) to issue regulations on the design and operation of intake structures, in order to minimize adverse environmental impacts. EPA promulgated regulations in 2001, 2003, 2006, and 2014. The final rule establishes requirements under the Clean Water Act for all existing power generating facilities and existing manufacturing and industrial facilities that withdraw more than 2 million gallons per day of water from "waters of the U.S." and use at least 25 percent of the water they withdraw exclusively for cooling purposes. This rule covers roughly 1,065 existing facilities – 521 of these facilities are factories and the other 544 are power plants.

Mercury and Air Toxics Standards

Until the EPA issued the Mercury and Air Toxics Standards (MATS), there had been no federal standards that require power plants to limit their emissions of toxic air pollutants like mercury, arsenic, and metals. The final rule sets standards for all hazardous air pollutants (HAPs) emitted by coal- and oil-fired electric generating units (EGUs) with a capacity of 25 megawatts or greater. Existing sources generally will have up to four years, if they need it, to comply with MATS. It is anticipated that up to 24 percent of all coal-fired electric power plants in the United States may shut down under pressure to comply with MATS.[1] For Oregon, the EPA claims that these new standards will prevent up to twelve premature deaths, while creating up to $97 million in health benefits in 2016.[2]

Clean Air Act Regional Haze Rules

One of the most common forms of air pollution - haze - degrades visibility in many American cities and scenic areas. Haze is caused when sunlight encounters tiny pollution particles in the air, which reduce the clarity and color of what we see, particularly during humid conditions. The Clean Air Act of 1990 (Title I, Sections 169A and 169B) declared it a national goal to prevent any future, and to remedy any existing, impairment of visibility in 156 mandatory "Class I" Federal areas, the impairment of which results from manmade air pollution. In 1999, the EPA issued regulations for the protection of visibility in Class I National Parks and Wilderness Areas. Revisions to the regional haze rules were promulgated on

[1] EPA, Mercury Air Toxic Standards basic information *available at* http://www.epa.gov/mats/basic.html
[2] EPA, Mercury Air Toxics Standards in Oregon *available at* http://www.epa.gov/airquality/powerplanttoxics/whereyoulive/or.html

July 6, 2005, and October 13, 2006. These regulations require states to establish goals for improving visibility by developing long-term strategies for reducing emissions of air pollutants that cause visibility impairment. The overall goal of the regional haze regulations is to achieve natural background visibility conditions in all Class I areas by the year 2064. The regional haze rule directly affects many of the electric resources that serve Oregon, supplying power from outside our state.

EPA's Clean Air Act Section 111(b) 2013 Proposed Carbon Pollution Standard for New Power Plants

On April 13, 2012, the EPA proposed a new source performance standard for emissions of carbon dioxide from new fossil fuel-fired electric utility generating units. The EPA received more than 2.5 million comments on the proposed rule. After considering information provided in those comments, as well as consideration of continuing changes in the electricity sector, the EPA determined that revisions in its proposed approach are warranted. Thus, in a separate action, the EPA withdrew the April 13, 2012, proposal, and, instead, the EPA proposed new standards of performance for new affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines.

The EPA proposed a separate standard of performance for fossil fuel-fired electric utility steam generating units and integrated gasification combined cycle (IGCC) units that burn coal, petroleum coke, and other fossil fuels that is based on partial implementation of carbon capture and storage as the best system of emission reduction. The EPA also proposed standards for natural gas-fired stationary combustion turbines based on modern, efficient natural gas combined cycle technology as the best system of emission reduction. The EPA proposed a standard of performance for utility boilers and IGCC units based on partial implementation of carbon capture and storage (CCS) as the Best System of Emissions Reduction or BSER. The proposed emission limit for those sources is 1,100 lbs. CO_2/MWh. This action also proposes standards of performance for natural gas-fired stationary combustion turbines based on modern, efficient natural gas combined cycle (NGCC) technology as the BSER. The proposed emission limits for those sources are 1,000 lbs. CO_2/MWh for larger units and 1,100 lbs. CO_2/MWh for smaller units. At this time, the EPA is not proposing standards of performance for modified or reconstructed sources.[3]

EPA's Clean Air Act Section 111(d) Clean Power Plan Proposed Rule

Under the authority of Clean Air Act (CAA) section 111(d), the EPA is proposing emission guidelines for states to follow in developing plans to address greenhouse gas (GHG) emissions from existing fossil fuel-fired electric generating units (EGUs). Nationwide, by 2030, this rule would achieve carbon dioxide emission reductions from the power sector of approximately 30 percent from carbon dioxide emission levels in 2005. The proposal has two main elements: (1) State-specific emission rate-based carbon dioxide goals, and (2) guidelines for the development, submission, and implementation of state plans. To set the state-specific carbon dioxide goals, the EPA analyzed the practical and affordable strategies that states and utilities are already using to lower carbon pollution from the power sector. These strategies include: (1) improvements in efficiency at carbon-intensive power plants, (2) programs that

[3] https://www.federalregister.gov/articles/2014/01/08/2013-28668/standards-of-performance-for-greenhouse-gas-emissions-from-new-stationary-sources-electric-utility

enhance the dispatch priority of low-emitting plants, (3) spur development in renewable power sources, and (4) programs to help homes and businesses use electricity more efficiently. In addition, in calculating each state's carbon dioxide goal, the EPA took into consideration the state's fuel mix, its electricity market, and numerous other factors. Thus, each state's goal reflects its unique conditions. Oregon's EPA set emissions rate goal for 2030 is **372 lbs. of CO_2 per MWh**.

EPA's goal is expressed as a rate of carbon dioxide per megawatt hour of power generated, while greenhouse gas goals are commonly expressed as pounds of carbon dioxide equivalent per megawatt hour produced:

- The average emissions rates in the United States from **natural gas-fired generation: 1,135 lbs./MWh** of carbon dioxide. [4]
- The average emission rates in the United States from **coal-fired generation: 2,249 lbs./MWh** of carbon dioxide.
- The average emissions rates in the United States **from oil-fired generation: 1,672 lbs./MWh** of carbon dioxide.
- Nuclear power plants do not emit carbon dioxide. However, lifecycle cost can be higher depending on the facility and the type of power used by the facility to process the mined uranium to usable fissile material.
- Hydropower's air emissions are negligible because no fuels are burned.
- Biomass power plants emit nitrogen oxide, a small amount of sulfur dioxide, and carbon dioxide.
- Emissions associated with generating electricity from solar technologies are negligible because no fuels are combusted.
- Emissions associated with generating electricity from geothermal technologies are negligible because no fuels are combusted.
- Emissions associated with generating electricity from wind technologies are negligible because no fuels are combusted.

The emissions rate goal of 372 lbs./MWh set by EPA for Oregon is well below the average fossil fuel natural gas fired power plant emissions rate of 1,135 lbs./MWh. Oregon could reach its rate goal by averaging the emissions from the types of resources that meet Oregon's' electric demand. This is done by assigning emissions mitigation credit to renewable generation and energy efficiency.

The investor owned electric generating utilities (IOUs) will be running 111(d) compliance scenario's in their 2015 Integrated Resource Plans. The modeling conducted by the IOUs will inform the PUC and the state about how each utility will mitigate their carbon intensity. At that time, the PUC will be able to evaluate how much closer the requirements of 111(d) will move the state toward meeting the state's greenhouse gas goals. PUC staff has been working closely with other Oregon state agencies on the federal 111(d) rulemaking.

[4] http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.html