OREGON DEPARTMENT OF ENERGY

ENERGY FACILITY SIT

2018 Rulemaking

Carbon Dioxide Standards, Phase Two: Update CO2 Standards

RAC Input Received as of May 7, 2018

PacifiCorp

Email Dated 5/4/2018

SIERMAN Jason * ODOE

From:	Heng, Irene <Irene.Heng@pacificorp.com>
Sent:	Friday, May 4, 2018 11:38 AM
To:	SIERMAN Jason * ODOE
Cc:	Teply, Chad; Wilkeson, Laura; Bice, Jordan; Till, Dustin; Wiencke, Mary
Subject:	Comments for Analysis for EFSC CO2 Standards Reset
Attachments:	EFSC CO2 Analyis of 13 Principles 2018-04-10(draft)_IH.pdf

Jason,

I have reviewed the documents you had provided and am returning one document with comments/numerical adjustments attached above in addition to some higher level observations noted below.

Please find comments from the review of the documents as follows:

- The Grand River Dam Authority (GRDA) unit has a full year of actual data in 2017 reported in the EPA's acid rain program database and it did not hit the 6,333 btu/kWh heat rate. In 2017, calculated from the Gross output and CO2 Short tons emitted, and heat Input reported, the unit's actual heat rate was 6,693 btu/kWh.
- There is no way for any of the RAC members to verify the 6,333 btu/kWh heat rate as it is from unit performance test data where the reports are confidential to GRDA and Mitsubishi unless ODOE has the ability to share the test report and calculations that show the ISO conditions while taking into consideration an Oregon site. Not being able to verify the calculations of the 6,333 and being able to observe an actual operations heat rate, my recommend would have been to go with actual observed heat rate to set the CO2 standard where it is actually verifiable by all parties.
- There are miscellaneous miscalculations that occurred in the Analysis of 13 Principles file using the 6,333 btu/kWh heat rate. Please see the above attached (see file with "_IH" in filename). There may be corresponding numbers that may need to be adjusted in the Need and Fiscal Form as a result of the above attached numerical adjustments recommended.

Please advise if there are any questions. Thank you for the opportunity to review and provide comments on the above.

Respectfully,
Irene Heng
PacifiCorp | 825 NE Multnomah St. 1500, Portland, OR 97232-2135 | (503) 813-5589

From: SIERMAN Jason * ODOE [mailto:Jason.Sierman@oregon.gov]
Sent: Wednesday, May 02, 2018 3:58 PM
To: 'Amelia Reiver Schlusser' <ars@lclark.edu>; powers@lclark.edu; Tyler C. Pepple <tcp@dvclaw.com>; jcarr@icnu.org; fred@nwenergy.org; wendy@nwenergy.org; 'Dan Serres' <dan@columbiariverkeeper.org>; 'Mia Reback' <mia@350pdx.org>; LAWRENCE Rhett <rhett.lawrence@sierraclub.org>; 'robert.brunoe@ctwsbnr.org'; 'Matthew Johnson' <MatthewJohnson@ctuir.org>; 'Cavanaugh, Darren' <Darren.Cavanaugh@avangrid.com>; 'Lynch, Kevin' <Kevin.Lynch@avangrid.com>; sreynolds@calpine.com; 'rkahn@nippc.org'; 'Bauer, Gary' <Gary.Bauer@nwnatural.com>; 'Bauer, Andrew P.' <Andrew.Bauer@nwnatural.com>; 'Shanna Brownstein' <shanna.brownstein@nwnatural.com>; 'Brendan McCarthy' <brendan.mccarthy@pgn.com>; Heng, Irene <Irene.Heng@pacificorp.com>; Wiencke, Mary <Mary.Wiencke@pacificorp.com>; Teply, Chad <Chad.Teply@pacificorp.com>; Bice, Jordan <Jordan.Bice@pacificorp.com>; Doris Penwell <dpenwell@oregoncounties.org>; 'Michael Eliason' <meliason@oregoncounties.org>; 'Angus Duncan' <aduncan@b-e-f.org>; AlanZelenka@ZelenkaEnergyandClimate.com; 'Alan Zelenka' <AlanZelenka@KennedyJenks.com>; MCCONNAHA Colin <Colin.McConnaha@state.or.us>; 'Mike Starrett' <MStarrett@NWCouncil.org>; BLEAKNEY Leann <lbleakney@nwcouncil.org>

PacifiCorp

Attachment 1

(to email dated 5/4/2018)

Oregon Department of Energy
Analysis of 13 Principles for
Amending the Carbon Dioxide (CO2) Standards

Overview

ORS 469.503(2)(a) and OAR 345-024-0570 give the Council the authority to reset the Council's carbon dioxide (CO2) emissions standard for base load gas plants. ORS 469.501(1)(o) and OAR 345-024-0610 give the Council the authority to reset the Council's CO2 emissions standards for non-base load power plants. ORS 469.503(2)(b) and OAR 345-024-0640 give the Council the authority to reset the Council's CO2 emissions standard for nongenerating energy facilities. OAR 345-024-0610 and -0640 require the CO2 standards for non-base load power plants and nongenerating energy facilities to be equivalent to the CO2 standard for base load gas plants.

OAR 345-024-0570 Modification of the Standards for Base Load Gas Plants

> *The Council may by rule modify the carbon dioxide emissions standard for base load gas plants in OAR 345-024-0550 if the Council finds that the most efficient stand alone combined cycle, combustion turbine, natural gas fired energy facility that is commercially demonstrated and operating in the United States has a net heat rate of less than 6,955 Btu per kilowatt hour higher heating value adjusted to ISO conditions. In modifying the carbon dioxide emission standard, the Council shall determine the rate of carbon dioxide emissions per kilowatt hour of net electric output of such energy facility, adjusted to ISO conditions and reset the carbon dioxide emissions standard at 17 percent below this rate.*

Under the above authority and in compliance with the above statutes and rules, the Department has identified what could be the most efficient combined cycle, combustion turbine (CCCT) natural gas-fired energy facility operating in the U.S. The Grand River Energy Center in Chouteau, Oklahoma has a tested higher heating value (HHV) net heat rate adjusted to ISO conditions of 6,333 Btu per kilowatt hour (kWh). (a summary of the test data is not available yet, but will be attached to the staff report to EFSC for the April, 27 EFSC meeting if it is received in time)

Since 6,333 Btu/kWh is less than the existing benchmark heat rate of 6,955 Btu/kWh (called out in OAR 345-024-0570, see above), the Department recommends the Council adopt 6,333 Btu/kWh as the new benchmark heat rate in OAR 345-024-0570 and use 6,333 Btu/kWh to reset the carbon dioxide (CO2) emissions standard for base load gas plants in OAR 345-025-0550. To reset the base load CO2 standard, 6,333 Btu/kWh must first be reduced by 17% to 5,256 Btu/kWh. Then 5,256 Btu/kWh must be multiplied by 0.000117 lbs. CO2/Btu to convert the heat rate into an emissions rate. This conversion yields an emissions rate of 0.615 lbs. CO2/kWh.

Therefore, in compliance with the above statutes and rules, the Department recommends the CO2 emissions standard for base load gas plants be reset to 0.615 lbs. CO2/kWh, and the standards for non-base load power plants and nongenerating energy facilities be reset to that equivalent. The standard for non-base load power plants would be reset to 0.615 lbs. CO2/kWh, and the standard for nongenerating energy facilities would be reset to 0.459 lbs. CO2/hp-hr [the horsepower hour (hp-hr) equivalent of 0.615 lbs. CO2/kWh]. The current rate for base load and non-base load pants is 0.675 lbs./kWh and the current rate for nongenerating facilities is 0.504 lbs. CO2/hp-hr.

