e-FILING REPORT COVER SHEET

REPORT NAME: Biennial Greenhouse Gas Emissions Rate Impact Report

COMPANY NAME: Pacific Power

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☐ No ☒ Yes

If yes, please submit only the cover letter electronically. Submit confidential information as directed OAR 860-001-0070 or the terms of an applicable protective order.

If known, please select designation: ☒ RE (Electric) ☐ RG (Gas) ☐ RW (Water) ☐ RO (Other)

Report is required by: ☒ OAR 860-085-0050
☐ Statute
☐ Order
☐ Other

Is this report associated with a specific docket/case? ☒ No ☐ Yes

If Yes, enter docket number:

Key words: Biennial Greenhouse Gas Emissions Rate Impact

If known, please select the PUC Section to which the report should be directed:

☐ Corporate Analysis and Water Regulation

☐ Economic and Policy Analysis

☐ Electric and Natural Gas Revenue Requirements

☒ Electric Rates and Planning

☐ Natural Gas Rates and Planning

☐ Utility Safety, Reliability & Security

☐ Administrative Hearings Division

☐ Consumer Services Section

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PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

July 13, 2012

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
550 Capitol Street NE, Suite 215
Salem, OR 97301-2551

Attention: Filing Center

Re: Biennial Greenhouse Gas Emissions Rate Impact Report

Pursuant to OAR 860-085-0050, PacifiCorp d.b.a. Pacific Power (Company) hereby submits for filing its Biennial Greenhouse Gas Emissions Rate Impact Report.

Pursuant to OAR 860-085-0005(2), the Company requested that the Oregon Public Utility Commission (Commission) waive the July 1, 2012 deadline and allow the Company to file its report on July 13, 2012. On July 2, 2012, the Commission granted the Company's request for a waiver in Order No. 12-270.

The confidential information in this report is provided under separate cover per OAR 860-001-0070.

It is respectfully requested that all formal data requests regarding this filing be addressed to:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, Oregon 97232

Informal inquiries regarding this filing may be directed to Bryce Dalley at (503) 813-6389.

Sincerely,

William R. Griffith /RBD

William R. Griffith
Vice President, Regulation

Enclosures

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Rate Impacts of Meeting Oregon SB 101 Carbon Dioxide Emission Goals

July 13, 2012

STUDY DESIGN

This analysis used PacifiCorp's capacity expansion optimization model, System Optimizer, to develop two resource portfolios that result in reductions of CO_2 emissions: 10 percent below 1990 levels by 2020 and 15 percent below 2005 levels by 2020. To develop these two portfolios, the System Optimizer model was set up with hard annual CO_2 emissions caps that constrain the model to solve for the least-cost resource expansion plan that does not exceed the physical CO_2 emission limits in each year of the simulation. Portfolio costs from the System Optimizer model studies were used in a full revenue requirement model to calculate rate impact measures.

PacifiCorp modified the portfolio from the Company's 2011 Integrated Resource Plan Update (2011 IRP Update) to develop a base portfolio. To reflect coal plant investment assumptions incorporated in recent state regulatory filings, both the base portfolio and CO_2 emission reduction portfolios assume that Carbon units 1 and 2 in Utah retire in 2015 and that the Naughton 3 coal unit is converted to burn natural gas in 2015. The emission reduction assumptions do not anticipate other coal plant retirements during the 10-year period covered by this study or the acquisition of resources that are not currently commercially or financially available.[1] Expansion options available in the base case and two scenarios are the same as those used in the development of the 2011 IRP update portfolio. To account for market price and load forecasts used for the study, the System Optimizer model was allowed to optimize selections of demand side management (DSM) and firm market purchases for each of the three portfolios.

[1] Instructions from Oregon commission staff: "to the extent feasible, the compliance resource portfolio assumed in the analysis should be reasonable, in that the assumed technologies (or changes to the existing system) should be commercially, regulatorily and financially viable (i.e. no silver bullets)."

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ASSUMPTIONS

Table 1 presents descriptions of primary study assumptions.

Table 1. Study Assumptions

Assumption	Base Case	Hard Cap Scenarios	Comments
Revenue requirement forecast	[redacted]		
Oregon customer forecast	2012 business plan annual forecast of average Oregon customers 2012 559,718 2013 562,898 2014 566,011 2015 568,986 2016 571,758 2017 574,329 2018 576,729 2019 578,974 2020 581,069		
CO_2: 1990 baseline emissions	N/A	• Owned generation uses 1990 PacifiCorp CO_2 direct emissions baseline value. • CO2 emissions associated with market purchases have an emission factor of 900 lbs/MWh.	1990 CO_2 direct emissions baseline accounts for sale of Centralia and changes in other ownership positions. Emission factor for market purchases reflects Oregon commission staff study preparation guidelines.

[2] The 2012 business plan was finalized in the fall of 2011.