13 Principles

OAR 345-024-0510 specifies 13 principles [also specified in ORS 469.503(2)(b)] that the Council must consider and balance in adopting or amending CO2 emissions standards for fossil-fueled power plants:

OAR 345-024-0510 Principles for the Adoption of New Standards for Fossil-Fueled Power Plants

> *The Council shall adopt carbon dioxide emissions standards for fossil-fueled power plants by rule. In adopting or amending such carbon dioxide emissions standards, the Council shall consider and balance at least the following principles. In the rule-making record, the Council shall include findings on these principles:*

(1) Promote facility fuel efficiency;

Pursuant to statute and rule, the proposed CO2 emissions standards are 17 percent lower than the emissions rate of the most efficient natural gas-fired CCCT operating in the U.S. Ensuring the standard is set modestly below the most efficient technology available and operating helps drive the development of more fuel efficient plants because the more efficient a plant is the less CO2 emissions that plant must offset to meet the standard. Fuel efficiency is the most direct and most certain way to reduce CO2 emissions.

(2) Promote efficiency in the resource mix;

Depending on load growth, fuel costs, and the retirement of aging power plants in Oregon, the proposed CO2 emissions standards may promote an increase in the percentage of high efficiency natural gas-fired power plants sited in Oregon relative to other conventional thermal power plants sited in Oregon. The proposed CO2 emissions standards are not predicted to promote an increase or decrease in the percentage of non-conventional energy facilities sited in Oregon. In 2000, natural gas was around 8 percent of the regional mix. As of January 2018, natural gas is around 14% of the regional mix.

(3) Reduce net carbon dioxide emissions;

Indirectly reducing the net CO2 emissions from fossil-fueled energy facilities sited in Oregon is the main function of the existing CO2 emissions standards. The proposed standards will continue to indirectly reduce the net CO2 emissions of future fossil-fueled energy facilities sited in Oregon by requiring those facilities to reduce their net greenhouse gas emissions to meet or beat the applicable CO2 standard. The proposed CO2 emissions standards may also directly reduce the gross CO2 emissions from future fossil-fueled energy facilities sited in Oregon by encouraging developers to build the most efficient energy facility possible. Facilities have three compliance pathways to reduce their net greenhouse gas emissions: 1) Monetary Pathway, where facilities pay The Climate Trust to procure greenhouse gas offset projects; 2) Self-Implementation Pathway, where facilities procure or implement their own greenhouse gas offset projects; and 3) Cogeneration Pathway, where new facilities are designed to displace greenhouse gas emissions that would have otherwise occurred but for the energy supplied by the new facility. To date, all site certificate holders have complied via the monetary pathway. Carbon dioxide is just one of many greenhouse gases that may be reduced through greenhouse gas offset projects.

(4) Promote cogeneration that reduces net carbon dioxide emissions;
The proposed CO2 emissions standards do not affect cogeneration as an option for an offset.

(5) Promote innovative technologies and creative approaches to mitigating, reducing or avoiding carbon dioxide emissions;
The proposed CO2 emissions standards do not affect the opportunity for a developer to comply via the Self-Implementation Pathway or the Cogeneration Pathway that already exist, where developers can propose to implement innovative technologies and creative approaches to mitigating, reducing or avoiding CO2 emissions, including offset projects that are more cost-effective than relying on the monetary path. Also, the Monetary Pathway does not limit the types of greenhouse gas offset projects a qualified organization (The Climate Trust) may procure.

(6) Minimize transaction costs;
The proposed CO2 emissions standards do not affect the Monetary Pathway that already exists, a pathway that presents an opportunity for a developer to minimize transaction costs by allowing compliance through a single transaction, i.e. providing the required offset funds to a qualified organization.

(7) Include an alternative process that separates decisions on the form and implementation of offsets from the final decision on granting a site certificate;
Continued use of the existing Monetary Pathway fulfills this principle.

(8) Allow either the applicant or third parties to implement offsets;
The proposed CO2 emissions standards do not affect the Self-Implementation Pathway that already exists.

(9) Be attainable and economically achievable for various types of power plants;

Table 1

Table 1 compares the excess emissions (in short tons) of the two most efficient facilities the existing and proposed standards are based upon if those facilities were built in Oregon with a nominal generating capacity of 370 MW. The left column shows the excess emissions of the River Road Generating Plant in Vancouver, WA (the facility upon which the existing standard is based), if that facility were constructed in Oregon under the existing standard. The right column shows the excess emissions of the Grand River Energy Center in Chouteau, OK (the facility upon which the proposed standard is based), if that facility were constructed in Oregon under the proposed standard.

By design, and contrary to intuition, resetting the CO2 standards to a lower net emissions rate based upon the most efficient technology currently in operation (effectively decreasing the threshold limit for a facility's net CO2 emissions) actually has the net effect of decreasing, not increasing, the excess quantity of CO2 emissions a highly efficient power plant would need to account for in order to comply with the CO2 standards. This decrease is shown in Table 1.

The decrease in the excess quantity of CO2 emissions that a highly efficient power plant must account for under a lower CO2 standard arises from the fact that as plants become more efficient, the 17 percent reduction of the emissions rate of the most efficient power plant operating in the U.S. (i.e. how the standard is reset) becomes a smaller and smaller absolute reduction.

Assumptions:

The assumption of 370 MW is for illustrative purposes only. The assumption of annual operating hours of 8,760 (a 100% capacity factor) and 30 years of operation are specified in rule.

Table 1 **Under the Proposed Standard -** **Excess Emissions Decrease for Plants Sited in Oregon With the Most Efficient Technology**		**Then** **(Yr. 2000)** **River Road** **Existing Standard**	**Now** **(Yr. 2018)** **Grand River** **Proposed Standard**
A	Heat Rate - Most Efficient Technology (Btu/kWh)	6,955	6,333
B	CO2 Emissions Rate (lbs. CO2/Btu of Natural Gas)	0.000117	0.000117
C (=A*B)	Gross CO2 Emissions Rate (lbs. CO2/kWh)	0.8137	0.7410
D	**EFSC Standard - Net CO2 Emissions Rate** (lbs. CO2/kWh)	**0.675**	**0.615**
E (=C-D)	Excess CO2 Emissions Rate (lb. CO2/kWh)	0.1387	0.1260
F	Lifetime Plant Output (million kWh) **370 MW Plant * 8,760 hours * 30 years**	97,236	97,236
G (=F*C)	Lifetime Gross CO2 Emissions (million lbs.)	79,121	72,052
H (=G/2000)	Lifetime Gross CO2 Emissions (million short tons)	39.56	36.03
I (=F*E)	Lifetime Excess CO2 Emissions (million lbs.)	13,487	12,252
J (=I/2000)	**Lifetime Excess CO2 Emissions** (million short tons)	**6.74**	**6.13**
K	**Net Decrease Between Standards** (million short tons)		**(0.61)**

Table 2

Table 2 shows the excess emissions (in short tons) of two facilities under the proposed standard. The left column shows the estimated excess emissions of a hypothetical, less efficient, natural gas-fired power plant sited in Oregon under the existing standard. The right column shows the estimated excess emissions of the same hypothetical, less efficient, plant if it were sited under the proposed standard rather than the existing standard.

Assumptions:
The assumptions of a nominal capacity of 370 MW and a design heat rate of 6,688 Btu/kWh are for illustrative purposes only. The assumption of annual operating hours of 8,760 (a 100% capacity factor) and 30 years of operation are specified in rule.

Table 2 **Under the Proposed Standard -** **Excess Emissions Increase for Plants Sited in Oregon With Less Efficient Technology**		**Then** **(Yr. 2013)** **Less Efficient Plant Under Existing Standard**	**Now** **(Yr. 2018)** **Less Efficient Plant Under Proposed Standard**
A	Heat Rate (Btu/kWh)	6,688	6,688
B	CO_2 Emissions Rate (lbs. CO_2/Btu of Natural Gas)	0.000117	0.000117
C (=A*B)	Gross CO_2 Emissions Rate (lbs. CO_2/kWh)	0.782	0.782
D	**EFSC Standard - Net CO_2 Emissions Rate** (lbs. CO_2/kWh)	**0.675**	**0.615**
E (=C-D)	Excess CO_2 Emissions Rate (lbs. CO_2/kWh)	0.107	0.167
F	Lifetime Plant Output (million kWh) **370 MW Plant @ 8,760 hours @ 30 years**	97,236	97,236
G (=F*C)	Lifetime Gross CO_2 Emissions (million lbs.)	76,039	76,039
H (=G/2000)	Lifetime Gross CO_2 Emissions (million short tons)	38.02	38.02
I (=F*E)	Lifetime Excess CO_2 Emissions (million lbs.)	10,404	16,238
J (=I/2000)	**Lifetime Excess CO_2 Emissions** (million short tons)	**5.20**	**8.12**
K	**Net Increase Between Standards** (million short tons)		**+ 2.92**

Table 3

Table 3 shows an estimate of the cost of compliance for two facilities under the proposed standard. The column on the left shows the cost of compliance for the Grand River Energy Center (the highly efficient plant the proposed standards are based upon) if that plant were to be sited in Oregon with a nominal generating capacity of 370 MW under the proposed standard. The column on the right shows the cost of compliance for a hypothetical, less efficient, 370 MW natural gas-fired plant sited in Oregon under the proposed standard.

Assumptions:
As in Tables 1 and 2, the assumption of a nominal capacity of 370 MW and a design heat rate of 6,688 Btu/kWh are for illustrative purposes only. The assumption of annual operating hours of 8,760 (a 100% capacity factor) and 30 years of operation are specified in rule.

Table 3 **EFSC Compliance Costs Under Proposed Standards**		**Grand River Energy Center**	**Less Efficient Power Plant**
A	Excess Tons CO2 (million tons over 30 years)	6.13 (see Table 1)	8.12 (see Table 2)
B	Offset Fund Rate ($/ton CO2)	$ 1.90	$ 1.90
C (=A*B)	Offset Funds Required ($ million)	$ 11.647	$ 15.428
D	Contracting and Selection Funds (10% of first $500k, 4.286% of remainder) ($ million)	$ 0.53	$ 0.64
E	**Total Monetary Path Requirement ($ million)**	**$ 12.17**	**$ 16.12**

Table 4

Table 4 shows an estimate of the siting, construction and operating costs of a representative 370 MW gas-fired CCCT power plant over 30 years. The left column shows the plant operating 7,884 hours per year (90% capacity factor). The right column shows the plant operating 5,256 hours per year (60% capacity factor). The cost data is from the 7th Power Plan from the Northwest Power and Conservation Council (NWPCC) and has been converted from $2012 to $2018 for illustrative purposes.

Assumptions:

The assumption of a nominal capacity of 370 MW is for illustrative purposes only. The assumption of a 90% annual operating capacity factor for base load operation (EFSC rules classify plants operating more than 75% of total operating capacity as base load) is used to reflect a typical plant's availability inclusive of maintenance and unplanned outages. The assumption of a 60% annual operating capacity factor for the plant under non-base load operation (EFSC rules classify plants operating less than 75% of total operating capacity as non-base load) is for illustrative purposes only. The assumption of a 30 year operating life is specified in rule.

Table 4 **NWPCC Construction and Operating Costs**		**Base Load Operation**	**Non-Base Load Operation**
A	Nominal Capacity (MW)	370	370
B	Life of Plant (Years)	30	30
C	Operating Capacity Factor	90%	60%
D	Annual Hours of Operation (Hours/Year)	7,884	5,256
E	Levelized Cost of Electricity (LCOE)* in 2018 dollars ($/MWh) *Includes capital, fixed and variable O&M, fixed and variable fuel using a median fuel price forecast, and BPA P2P Transmission.	$65.75 @ 90%	$78.43 @ 60%
F (=A*D*E)	Annual Cost* in 2018 dollars ($M/Year)	$191.8	$152.5
G (=PV of F)	**Lifetime Present Value Costs** in 2018 dollars ($B, Billions of Dollars) PV @ 4% discount rate for 30 years	**$3.317**	**$2.637**
H	Cost of Construction (2018 $M/MW)	$1.262	$1.262
I (=H*A)	**Construction Cost** in 2018 dollars ($M, Millions of Dollars)	**$466.9**	**$466.9**

Table 5

Table 5 shows the likely costs of compliance with the proposed CO2 standards via the Monetary Pathway for the facilities identified in Table 4.

NOTE: *Unlike the assumption of a 90% annual operating capacity factor for the base load operation used in Table 4 for estimating construction and operating costs, compliance costs are calculated using an annual operating capacity factor of 100% because EFSC statutes and rules specify a 100% capacity factor for base load operation.*

Table 5 **EFSC Compliance Costs for Most Efficient Technology**	**Base Load Operation**	**Non-Base Load Operation**
Capacity Factor Used for Compliance	100%	60%
Lifetime Excess CO2 Emissions (million short tons)	6.13 (See Table 1)	3.68
Total Monetary Path Requirement ($M)	**12.17** **(See Table 3)**	**7.32**

Table 6

Table 6 shows the likely compliance cost via the Monetary Pathway as a percentage of the present value of life-cycle plant costs and as a percentage of construction cost for the two power plant classifications in EFSC rules, base load and non-base load. The estimates of plant construction and operating costs are from Table 4 and the estimates of compliance costs are from Tables 3 and 5. The compliance cost for the less efficient non-base load plant is calculated for this table only, and is not present in any other tables in this document.

Table 6 **Economic Feasibility of Proposed Standard in 2018 dollars**	**Base Load (370 @ 90%)** Less Efficient Plant	**Base Load (370 @ 90%)** Most Efficient Plant	**Non-Base Load (370 @ 60%)** Less Efficient Plant	**Non-Base Load (370 @ 60%)** Most Efficient Plant
Monetary Path as % of **Lifetime Present Value Costs** (including fuel)	16.12M / 3.32B **0.49%**	12.17M / 3.32B **0.37%**	9.68M / 2.64B **0.37%**	7.32M / 2.64B **0.28%**
Monetary Path as % of **Construction Cost**	1[illegible]M / 466.9M **3.45%**	12[illegible]M / 466.9M **2.61%**	9.[illegible] / 466.9M **2.07%**	[illegible]2M / 466.9M **1.57%**

In the range of cases studied, the costs for a power plant to comply with the proposed CO2 standards are less than 0.5 percent of the total costs to site, construct, and operate a 370 MW CCCT plant for 30 years. The Department estimates the cost impact of the proposed standard would not be so large as to force the development of EFSC jurisdictional fossil-fueled energy facilities outside of Oregon. The Department recommends that the Council conclude that the proposed standard therefore is attainable and economically achievable.

(10) Promote public participation in the selection and review of offsets;
The proposed CO_2 emissions standards do not affect public participation in the review of offset projects a developer proposes to the Council.

(11) Promote prompt implementation of offset projects;
The proposed CO_2 emissions standards do not affect the certificate holder's responsibility to begin offset projects or to make offset funds available to the qualified organization prior to beginning construction; nor does it affect the requirements on the qualified organization to contract for projects within a specified time.

(12) Provide for monitoring and evaluation of the performance of offsets;
The proposed CO_2 emissions standards do not affect monitoring and evaluation of the performance of offsets.