<table>
<tr><th>Assumption</th><th>Base Case</th><th>Hard Cap Scenarios</th><th>Comments</th></tr>
<tr><td>CO_2: 2005 baseline emissions</td><td>N/A</td><td>• Emissions for owned generation and purchases from 2005 California Climate Action Registry (CCAR) filing.
• CO2 emissions associated with market purchases have an emission factor of 900 lbs/MWh.</td><td></td></tr>
<tr><td>CO_2: yearly emissions targets</td><td>None</td><td>Modeled as annual emission limits starting 2012.
Annual Emission Limits
(thousands of tons)
<table>
<tr><th>Year</th><th>Scenario 1</th><th>Scenario 2</th></tr>
<tr><td>2012</td><td>57,374</td><td>57,374</td></tr>
<tr><td>2013</td><td>55,813</td><td>56,677</td></tr>
<tr><td>2014</td><td>54,253</td><td>55,980</td></tr>
<tr><td>2015</td><td>52,692</td><td>55,283</td></tr>
<tr><td>2016</td><td>51,132</td><td>54,587</td></tr>
<tr><td>2017</td><td>49,571</td><td>53,890</td></tr>
<tr><td>2018</td><td>48,011</td><td>53,193</td></tr>
<tr><td>2019</td><td>46,450</td><td>52,496</td></tr>
<tr><td>2020</td><td>44,890</td><td>51,800</td></tr>
</table></td><td>2012 starting value for scenarios is the sum of generator and purchases emissions from base case study.

Yearly targets represent a linear reduction from 2012 values to the 2020 target.
• Scenario 1 is based on Oregon HB 3543 emission level targets (10 percent below 1990 levels).
• Scenario 2 reflects Western Climate Initiative (WCI) emission targets (15 percent below 2005 levels).</td></tr>
<tr><td>Existing and expansion resources</td><td colspan="2">Existing and expansion resources have CO_2 emission assumptions specific to the particular technology of each resource.</td><td></td></tr>
<tr><td>Market sales and purchases</td><td colspan="2">Market sales and purchases have a CO_2 emission rate of 900 lbs/MWh.
Market purchase emissions apply toward the cap.
Market sales caps from the 2011 IRP Update Coal Study Update are used in the base study. The two scenarios also start with the same sales limits in 2012 but linearly decline to zero by 2018.</td><td>Sales limits applied on the assumption made that sellers will require buyers to take on risk of coal CO_2 emissions under a hard cap scenario</td></tr>
</table>

STUDY RESULTS

Full Revenue Requirement Impacts

Table 2 presents the rate impacts on a year-by-year and total 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 source for the full revenue requirement is the baseline forecast prepared for the 2012 Business Plan. Table 3 provided the rate impacts for Oregon based on system generation factors as well as on a per-customer basis. The Oregon system generation factors also come from the 2012 Business Plan. Appendix A provides a line item breakdown of portfolio costs from the System Optimizer model. Note that these rate impacts do not include costs associated with failing to meet minimum-take provisions in the Company's coal supply contracts.

Table 2. Annual and Cumulative System Percentage Rate Impacts

	Scenario 1 (90% of 1990)	**Scenario 2** (85% of 2005)
Year	**Yearly percent difference from Base case**	**Yearly percent difference from Base**
2012	0.1%	0.1%
2013	0.3%	0.2%
2014	0.7%	0.3%
2015	0.4%	0.1%
2016	0.9%	0.4%
2017	1.2%	0.7%
2018	2.0%	1.5%
2019	0.6%	-0.1%
2020	1.5%	0.9%
Sum	**7.6%**	**4.0%**

Table 3. Annual and Cumulative Dollar Rate Impacts per Average Oregon Customer

	Scenario 1 (90% of 1990)	Scenario 2 (85% of 2005)
Year	Yearly rate impact per average Oregon customer (dollars)	Yearly rate impact per average Oregon customer (dollars)
2012	1.93	1.13
2013	6.42	3.71
2014	14.79	7.32
2015	7.64	1.23
2016	19.59	9.63
2017	28.43	16.34
2018	50.11	37.58
2019	16.90	-3.17
2020	38.45	21.53
Sum	**184.25**	**95.31**

Portfolio Resource Selection and Utilization

Tables 4 through 6 report the resources in each of the three portfolios (Base, Scenario 1, and Scenario 2). Tables 7 and 8 show the year-to-year differences and the nine-year totals of differences in resources for Scenarios 1 and 2 relative to the Base.

Model results show that the CO_2 emissions reduction goals for Scenarios 1 and 2 are met largely through changes in the dispatch of existing and expansion resources along with the acquisition of DSM resources. Beyond the fixed 2014 and 2016 combined cycle combustion turbine (CCCT) resources, a new 'G'-class 1x1 CCCT in Utah is selected in all portfolios except that in Scenario 1, the resource is selected in 2019 rather than 2020. No incremental wind resources above those in the base were selected in either of the two scenarios.