(13) Promote reliability of the regional electric system.
The proposed CO_2 emissions standards are not likely to affect regional reliability of the electric system. The proposed standards are economically achievable, as discussed in principle (9) above. Therefore, if the reliability of the regional system required a plant to be developed in Oregon, the proposed standards would not prevent that. However, the Department knows of no electric reliability problem that can be resolved only by building a power plant in Oregon rather than another Northwest state.

Recommendation
The Department recommends that the Council find that most efficient CCCT natural gas-fired power plant operating in the U.S. is the Grand River Energy Center in Oklahoma. Based on this finding, and after the Council considers and balances the 13 principles under 345-024-0510 and makes findings on these 13 principles, the Department also recommends that the Council adopt the proposed changes to OAR 345-024-0550, 345-024-0570, 345-024-0590 and 345-024-0620 that modify and reset the CO_2 standards. These proposed changes include:

345-024-0570 - Replacing 6,955 Btu/kWh with 6,333 Btu/kWh;

345-024-0550 - Replacing 0.675 lbs. CO_2/kWh with 0.615 lbs. CO_2/kWh

345-024-0590 - Replacing 0.675 lbs. CO_2/kWh with 0.615 lbs. CO_2/kWh

345-024-0620 - Replacing 0.504 lbs. CO_2/hp-hr with 0.459 lbs. CO_2/kWh.

Columbia Riverkeeper

Email Dated 5/4/2018

SIERMAN Jason * ODOE

From:	Dan Serres <dan@columbiariverkeeper.org>
Sent:	Friday, May 4, 2018 3:08 PM
To:	SIERMAN Jason * ODOE; LAWRENCE Rhett
Subject:	Feedback on CO2 standard
Attachments:	160918-19-Staff-Comments-re-PSE-2017-IRP.docx

Hi Jason -

Thank you for the opportunity to weigh in. I've had a chance to talk to Rhett Lawrence with Sierra Club about this, as well, so I've cc'd him here. The following are some of the main ideas we came up with regarding the proposed new heat rate. We generally support your staff analysis.

1. We don't have any information to disagree with the use of the Grand River Energy Center in Oklahoma as the most efficient plant. This is the most important part of the analysis, and you and the other EFSC staff appeared to do a thorough job.

2. We could encourage you to continue to look at the two plants in Florida more thoroughly, if possible (they were slightly better than the Oklahoma plant but they didn't have verified test data to share). If EFSC can find a more efficient heat rate, that will improve the standard, which will continue to underprice carbon pollution under the proposed changes. Right now, the change proposes an 8.9% improvement in the overall efficiency rate based on the Oklahoma plant (dropping benchmark heat rate from 6955 to 6333 Btu/kWh).

3. In general, the standard will continue to dramatically underprice carbon pollution. One useful comparison is the Social Cost of Carbon. Below we provide some examples of how other states addressed carbon costs. Most interestingly, the Washington UTC (at least in concept) acknowledged that the Social Cost of Carbon is a relevant consideration.

In February, the Washington UTC staff recommendation for Puget Sound Energy's Integrated Resource Plan stated:

- "Although PSE met the letter of the law by modeling various carbon prices in the IRP, the justification for ignoring the societal cost of carbon has no basis in rule. The societal cost of carbon is nationally recognized and widely used approach to quantify the very risks identified in the IRP rule. Until a better measure of the damages associated with greenhouse gas emissions is identified, it should be used in a default sensitivity or even the default scenario. Consequently, Staff recommends that PSE use estimated societal costs of carbon during the 2019 IRP analysis." (See attached)

In March, the Colorado Public Utilities Commission:

- Ordered Xcel Energy to use the federal SCC to measure harms from CO2 emissions in its 2016 Energy Resource Plan which will guide utility investments through 2024.
- http://coseia.org/wp2016/wp-content/uploads/2017/05/ERP-Decision-C17-0316_16A-0396E-1.pdf

In January, the Minnesota Public Utilities Commission:

- Issued an order finalizing carbon cost estimates that utilities must use when planning infrastructure projects setting them at a range of $9.05 to $42.46 per ton.

- https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={5066BD60-0000-C71B-9B5B-305CF65BCAE1}&documentTitle=20181-138585-01

By any measure, the Social Cost of Carbon exceeds the costs that would be involved with the revised carbon dioxide standard under the staff's recommendation because the offset fund rate is only $1.90/ton, and can't be raised again until 2019 without legislation. This information shows that the staff's analysis of the 13 factors is conservative and does not unfairly burden developers. In fact, the standard will continue to underprice carbon pollution. Improving the benchmark heat rate only barely begins to address this problem.

The standard also continues to ignore the lifecycle pollution of fracked gas production and transport. This sidesteps one of the biggest components of greenhouse gas pollution for fracked gas infrastructure - methane pollution during drilling and transport. This is probably not something that can be addressed in this rulemaking, but it shows that new gas-fired plants will continue to pay far less than the cost of the real impact of the carbon pollution they generate.

On balance, Oregon's standard will remain a bargain for greenhouse gas polluters.

Specific comments to 13 Factors:
1. Promote fuel efficiency - Agree with staff. If it were possible to confirm a more efficient heat rate in Florida or elsewhere, the standard would accomplish this goal more effectively.
2. Promote efficiency in the resource mix - Same as above.
3. Reduce net carbon dioxide emissions - Same.
4. Promote cogeneration - no comment
5. Promote innovative technologies - Agree with staff. If it were possible to confirm a more efficient heat rate in Florida or elsewhere, the standard would accomplish this goal more effectively.
6. Minimize transaction costs - no comment
7. Include an alternative process... - no comment
8. Allow either applicant or third parties to implement - no comment
9. Be attainable and economically achievable - Agree with staff analysis. We might also add that the Social Cost of Carbon is being incorporated into utility decisions in other states. By this measure, new gas-fired plants in Oregon will still be addressing only a small portion of the impact of their pollution through payments and offsets generated by EFSC's revised CO2 standard. The staff analysis shows that the cost will be reasonable. In fact, the costs are far too low.
10. Promote public participation in selection of offsets - no comment
11. Promote prompt implementation - no comment
12. Provide for monitoring and evaluation - no comment
13. Promote reliability of the regional electric system - Agree with staff.

Thank you, and have a good weekend,

Dan

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Dan Serres | Conservation Director
Columbia Riverkeeper | 1125 SE Madison Suite 103A Portland 97214
503.890.2441 | dan@columbiariverkeeper.org

Columbia Riverkeeper

Attachment 1

(to email dated 5/4/2018)