Coal and gas units are dispatched economically by the model subject to the system-wide CO_2 emission constraints. As expected, average coal unit capacity factors are lower in the scenario studies than in the base study. Table 9 shows simple average annual capacity factors for coal resources and CCCT resources.

Table 4. Base Resource Portfolio

Base

		Resource Addition Capacity (MW)									Resource Total
	Resource	2012	2013	2014	2015	2016	2017	2018	2019	2020	9-year
East											
	Naughton 3 - Gas re-fuel	-	-	-	338	-	-	-	-	-	338
	CCCT F 2x1 (Utah North, Utah South)	-	-	637	-	597	-	-	-	-	1,234
	CCCT GH 1x1 (Utah South)	-	-	-	-	-	-	-	393	-	393
	Utah Capacity Purchase	-	-	-	-	-	-	-	-	-	-
	Coal Plant Turbine Upgrades	18.9	1.8	-	-	-	-	-	-	-	21
	Wind, Wyoming, 35% capacity factor	-	-	-	-	-	-	225	225	-	450
	Total Wind	-	-	-	-	-	-	225	225	-	450
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	9
	DSM, Class 1, Idaho-DLC-Irrigation	-	-	-	20	-	-	-	-	-	20
	DSM, Class 1, Utah-Curtailment	-	-	-	71	-	-	-	-	-	71
	DSM, Class 1, Utah-DLC-Residential	-	-	-	50	-	-	-	-	-	50
	DSM, Class 1 Total	-	-	-	141	-	-	-	-	-	141
	DSM, Class 2, Idaho	0	2	3	3	-	3	3	3	5	21
	DSM, Class 2, Utah	43	34	35	36	7	40	41	43	45	323
	DSM, Class 2, Wyoming	1	-	5	6	-	-	8	8	8	35
	DSM, Class 2 Total	43	36	43	45	7	43	51	53	57	379
	FOT Mead Q3 HLH	95	115	65	88	52	-	-	-	-	
	FOT Mona-3 Q3 HLH	-	-	300	300	93	184	300	296	300	
	FOT Mona-4 Q3 HLH	-	150	-	-	-	-	-	-	-	
West											
	Coal Plant Turbine Upgrades	-	12.0	-	-	-	-	-	-	-	12
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	38
	DSM, Class 1, Washington-DLC-Residential	-	-	-	5	-	-	-	-	-	5
	DSM, Class 1, Washington-DLC-Irrigation	-	-	-	9	-	-	-	-	-	9
	DSM, Class 1, Oregon-Curtailment	-	-	-	36	-	-	-	-	-	36
	DSM, Class 1, Oregon-DLC-Residential	-	-	-	-	-	-	-	7	-	7
	DSM, Class 1, Oregon-DLC-Water heat	-	-	-	4	-	-	-	-	-	4
	DSM, Class 1, Oregon-DLC-Irrigation	-	-	-	13	-	-	-	-	-	13
	DSM, Class 1, CA-DLC-Irrigation	-	-	-	5	-	-	-	-	-	5
	DSM, Class 1 Total	-	-	-	72	-	-	-	7	-	78
	DSM, Class 2, California	0	1	1	1	-	1	1	1	1	7
	DSM, Class 2, Oregon	43	46	50	50	48	47	39	41	41	405
	DSM, Class 2, Washington	8	8	8	8	7	8	8	8	8	70
	DSM, Class 2 Total	51	54	58	58	56	56	48	50	50	482
	Oregon Solar Cap Standard	2	2	2	3	-	-	-	-	-	9
	Oregon Solar Pilot	2	2	1	-	-	-	-	-	-	6
	FOT COB Q3 HLH	400	400	400	392	342	342	342	342	342	
	FOT NOB Q3 HLH	100	100	100	100	100	100	100	100	100	
	FOT Mid-Columbia Flat	72	-	377	400	375	376	385	195	400	
	FOT Mid-Columbia Q3 HLH	400	400	400	400	400	400	400	400	400	
	FOT Mid-Columbia Q3 HLH, price premium	375	372	-	-	-	-	-	-	-	
	Annual Additions, Long Term Resources	123	113	747	663	665	104	329	733	113	
	Annual Additions, Short Term Resources	1,442	1,536	1,642	1,680	1,362	1,401	1,526	1,333	1,542	
	Total Annual Additions	1,565	1,649	2,389	2,343	2,027	1,505	1,856	2,065	1,654	

Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

Table 5. Scenario 1 Portfolio

Scenario 1 - 90% of 1990 CO_2 emissions

	Resource	Resource Addition Capacity (MW) 2012	2013	2014	2015	2016	2017	2018	2019	2020	Resource Total 9-year
East											
	Naughton 3 - Gas re-fuel	-	-	-	338	-	-	-	-	-	338
	CCCT F 2x1 (Utah North, Utah South)	-	-	637	-	597	-	-	-	-	1,234
	CCCT GH 1x1 (Utah South)	-	-	-	-	-	-	-	-	393	393
	Utah Capacity Purchase	-	-	-	-	-	-	-	-	-	-
	Coal Plant Turbine Upgrades	18.9	1.8	-	-	-	-	-	-	-	21
	Wind, Wyoming, 35% capacity factor	-	-	-	-	-	-	225	225	-	450
	Total Wind	-	-	-	-	-	-	225	225	-	450
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	9
	DSM, Class 1, Idaho-DLC-Irrigation	-	-	20	-	-	-	-	-	-	20
	DSM, Class 1, Utah-Curtailment	-	-	-	71	-	-	-	-	-	71
	DSM, Class 1, Utah-DLC-Residential	-	-	-	4	-	-	14	67	-	85
	DSM, Class 1 Total	-	-	20	76	-	-	14	67	-	176
	DSM, Class 2, Idaho	2	2	3	4	4	5	5	5	5	34
	DSM, Class 2, Utah	47	39	40	41	46	47	48	51	50	410
	DSM, Class 2, Wyoming	4	5	6	6	7	8	9	9	9	63
	DSM, Class 2 Total	53	46	49	51	57	60	62	65	64	507
	FOT Mead Q3 HLH	66	79	168	88	88	-	-	-	-	
	FOT Mona-3 Q3 HLH	-	-	300	300	300	300	300	300	300	
	FOT Mona-4 Q3 HLH	-	150	-	-	-	-	-	-	-	
West											
	Coal Plant Turbine Upgrades	-	12.0	-	-	-	-	-	-	-	12
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	38
	DSM, Class 1, Washington-DLC-Residential	-	-	-	5	-	-	-	-	-	5
	DSM, Class 1, Washington-DLC-Irrigation	-	-	-	9	-	-	-	-	-	9
	DSM, Class 1, Oregon-Curtailment	-	-	-	36	-	-	-	-	-	36
	DSM, Class 1, Oregon-DLC-Water heat	-	-	-	4	-	-	-	-	-	4
	DSM, Class 1, Oregon-DLC-Irrigation	-	-	-	13	-	-	-	-	-	13
	DSM, Class 1, CA-DLC-Irrigation	-	-	-	5	-	-	-	-	-	5
	DSM, Class 1 Total	-	-	-	72	-	-	-	-	-	72
	DSM, Class 2, California	1	1	1	1	1	2	2	2	2	12
	DSM, Class 2, Oregon	45	47	61	62	61	60	52	52	52	492
	DSM, Class 2, Washington	8	8	8	8	8	8	9	9	8	74
	DSM, Class 2 Total	53	56	70	71	70	70	63	63	62	578
	Oregon Solar Cap Standard	2	2	2	3	-	-	-	-	-	9
	Oregon Solar Pilot	2	2	1	-	-	-	-	-	-	6
	FOT COB Q3 HLH	400	400	400	392	342	342	342	342	342	
	FOT NOB Q3 HLH	100	100	100	100	100	100	100	100	100	
	FOT Mid-Columbia Flat	72	-	213	400	89	204	306	400	245	
	FOT Mid-Columbia Q3 HLH	400	400	400	400	400	400	400	400	400	
	FOT Mid-Columbia Q3 HLH, price premium	375	371	-	-	-	-	-	-	-	
	Annual Additions, Long Term Resources	134	125	784	616	729	135	369	425	525	
	Annual Additions, Short Term Resources	1,413	1,500	1,581	1,680	1,319	1,345	1,448	1,542	1,386	
	Total Annual Additions	1,548	1,625	2,365	2,296	2,049	1,480	1,816	1,967	1,911	

Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

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Table 6. Scenario 2 Portfolio

Scenario 2 - 85% of 2005 CO_2 emissions

	Resource Addition Capacity (MW)									Resource Totals
Resource	2012	2013	2014	2015	2016	2017	2018	2019	2020	9-year
East										
Naughton 3 - Gas re-fuel	-	-	-	338	-	-	-	-	-	338
CCCT F 2x1 (Utah North, Utah South)	-	-	637	-	597	-	-	-	-	1,234
CCCT GH 1x1 (Utah South)	-	-	-	-	-	-	-	393	-	393
Utah Capacity Purchase	-	-	-	-	-	-	-	-	-	-
Coal Plant Turbine Upgrades	18.9	1.8	-	-	-	-	-	-	-	21
Wind, Wyoming, 35% capacity factor	-	-	-	-	-	-	225	225	-	450
Total Wind	-	-	-	-	-	-	225	225	-	450
CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	9
DSM, Class 1, Idaho-DLC-Irrigation	-	-	20	-	-	-	-	-	-	20
DSM, Class 1, Utah-Curtailment	-	-	-	71	-	-	-	-	-	71
DSM, Class 1, Utah-DLC-Residential	-	-	-	24	-	-	-	-	-	24
DSM, Class 1 Total	-	-	20	95	-	-	-	-	-	115
DSM, Class 2, Idaho	1	2	3	3	4	4	4	4	5	31
DSM, Class 2, Utah	43	34	35	41	39	45	46	48	50	381
DSM, Class 2, Wyoming	1	5	5	6	6	7	8	8	9	54
DSM, Class 2 Total	45	40	43	50	49	56	58	60	64	466
FOT Mead Q3 HLH	76	92	168	88	60	-	-	-	-	
FOT Mona-3 Q3 HLH	-	-	300	300	300	300	300	300	300	
FOT Mona-4 Q3 HLH	-	150	-	-	-	-	-	-	-	
West										
Coal Plant Turbine Upgrades	-	12.0	-	-	-	-	-	-	-	12
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	38
DSM, Class 1, Washington-DLC-Residential	-	-	-	5	-	-	-	-	-	5
DSM, Class 1, Washington-DLC-Irrigation	-	-	-	9	-	-	-	-	-	9
DSM, Class 1, Oregon-Curtailment	-	-	-	36	-	-	-	-	-	36
DSM, Class 1, Oregon-DLC-Water heat	-	-	-	4	-	-	-	-	-	4
DSM, Class 1, Oregon-DLC-Irrigation	-	-	-	13	-	-	-	-	-	13
DSM, Class 1, CA-DLC-Irrigation	-	-	-	5	-	-	-	-	-	5
DSM, Class 1 Total	-	-	-	72	-	-	-	-	-	72
DSM, Class 2, California	1	1	1	1	1	1	1	1	2	10
DSM, Class 2, Oregon	43	46	50	51	50	49	52	52	52	446
DSM, Class 2, Washington	8	8	8	8	7	8	8	8	8	70
DSM, Class 2 Total	52	54	58	60	58	58	62	62	62	526
Oregon Solar Cap Standard	2	2	2	3	-	-	-	-	-	9
Oregon Solar Pilot	2	2	1	-	-	-	-	-	-	6
FOT COB Q3 HLH	400	400	400	392	342	342	342	342	342	3,300
FOT NOB Q3 HLH	100	100	100	100	100	100	100	100	100	900
FOT Mid-Columbia Flat	72	-	232	400	125	214	333	140	343	1,859
FOT Mid-Columbia Q3 HLH	400	400	400	400	400	400	400	400	400	3,600
FOT Mid-Columbia Q3 HLH, price premium	375	372	-	-	-	-	-	-	-	747
Annual Additions, Long Term Resources	125	118	767	624	710	119	350	745	132	
Annual Additions, Short Term Resources	1,423	1,514	1,600	1,680	1,326	1,355	1,475	1,282	1,485	
Total Annual Additions	1,548	1,631	2,367	2,304	2,036	1,475	1,825	2,027	1,617	

Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

Table 7. Resource Differences, Scenario 1 Portfolio minus Base Portfolio

Scenario 1 minus Base

	Resource	Resource Addition Capacity (MW)									Resource totals
	Resource	2012	2013	2014	2015	2016	2017	2018	2019	2020	9-year
East											
	CCCT GH 1x1 (Utah South)	-	-	-	-	-	-	-	(393)	393	-
	Total Wind	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Idaho, DLC-Irrigation	-	-	19.8	(19.8)	-	-	-	-	-	-
	DSM, Class 1, Utah, DLC-Residential	-	-	-	(45.9)	-	-	13.7	66.8	-	35
	DSM, Class 1 & 3 Total	-	-	19.8	(65.7)	-	-	13.7	66.8	-	35
	DSM, Class 2, Idaho	1.7	0.1	0.2	0.2	4.2	2.0	2.2	2.3	0.5	13
	DSM, Class 2, Utah	4.0	5.2	5.0	5.0	38.5	7.1	7.3	8.9	5.4	86
	DSM, Class 2, Wyoming	3.6	4.5	0.6	0.7	7.1	7.9	1.1	1.3	1.2	28
	DSM, Class 2 Total	9.3	9.8	5.8	5.9	49.8	17.0	10.6	12.6	7.1	128
	FOT Mead Q3 HLH	(29)	(36)	103	-	36	-	-	-	-	
	FOT Mona/Nevada Utah Border	-	-	-	-	207	116	-	4	-	
West											
	Total Wind	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Oregon, DLC-Residential	-	-	-	-	-	-	-	(6.8)	-	(7)
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	(6.8)	-	(7)
	DSM, Class 2, California	0.6	0.2	0.3	0.3	1.4	0.6	0.7	0.6	0.5	5
	DSM, Class 2, Oregon	1.4	1.6	10.8	12.1	12.5	13.1	13.1	11.3	11.3	87
	DSM, Class 2, Washington	-	0.4	0.3	0.3	0.4	0.4	1.3	1.0	0.1	4
	DSM, Class 2 Total	2.0	2.1	11.3	12.8	14.3	14.1	15.0	12.9	11.9	96
	FOT COB Q3 HLH	-	-	-	-	-	-	-	-	-	
	FOT Mid Columbia Flat	-	-	(164)	-	(285)	(172)	(79)	205	(155)	
	FOT Mid-Columbia Q3 HLH	-	-	-	-	-	-	-	-	-	
	FOT Mid-Columbia Q3 HLH, price premium	-	(0)	-	-	-	-	-	-	-	
	Annual Additions, Long Term Resources	11	12	37	(47)	64	31	39	(307)	412	
	Annual Additions, Short Term Resources	(29)	(36)	(61)	-	(42)	(56)	(79)	209	(155)	
	Total Annual Additions	(17)	(24)	(24)	(47)	22	(25)	(39)	(99)	257	

Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

Table 8. Resource Differences, Scenario 2 Portfolio minus Base Portfolio

Scenario 2 minus Base

	Resource	Resource Addition Capacity (MW)									Resource totals
	Resource	2012	2013	2014	2015	2016	2017	2018	2019	2020	9-year
East											
	Total Wind	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Idaho, DLC-Irrigation	-	-	19.8	(19.8)	-	-	-	-	-	-
	DSM, Class 1, Utah, DLC-Residential	-	-	-	(26.2)	-	-	-	-	-	(26)
	DSM, Class 1 & 3 Total	-	-	19.8	(46.0)	-	-	-	-	-	(26)
	DSM, Class 2, Idaho	1.1	-	-	-	3.9	1.6	1.6	1.6	0.5	10
	DSM, Class 2, Utah	-	-	-	5.0	31.4	5.2	5.3	5.3	5.4	58
	DSM, Class 2, Wyoming	-	4.5	-	-	6.3	6.9	-	-	1.2	19
	DSM, Class 2 Total HLH	1.1	4.5	-	5.0	41.5	13.7	6.9	6.9	7.1	87
	FOT Mead Q3	(19)	(22)	103	-	8	-	-	-	-	
	FOT Mona/Nevada Utah Border	-	-	-	-	207	116	-	4	-	
West											
	Total Wind	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, Oregon, DLC-Residential	-	-	-	-	-	-	-	(6.8)	-	(7)
	DSM, Class 1 & 3 Total	-	-	-	-	-	-	-	(6.8)	-	(7)
	DSM, Class 2, California	0.5	-	-	-	1.0	-	0.5	0.5	0.5	3
	DSM, Class 2, Oregon	-	-	-	1.8	1.8	1.8	13.1	11.3	11.3	41
	DSM, Class 2, Washington	-	-	-	-	-	0.3	0.4	0.1	0.1	1
	DSM, Class 2 Total	0.5	-	-	1.8	2.8	2.0	13.9	11.8	11.9	45
	FOT Mid Columbia Flat	-	-	(145)	-	(250)	(162)	(52)	(55)	(57)	
	FOT MidColumbia Q3 HLH	-	-	-	-	-	-	-	-	-	
	Annual Additions, Long Term Resources	2	5	20	(39)	44	16	21	12	19	
	Annual Additions, Short Term Resources	(19)	(22)	(42)	-	(35)	(46)	(52)	(51)	(57)	
	Total Annual Additions	(18)	(18)	(22)	(39)	9	(30)	(31)	(39)	(38)	

Front office transaction and growth resource amounts reflect one-year transaction periods, and are not additive.

Table 9. Average Annual Capacity Factors for Coal and Gas Resources (%)