Appendix 1

Staff Detailed Comments on PSE's Final 2017 IRP

Appendix 1 - PSE Final 2017 IRP Staff Detailed Comments

Chapter, Page #, Action	Comment — Actions: S – Supplement to 2017 IRP; R – Request for 2019; G - General Comment
Ch. 1	
1-7 **R**	**Prudence of distributed resources.** In the electric action plan, item 2, PSE highlights the fact that the current established process for determining prudence of demand response resources does not fit well with the established process for large power plants. Whereas utility-scale power plants are typified by a large discrete capital spend with a clearly defined in-service date, acquiring demand response is more like acquiring energy conservation through relatively small expenditures spread across the service territory. Demand response programs acquire small increments of capacity and over time can cumulatively become a significant resource that displaces the need for future generating and distribution resources. Staff agrees with this perspective and would expand this to include not only demand response but other types of distributed energy resources which include capacity. Prudence determinations go well outside of the IRP context by considering decisions and actions of utilities after the IRP is completed. Therefore, while prudence is a relevant topic, it cannot be fully explored in the forward looking IRP process because prudence determination is made retrospectively.
1-8 **G**	**RFP requirements for capacity do not exempt conservation or demand response resources.** Electric action item 4 calls for a 2018 "all sources" Request For Proposal (RFP) which could solicit conservation, DR, and other, more traditional, resource opportunities. For the near term, PSE's IRP cites conservation and demand response resources to fill PSE's capacity deficits. As required by WAC 480-107-015, an RFP must be submitted to the Commission within 135 days of the IRP due date if the utility has near-term capacity need within three years, including when conservation or demand response (DR) resources are used to fill the capacity need. PSE needs to submit an RFP or petition for an exception to the RFP rule if they have a capacity needs within three years, even if the most likely resources have been identified in the IRP.
1-11 **S**	**Tacoma LNG facility assumed to be an existing resource.** The natural gas sales action plan item 2 is to complete the Tacoma Liquefied Natural Gas (LNG) facility. PSE makes the assumption that the Tacoma LNG facility will be completed and in operation prior to the 2019/2020 winter season and may be needed to provide gas for peaking purposes as soon as the 2021/2022 winter season. However, even at this later stage in the project's development, the project has ongoing and potentially significant permitting issues.[1] Given that the plant is not completed or fully permitted, Staff believes the Company's assumption that a not-yet-operational resource will be available comes with some significant risk to the Company's gas supply. Consequently, Staff requests a supplement to this IRP in which the Company describes what it will do in the event that the LNG plant or pipeline upgrades are significantly delayed, or does not become operational at all.

[1] Puget Sound Clean Air Agency, "Current Projects: Puget Sound Energy - LNG Facility Tacoma." http://www.pscleanair.org/460/Current-Permitting-Projects

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1-22, and Figure 1-6 **S**	**WA public policy and carbon emissions.** PSE compares its forecast portfolio CO_2 emissions levels only with its emissions from 1990. As described in RCW 19.280.030(f), a utility must determine the lowest reasonable cost and risk mix of supply-side generating resources and conservation and efficiency resources, with <u>consideration of public policies regarding resource preference adopted by the state</u>. See RCW 19.280.020(11) Washington's public policy goal for greenhouse gases (GHG) is to reduce overall statewide emissions to 1990 levels by 2020. PSE's analysis is helpful in this regard as far as it provides a comparison to 1990 emission levels. However, at RCW 70.235.020(1)(a) there are additional Washington public policy looking further into the future to 2035 an 2050. These future public policy goals, are GHG emissions to 25 percent below 1990 levels by 2035, and to 50 percent below 1990 levels by 2050. Staff recognizes that PSE does not operate in an emissions vacuum. For instance, generating electricity for vehicle electrification is likely to have GHG transportation emission reductions that offset utility-scale electricity generation emissions. There are many complicating factors, some of which are outside of PSE's control in addition to factors that are within PSE's control or that PSE can influence. PSE could provide additional value to policy-makers if it discussed such complexities relative to state policy in the next IRP. To properly consider its actions relative to Washington public policy on GHGs, PSE should supplement the 2017 IRP to explain and illustrate how its forecast resource acquisition will contribute to meeting these state policy goals at least through 2035, which is within the 20-year planning timeframe. To the extent it may be able to project its contribution to these state goals in 2050, it would also be appropriate to forecast in the 2019 IRP.
Ch. 2	
2-3 **R**	**Clarify timing for base case resource additions.** Figure 2-1 and others in this chapter consistently represent resource additions at timeframe snapshots of 6, 10 and 20 years in the future under differing scenarios and sensitivities. However, the actual timing of resource additions vary by individual year in the models. For instance, on page 2-3 it is recognized that new thermal peaking resources will likely not be needed until the year 2025. It would be useful to provide additional insight by showing the year of each additional resource type needed, at least for the base scenario in Chapter 2. At a minimum, PSE should reference the specific appendix and page number with additional detail in Chapter 2.
2-8 **R**	**Diligence in tracking renewable energy costs.** This IRP focused on utility-scale solar and wind resources to satisfy future renewable portfolio standard (RPS) obligations. PSE was surprised that solar appears to be slightly more cost-effective than wind resources. This surprise reflects the rapidly changing pricing of solar and wind resources. Because costs of solar photovoltaics, onshore wind and offshore wind resources have been declining at different rates, PSE should continue to track and carefully project cost trends for all three of these renewable resources and for any other promising utility-scale eligible renewable resources for use in the next IRP. As an example of the changing marketplace, Europe continues to lead the way in offshore wind development and demonstration of cost reductions. In 2016, the United Kingdom had 15 GW of

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	installed wind energy capacity and 35 percent of that capacity was located in offshore wind farms.[2] European offshore wind costs have been declining rapidly and until recently most bids for offshore wind energy included government subsidies. Three recent utility-scale offshore wind energy bids in the Netherlands and Germany were offered at under 0.06€/kWh levelized cost of energy in 2016 without subsidies, or approximately $0.07/kWh US. This is in the same magnitude of costs shown in Figure 2-5, page 2-10 for northwest utility-scale renewables. This European pricing has not yet been demonstrated in the US market, but might occur within the time horizon of RPS need for PSE. Significant cost reductions are widely anticipated for all wind resources, while solar cost reduction projections are less certain. PSE does not project needing additional RPS resources to meet its obligations until approximately 2023. By then, US offshore wind bids might become competitive with northwest onshore wind and solar based on a declining levelized cost of energy and its contribution to peak capacity. According to Figure 6-4, Washington offshore wind contribution to peak capacity is approximately 51 percent, higher than any other wind or solar resource examined in the IRP. This increases the energy value of offshore wind compared to other intermittent renewable resources. PSE needs to more diligently track and project future renewables costs and benefits in the 2019 IRP.
2-9 **G**	**Resource study cost recovery does not rely on acquiring the studied resources**. PSE indicates hesitation in paying for studies to examine the viability of a potential resource because "we may not be allowed to recover the cost of the study if it did not directly lead to a resource acquisition." Staff is unaware of any study undertaken by a utility where the expenditures for studying potential solutions were partially or fully disallowed by this Commission. To the contrary, even anecdotal information about emerging resources creates an obligation to perform a reasonable level of investigation during the planning process. Otherwise, the most cost-effective solutions may be inadvertently overlooked during the planning process, possibly leading to the acquisition of more expensive resources than required to fill the recognized need. It is well understood that studying the potential benefits and costs of any single or combinations of resources does not commit the utility to acquire any of those potential solution sets. In fact, the whole IRP process is a study where there is no intent to box the Company into acquiring any, let alone all, of the resources studied. This is clearly stated at page 1-6 of the IRP, "Specific energy efficiency and supply-side resource decisions are not made in the context of the IRP." Furthermore, inadequate study that mischaracterizes the cost of a promising resource may lead the Company to go down the path of acquiring the wrong resources, ones that are not least-cost and least-risk, or ones that might not provide other desirable characteristics such as faster ramping rates or increased flexibility. PSE's statement that study costs may be disallowed "if it did not directly lead to a resource acquisition" is simply incorrect and should not appear in future IRPs. In order to fulfill the regulatory IRP requirements of gas and electric planning, the Company must use modeling tools to identify the lowest reasonable cost resources "through a detailed and consistent analysis of a wide range of commercially available resources"[3]. This can only be

[2] Renewable Energy Foundation, "Grouped totals for Renewable Generation: 2002 to date." http://www.ref.org.uk/generators/group/index.php?group=yr
[3] Excerpted from definition of "Lowest reasonable cost" from WAC 480-90-238(2)(b) and WAC 480-100-238(2)(b).

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	accomplished by studying many potential resource options that are commercially available to the utility and its customers. While not every possible option can be studied in great detail, the blanket statement made by PSE that study costs may not be recoverable appears to be based on no evidence, and could lead PSE to ill-informed and potentially imprudent decision-making. PSE should examine all potential resources at an appropriate level, and continue to screen candidate resources with potential short-term as well as long-term promise for more detailed study. Staff recommends that PSE avoid using the supposed risk of disallowed cost recovery as a rationale for not exploring a broad range of traditional and emerging potential resources unless it can show that such a disallowance has occurred in this state.
2-19 **G**	**Choosing demand response and storage even though the Base Scenario doesn't reflect all carbon risk.** PSE compares Scenarios 9 and 14 with the Base Scenario in deciding that it is worth the increased cost to include demand response and energy storage. PSE's modeling results in the Base Scenario project that such a portfolio may be 0.1 percent, or $9 million more expensive than the least-cost portfolio over 20 years. PSE states that "[t]his is an insignificant cost to avoid building a fossil fuel plant that will have at least a 35-year life, to make sure it will be a good long-term investment on behalf of our customers." Staff appreciates the additional explanation about the process that guided the Company to its preferred portfolio.
Ch. 3	
3-3 **R**	**Provide transparency regarding PSE as party to CAR legal challenge.** The IRP mentions on page 3-3 that the Clean Air Rule "is the subject of several lawsuits challenging [its] validity." PSE neglects to mention that the Company is an active participant in the legal effort to invalidate the CAR. In the interest of transparency, PSE should reveal that they are a party to that action and explain why PSE chose to be a party and update the status of those cases in the 2019 IRP.
3-5 **S**	**Strategy to mitigate risk of regional resource inadequacy.** PSE notes on page 3-5 that its reliance on market purchases means it "must monitor regional resource adequacy issues closely and be prepared to modify our purchase strategy accordingly should changing conditions warrant." Staff applauds PSE for recognizing this risk and further honing its analysis of this risk in Appendix G. However, PSE does not explicitly describe a risk mitigation strategy. Staff recommends that PSE supplement this IRP, explicitly describing its market reliance risk mitigation strategy and its rationale, to the extent this can be made publicly available without revealing sensitive market information.

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3-7, 3-8 and 3-11 **R**	**Modeling for regional climate change impacts.** PSE indicates that the region is experiencing long-term warming according to recent University of Washington / National Oceanic and Atmospheric Administration climate scientist studies. PSE has begun to question using extreme cold weather values to represent peak winter days or hours in modeling gas and electric peak demand. Page 3-8 states that if normal "temperatures are changing, we need to plan for that change and account for it in our modeling." On the other hand, if the science indicates that weather extremes are more likely in the future and those extremes include higher winter peak energy demand, more resources may be needed. PSE identifies gaps in information that it needs to better plan for climate change, noting that, "Developing or getting access to regional forecasts that will give us the information outlined above is a priority for PSE." Staff recommends that PSE explore the costs and benefits of identifying or developing this data, and consider opportunities to collaborate with other utilities, or to share the expense of a consultant. This effort should evaluate whether the continued use of older weather data sets, with extreme cold hours and days, is still appropriate to use in modeling peak energy demand and to represent future weather and hydro conditions. PSE should include the specific actions it is taking in pursuit of this priority and any findings achieved to date in the next IRP.
3-12 **G**	**Sub-hourly modeling is encouraged.** PSE has started evaluating the value of selected resources that provide energy services on a sub-hourly and flexible basis, many of which include emerging technologies. Commission Staff welcomes these new analyses and encourages additional efforts to use these modeling tools to understand at a more granular level the various costs and benefits of emerging technologies. These modeling tools could help PSE capture the cumulative value of smaller distributed energy resources as well, which may provide significant system benefits to PSE's customers.
Ch 4	
4-13 **R**	**Characterize differences in gas price forecasts accurately.** On page 4-13, the Company states, "PSE's base Scenario gas price is slightly lower than the Council's medium gas price forecast." In Figure 4-10, PSE's base price is $4.02. The Council's medium price is $6.01, about 50 percent more than PSE's. The difference is significant enough to choose better words to describe the variance, and warrants an expanded narrative explaining how price forecasts can vary so widely. If PSE uses a similar divergent value for gas in the next IRP the difference should be addressed more clearly.
4-16 **R**	**Modeling estimated environmental costs and benefits is required.** PSE states that it did not choose to model a scenario or sensitivity using the societal costs of carbon emissions. The IRP states that "[t]he societal cost of carbon does not fit this regulatory model." In support of this, PSE states the IRP rule requires them to focus on "the costs and benefits that will be experienced by the utility and their customers." This regulatory interpretation is misleading and incomplete. The IRP rule for electric utilities, WAC 480-100-238, defines the costs and risks to be explored in developing an IRP in very broad terms, not the limited scope suggested by PSE's 2017 IRP. An IRP is defined to be a plan to meet current and future needs of the utility and its rate payers at the lowest reasonable cost, per WAC 480-100-238(2)(a). This specific component of the WAC definition is consistent with PSE's statement in the IRP. However, the next definition in the IRP

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R	rule provides an expansive view of what is meant by the term "lowest reasonable cost." "Lowest reasonable cost means the lowest cost mix of resources determined through a detailed and consistent analysis of a wide range of commercially available sources. <u>At a minimum, this analysis must consider</u> resource cost… and the <u>cost of risks associated with environmental effects including emissions of carbon dioxide</u>," WAC 480-100-238(2)(b). This rule requirement to include cost of risk of carbon dioxide emissions is contrary to PSE's assertion that the societal cost of carbon should not be considered in their IRP process. Although PSE met the letter of the law by modelling various carbon prices in the IRP, the justification for ignoring the societal cost of carbon has no basis in rule. The societal cost of carbon is nationally recognized and widely used approach to quantify the very risks identified in the IRP rule. Until a better measure of the damages associated with greenhouse gas emissions is identified, it should be used in a default sensitivity or even the default scenario. Consequently, Staff recommends that PSE use estimated societal costs of carbon during the 2019 IRP analysis. In addition, PSE chose not to model the monetized cost of the health impacts from fossil-fuel emissions that operate to serve customer loads. Incorporation of those costs were not performed in the 2017 IRP despite Staff bringing this issue to the attention of PSE in an e-mail on March 18, 2016, and at later advisory group meetings. Staff shared that this is required based on both the IRP rule as well as excerpts of a letter from the Commission to the NW Power and Conservation Council in December 2015 on the same issue. Although the focus of the Commission letter was on the health impacts of small particulate emissions, referred to as PM 2.5, emissions of oxides of sulfur and nitrogen have also been monetized by US EPA using actual quantified and monetized health impacts. Where electric generation emission impacts have been monetized, those costs should be included in the 2019 IRP resource cost modeling. Staff recommends that PSE perform the analysis to include the health impact costs of emissions from its fossil-fuel resources serving customer electric load in its 2019 IRP. Various tools have been developed by US EPA to facilitate the application of these monetized health benefits of reduced emissions from utility-scale generators.
4-18 **R**	**Use contemporaneous pricing of RECs.** PSE shows in Figure 4-12 its estimate of the "High CAR – fundamental PSE REC price." This price is a flat line on the graph reflecting the relatively high 2015 IRP wind energy levelized costs of $110. As mentioned previously in these comments, the cost of utility-scale wind resources is rapidly changing and anticipated to continue to decline. Staff recommends that PSE to update the levelized-cost-fundamental price of RECs in Figure 4-12 to reflect contemporaneous wind costs and as inputs to the cost modeling in the 2019 IRP.
4-29 **R**	**Correct offshore wind potential characterization and cost assumptions.** PSE has been exploring offshore wind potential, and paid a consultant to do some preliminary examination of the offshore wind resources on the Washington coast. However, there were some questionable assumptions made in the analyses. For background, as ocean water depths increase beyond approximately 60 meters, the feasible offshore wind installations transition from fixed-bottom (attached to the seafloor) to floating platforms, which are more expensive and less proven. Page 4-29 of the IRP states that wind facilities "off the coast would have to be located in deep water more than 22 miles offshore since