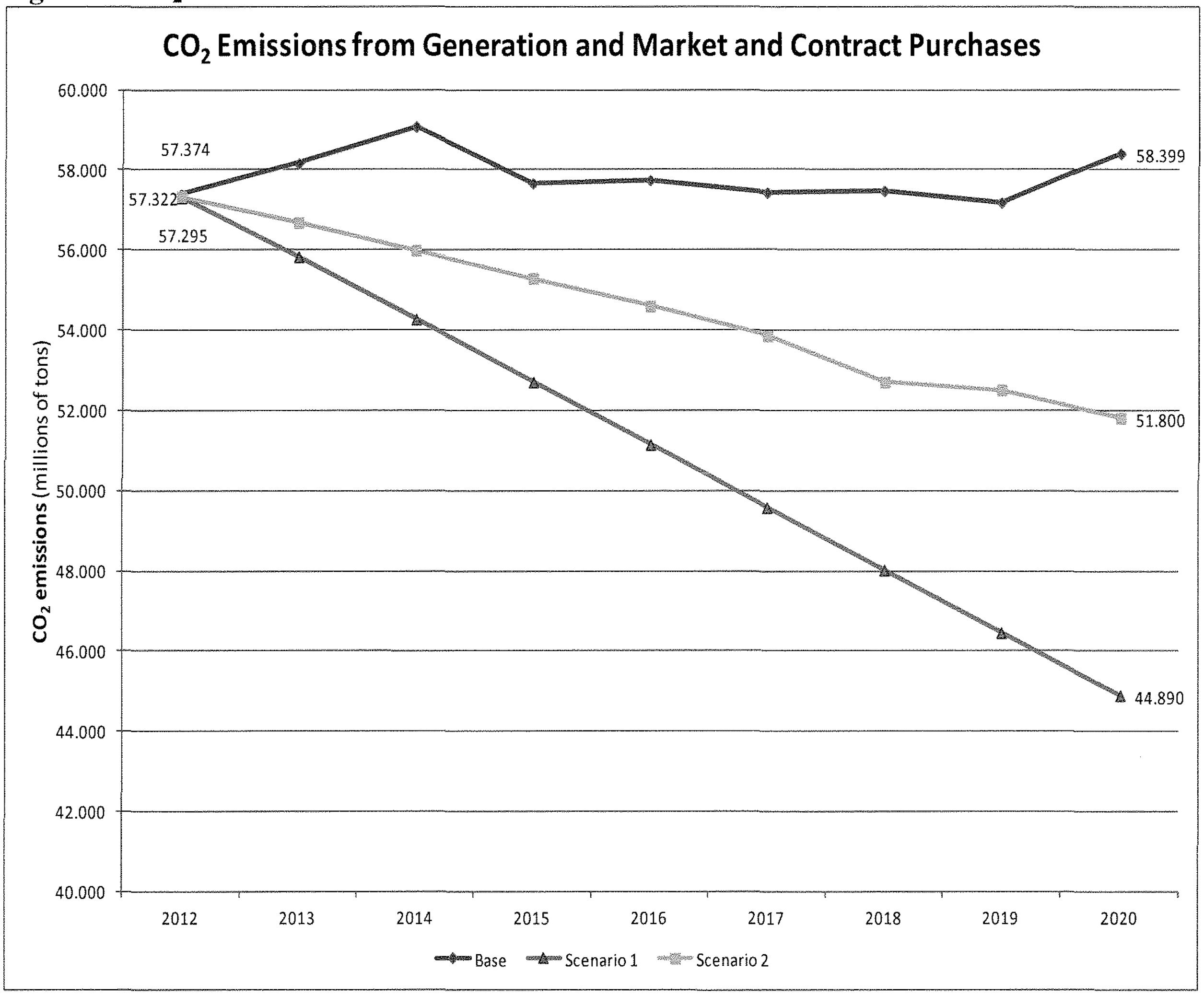
Coal Resources	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base	85.4	86.3	87.9	90.1	90.6	89.9	91.0	91.2	91.5
Scenario 1	85.4	83.2	80.4	81.5	78.0	74.1	72.4	67.4	61.3
Scenario 2	85.4	85.0	84.2	88.8	89.8	89.1	90.1	89.2	83.8

CCCT resources	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base	34.8	38.4	38.9	36.6	32.4	33.7	35.0	30.0	33.1
Scenario 1	34.6	31.2	23.8	22.9	22.3	21.2	22.1	27.1	35.0
Scenario 2	34.6	32.9	29.1	25.5	20.5	18.4	13.0	14.9	16.6

Carbon Dioxide Emissions

For portfolio development, the annual emission reduction levels serve as upper-bound constraints on the sum of emissions from generators and market and contract purchases. CO_2 emissions equal the input cap levels in every year. Figure 1 shows the CO_2 emission levels for the base case and CO_2 reduction scenarios. Credits from sales of owned generation are not shown.

Figure 1. CO_2 Emissions



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Appendix A

Scenario PVRR Costs and Comparisons to the Base (System Optimizer Model Output)