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	established shipping lanes run the entire length of the Washington coast." At more than 22 miles from the Washington coast the seafloor is much deeper than 60 meters which would require the more expensive floating platforms as well as longer, costlier transmission lines to deliver the power to the on-shore transmission grid. Attachment A shows shipping paths of cargo ships in 2013 off the southern Washington coast from National Oceanic and Atmospheric Administration vessel tracking data. From a simple examination of actual shipping patterns in 2013 the need to be more than 22 miles from the shore to avoid shipping lanes appears to be a false statement. The yellow line along the coast depicts the 60 meter water depth, which is less than 20 miles from shore. The preponderance of dark blue cargo ship traces is beyond 20 miles from shore, the opposite of the statement made on page 4-29 in the IRP quoted above. This does not include commercial fishing vessels which are less regimented in their travels but whose paths are mostly concentrated between 5 and 50 miles from shore, again based on 2013 vessel tracking data (not shown here). A likely rationale for PSE's consultant assumption, that offshore wind farms must be more than 22 miles offshore, is because that is approximately how far from shore wind turbines would visually fall below the horizon as the earth's surface curves. This is a strategy used by some wind developers, but is not a technical nor regulatory requirement. For planning purposes there appears to be no justification for such a costly restriction. Consequently, Commission Staff recommends that PSE consider the potential placement of offshore wind farms inside the 60 meter offshore water depth line as an alternative to deep water locations to reduce the cost estimates for Washington offshore wind resources in the next IRP. In addition, PSE should use projected cost reductions for offshore wind, as it does for other resources, to make a fair cost comparison between various future eligible renewable resources.
Ch. 5	
5-7 **R**	**Broaden the variety of distributed resources evaluated.** PSE should examine a "wide range of conventional and commercially available nonconventional generating technologies" as called for in the IRP rule at WAC 480-100-238(3)(c) including all forms of distributed generation. In addition, other distributed resources such as electric vehicles, energy storage, and a modernized distribution grid need to be carefully assessed to be consistent with the IRP rule which requires a "comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation" at WAC 480-100-238(3)(e). For demand-side conservation that is reliable, available and cost-effective, PSE subtracts those resources contributions from the system load and peak forecasts. In similar fashion, other reliable, available cost-effective demand-side distributed energy resources should be accounted for the same way in the IPR process as well as internal financial planning. For IRP purposes stacked benefits in addition to energy and capacity must be modeled to reflect the true value of distributed resources. Fortunately PSE has started down this path already by exploring the resource value of flow batteries, advanced metering infrastructure implementation, demand response programs, and, in a few cases, evaluating alternatives to traditional distribution circuit upgrades. This effort should be expanded to be more inclusive by modeling additional types of distributed energy resources as

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	mentioned in the prior paragraph, as well as compiling circuit-specific evaluations where distribution system changes or additions are anticipated or contemplated.
5-7 and 5-8 **R**	**Model electric demand forecasts with retrofit conservation in years 11 through 20.** Demand forecasts set the baseline expectations for the size and type of future resources needed to serve customer loads. In the past few IRPs the expectations looking 20 years ahead have consistently been optimistic in projecting larger and faster growth than realized. This was highlighted in a study by the Lawrence Berkeley National Laboratory (LBNL) of utility average annual growth rate of energy (AAGR). LBNL results for PSE are shown below[4].

Period	PSE Projected AAGR	PSE Actual AAGR
2006-2014	1.75%	-0.19%
2012-2014	1.90%	-1.19%

The historic mismatch between projected and actual growth has resulted in a trend of lower energy growth predictions in PSE's IRP as shown in this table.

PSE IRP Vintage (citation)	Annual Average 20-year Electric **Energy** Growth	Annual Average 20-year Electric **Peak** Growth
2009 (Chapter 4)	1.95	1.7
2011 (Appendix H)	2.0	1.6
2013 (Appendix H)	2.0	1.9
2015 (2017 IRP, p. 5-2)	1.7	1.6
2017 (p. 5-2)	1.4	1.3

Aggressive energy conservation programs are a significant factor in declining demand forecasts. Staff suggests a revised approach to modeling the effect of conservation in IRPs to further improve the projected demand growth rates shown in the 2017 IRP.

Page 5-8 of the 2017 IRP projects yearly growth rates which consist of a blend of flat to negative growth in the first 10 years when there is projected aggressive energy conservation. PSE's aggressive conservation program fills most of the expected energy growth needs in the first 10 years. PSE models the first 10 years of conservation by applying 20 years of retrofit conservation measures from the conservation potential assessment (CPA, Appendix J, pages 16 and 45) into the first 10 years of the IRP. This and prior IRPs have shown the advantages of this compressed conservation schedule as it provides both a more cost-effective conservation portfolio and a reduction in PSE's revenue requirement. The acceleration of conservation is not unreasonable because the CPA relies on average regional conservation uptake rates that are normally exceeded by PSE's conservation performance. Furthermore, PSE has a history of aggressive conservation and the ability to achieve its targets has been demonstrated in every biennial conservation target to date.

[4] Laurence Berkeley National Lab, "Load Forecasting in Electric Utility Integrated Resource Planning," October 2016, p. 25. https://emp.lbl.gov/publications/load-forecasting-electric-utility

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	However, the only conservation remaining in PSE's IRP model in years 11 through 20 are measures that are replaced on burn-out or new construction with zero contributions from retrofit conservation measures. This lack of any retrofit conservation in the later years significantly affects the energy demand and therefore the projected need for new resources beyond year 10. Staff believes that PSE should assume in years 11 through 20 that a reasonable level of emerging retrofit conservation measures will become available in the market at cost-effective rates even though they cannot be accurately identified or predicted now. It is not reasonable to model a complete lack of retrofit conservation measures and a drop to zero retrofit conservation measures beginning in year 11. This assumption will temper the model prediction of resource need in the out years to reflect a more rational expected energy demand future. It is recommended that PSE take this approach in their 2019 IRP.
5-18 **R**	**Model natural gas demand forecast with retrofit conservation in years 11 through 20.** Similar to the acceleration of electric conservation programs by assuming that all retrofit measures are installed in the first 10 years and no retrofits are assumed for years 11 through 20, gas conservation measures are modeled the same way in PSE's IRP. Therefore, Staff recommends that PSE make a reasonable assumption of some level of continued availability of retrofit natural gas conservation measures in the second half of the planning timeframe to refine the natural gas demand forecasts in the 2019 IRP.
5-31 **G**	**Focus on integrated planning for local high-growth areas.** Economic activity is a primary driver of energy growth and results in uneven needs across PSE's service territory. On page 5-31 PSE recognizes that King County is where the highest growth rates have occurred in PSE's service area due to economic activity and this trend is likely to continue. Localized future growth needs combined with increasing visibility and control of the grid distribution network provide opportunities to effectively plan and manage both energy loads and PSE infrastructure growth at a more granular level.[5] PSE should start evaluating the potential to roll up local distribution planning with a modernized grid into the larger-scale IRP process. King County and other areas with high projected energy growth would be candidate distribution circuits to examine first. This focus might be practically implemented in even years of the IRP cycle so that the results can be rolled into the IRP planning in the odd years. The evaluation of various combinations of distributed energy resource options applied routinely to these local areas should be a priority of the local planning efforts by PSE's distribution staff. This will require an increased integration of planning between PSE's staff from the IRP, transmission and distribution, conservation, and demand response groups. Staff recommends including this approach to evaluating circuits for grid modernization as soon as possible and continuing to the 2019 IRP work plan and future IPR cycles.