9-year PVRR @ 7.15%

Cost Components (millions)	Base	Scenario 1	Scenario 2
Existing Station Fuel Costs	$ 6,584	$ 5,328	$ 5,767
Existing Station Variable O&M Costs	$ 671	$ 567	$ 607
Existing Station Emission Costs	$ -	$ -	$ -
Existing Station Dispatch Adder Costs	$ -	$ -	$ -
Existing Station Fixed Costs	$ 3,318	$ 3,318	$ 3,318
Existing Station Decomm. Costs	$ -	$ -	$ -
Proposed Station Fuel Costs	$ 982	$ 989	$ 650
Proposed Station Variable O&M Costs	$ 1,572	$ 1,400	$ 1,343
Proposed Station Emission Costs	$ -	$ -	$ -
Proposed Station Dispatch Adder Costs	$ -	$ -	$ -
Proposed Station Fixed Costs	$ 275	$ 270	$ 276
Proposed Station Capital Costs	$ 771	$ 747	$ 771
Station Total Costs	**$ 14,173**	**$ 12,619**	**$ 12,731**
Existing Transmission Variable Costs	$ 9	$ 3	$ 4
Existing Transmission Fixed Costs	$ -	$ -	$ -
Proposed Transmission Variable Costs	$ -	$ -	$ -
Proposed Transmission Fixed Costs	$ -	$ -	$ -
Proposed Transmission Capital Costs	$ 321	$ 321	$ 321
Transmission Total Costs	**$ 330**	**$ 324**	**$ 325**
Existing DSM Program Energy Costs	$ -	$ -	$ -
Existing DSM Program Capacity Costs	$ 136	$ 136	$ 136
Proposed DSM Program Energy Costs	$ 592	$ 803	$ 718
Proposed DSM Program Capacity Costs	$ 72	$ 63	$ 60
Proposed DSM Program Capital Costs	$ 6	$ 6	$ 5
DSM Program Total Costs	**$ 806**	**$ 1,008**	**$ 920**
Existing Contract Energy Costs	$ 1,449	$ 1,449	$ 1,445
Existing Contract Capacity Costs	$ 25	$ 25	$ 25
Existing Contract Premium Costs	$ -	$ -	$ -
Proposed Contract Energy Costs	$ -	$ -	$ -
Proposed Contract Capacity Costs	$ -	$ -	$ -
Proposed Contract Premium Costs	$ -	$ -	$ -
Contract Total Costs	**$ 1,475**	**$ 1,474**	**$ 1,470**
Spot Onpeak Purchase Costs	$ 93	$ 84	$ 82
Spot Offpeak Purchase Costs	$ 407	$ 524	$ 241
Spot Onpeak Sale Revenues	$ 2,127	$ 814	$ 930
Spot Offpeak Sale Revenues	$ 1,301	$ 367	$ 482
Spot Net Purchase Costs	**$ (2,928)**	**$ (574)**	**$ (1,090)**
Unserved Energy Costs	$ -	$ -	$ -
Unserved Capacity Costs	$ -	$ -	$ -
Unserved Total Costs	**$ -**	**$ -**	**$ -**
Total Costs	**$ 13,857**	**$ 14,852**	**$ 14,356**

Difference of 9-year PVRR @ 7.15% (Scenario minus Base)

Cost Components (millions)	**Scenario 1**	**Scenario 2**
Existing Station Fuel Costs	$ (1,256)	$ (818)
Existing Station Variable O&M Costs	$ (104)	$ (64)
Existing Station Emission Costs	$ -	$ -
Existing Station Dispatch Adder Costs	$ -	$ -
Existing Station Fixed Costs	$ -	$ -
Existing Station Decomm. Costs	$ -	$ -
Proposed Station Fuel Costs	$ 7	$ (333)
Proposed Station Variable O&M Costs	$ (171)	$ (229)
Proposed Station Emission Costs	$ -	$ -
Proposed Station Dispatch Adder Costs	$ -	$ -
Proposed Station Fixed Costs	$ (5)	$ 1
Proposed Station Capital Costs	$ (24)	$ -
Station Total Costs	**$ (1,554)**	**$ (1,442)**
Existing Transmission Variable Costs	$ (6)	$ (6)
Existing Transmission Fixed Costs	$ -	$ -
Proposed Transmission Variable Costs	$ -	$ -
Proposed Transmission Fixed Costs	$ -	$ -
Proposed Transmission Capital Costs	$ -	$ -
Transmission Total Costs	**$ (6)**	**$ (6)**
Existing DSM Program Energy Costs	$ -	$ -
Existing DSM Program Capacity Costs	$ -	$ -
Proposed DSM Program Energy Costs	$ 212	$ 126
Proposed DSM Program Capacity Costs	$ (10)	$ (12)
Proposed DSM Program Capital Costs	$ (1)	$ (1)
DSM Program Total Costs	**$ 201**	**$ 113**
Existing Contract Energy Costs	$ (1)	$ (4)
Existing Contract Capacity Costs	$ -	$ -
Existing Contract Premium Costs	$ -	$ -
Proposed Contract Energy Costs	$ -	$ -
Proposed Contract Capacity Costs	$ -	$ -
Proposed Contract Premium Costs	$ -	$ -
Contract Total Costs	**$ (1)**	**$ (4)**
Spot Onpeak Purchase Costs	$ (9)	$ (11)
Spot Offpeak Purchase Costs	$ 117	$ (166)
Spot Onpeak Sale Revenues	$ (1,312)	$ (1,196)
Spot Offpeak Sale Revenues	$ (934)	$ (819)
Spot Net Purchase Costs	**$ 2,354**	**$ 1,838**
Unserved Energy Costs	$ -	$ -
Unserved Capacity Costs	$ -	$ -
Unserved Total Costs	**$ -**	**$ -**
Total Costs	**$ 995**	**$ 499**