[5] Details regarding PSE's plans and potential benefits of distributed energy resources is summarized at pages 8-58 through 8-62.

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5-36 **R** **R**	**Fine-tune energy loss factors.** The 2017 IRP uses an electric loss factor of 7.3 percent. The loss factor is an approximation of the average system-wide energy losses between utility-generation and the end-use customers due to transmitting electricity over long distances, transforming its voltage, and flowing it through the distribution network. PSE is starting to install advanced metering infrastructure (AMI) and is continuing to modernize its distribution system with more efficient components which includes more granular monitoring and control. These upgrades allow for the prospect of closer control and balancing of voltages and reactive power and reducing the power required to serve the system and specific circuits. This ability to fine-tune the electrical system provides the clear potential to reduce electrical system losses over time. As the total load on a line increases the line losses increase faster, especially as the load nears the circuit design limits. Therefore, balancing loads between alternative lines and phases reduces overall losses. In the 2015 IRP the electric loss factor used was 6.9 percent. It is unclear why this value increased to 7.3 percent in the 2017 IRP. This wholesale increase in energy to cover increased losses affects the resource need projections and needs to be justified. Before the 2019 IRP is well under way, staff recommends that PSE begin a contemporaneous study of its system losses to set a new baseline that represents its electrical system. Staff recommends that the Company discuss details of the loss factor methodology and results with the IRP Advisory Group. Further, instead of estimating only a simple average annual electric system loss factor, Staff recommends that PSE estimate system seasonal and peak losses the can be used to fine-tune load forecasts in the 2019 IRP and use a seasonally variable loss factors in its IRP modeling. To complement the fine tuning of system losses, it would be useful for PSE to create a series of prototypical distribution circuits and calculate line losses that vary seasonally and during peak demand hours by type of prototypical distribution circuit before the end of 2019. Verification of these model circuits can be completed as the PSE grid is modernized. Implementing these recommendations will not only aid PSE in performing more accurate IRP distribution and transmission loss factor planning but also aid in transmission and distribution system planning for distributed energy resources that will roll up to the IRP system level planning.
5-37 **R**	**Model increasing loads from electric vehicles.** The increasing level of adoption of electric vehicles are likely to increase the aggregate demand profile at the distribution and system levels. For instance, as of June 2017 King County had 13,777 electric vehicles, 10,463 of which are battery electric vehicles (BEVs, battery power only, not plug-in hybrids)[6]. Added to this auto manufacturers are ramping up their offerings of electric vehicles and the average size of the batteries offered in BEVs is rapid increasing.[7] New BEV offerings now include larger battery packs in the 60+ kWh size which provide 200+ mile driving range. And based on EV sales history in WA, BEVs with larger battery sizes may be more dominant here than in other US

[6] Washington State Department of Transportation, "WA Plug-in Electric Vehicle Update through June 2017," September 8, 2017. http://www.westcoastgreenhighway.com/pdfs/PEVSummaryJune2017.pdf

[7] In 2011 there were only eight electric vehicle manufacturers selling in the US market each selling one electric vehicle model. In 2017 there were 42 models of electric vehicles sold into the US from 19 auto manufacturers. https://insideevs.com/monthly-plug-in-sales-scorecard/ General Motors has announced plans to introduce 20 new BEVs by 2023 and Ford plans to introduce 16 new BEVs by 2022.

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	locations. If these sales trends continue, WA utilities will have a larger than average potential energy demand from BEVs compared to other parts of the country. Assuming that electric vehicle adoption numbers continue to climb, Staff recommends that PSE include projections for the increased energy load from future electric vehicles in the 2019 IRP.
Ch. 6	
6-13 **R**	**Evaluate seasonal resources for peak capacity needs.** PSE's resource adequacy model simplifies the complexities of the grid by assuming resources are available all year and does not contemplate seasonal contracts to satisfy peak capacity needs. Seasonal energy contracts have been used in the northwest and are likely to be available in the future. Staff recommends that PSE model generic contracts for seasonal peak energy needs in the 2019 IRP to examine the impact of that energy market option.
6-62 through 6-66 **R**	**Update electric vehicle adoption rates.** As mentioned earlier, IRPs are supposed to consider state policies. Governor Inslee set a Results Washington goal of 50,000 electric vehicles in the state by 2020. In the year between June 2016 and June 2017, 6,683 additional electric vehicles were registered in Washington, a 37 percent increase statewide totaling 24,624 WA electric vehicles. Over the past two years the electric vehicle growth rate in WA has varied between a 34 percent and a 39 percent annualized increase.[8] Using a conservative annual growth rate of only 30 percent through June 2020 there will be over 54,000 electric vehicles registered in Washington. If the historic trend prevails through 2020, using a 35 percent annual growth rate, there will be over 60,000 WA electrical vehicles registered by June 2020. Staff recommends that PSE update its projections using recent electric vehicle sales trends for increased load due to electric vehicles in their service territory in the 2019 IRP.
6-72 **R**	**Use smaller or no electric conservation bundles.** PSE's analysis shows that a lower discount rate for residential conservation does not have a material impact on the amount of conservation chosen in the model, which was unexpected. In fact, the amount of cost-effective conservation chosen in every scenario PSE modeled stays fairly static. However, PSE identifies that creating a new smaller bundle of measures could increase the amount of conservation selected by the model. Other utilities in the northwest have solved this problem by not bundling conservation measures but rather modeling each measure separately. Staff recommends that PSE create smaller electric conservation bundles, particularly around anticipated cost-effectiveness price points, or model individual measures separately to more accurately determine the amount of cost-effective conservation available and to examine the effect of a lower discount rate for residential conservation in the 2019 IRP.

[8] WA Electric Vehicle registration analysis provided by county from WA DOT.

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6-82 through 6-87 **R** **R**	**Leverage expertise in estimating cost of carbon abatement.** PSE's analysis of the costs of varying carbon abatement methods was a worthy endeavor, particularly in light of the utility's commitment to cutting carbon emissions in half by 2040. The IRP is an appropriate vehicle to help identify the best way to decrease the Company's carbon footprint. There are numerous ways this analysis could be modified to be more useful in identifying the lowest-reasonable cost method of reducing carbon emissions, and to improve confidence in the results. Uncertainties around the best way to conduct this analysis exist, and PSE should consult with the IRP advisory group to help answer questions where they can provide insight and expertise. Carbon emissions cross borders and jurisdictions; however, an entity's decision to reduce the pollutants it emits cannot wait on the actions of neighboring entities. Staff recommends PSE take advantage of the expertise offered in the IRP advisory group, in addition to PSE staff, to identify modifications that will produce a more robust analysis in the 2019 IRP. Please see additional Staff comments on Chapter 6 and on Appendix K below for specific recommendations to improve PSE's modeling of carbon costs in the 2019 IRP. **Increase clarity of carbon cost abatement curve analysis.** Traditional marginal abatement cost curves (MACC) either look at the abatement cost of measures or policies in a given year, but rarely combine the two into a single curve. That is because the individual reduction options are viewed as additive, and measures often completely overlap with policies. In its MACC, PSE includes both renewable resource measures (e.g., 300 MW solar Central WA, 300 MW wind SE WA) and policies (e.g., 50 percent RPS). This is understandable, because PSE is trying to provide the Commission, stakeholders, and the public a single MACC curve of the most debated greenhouse gas reduction options. Unfortunately, the IRP does not explain if the measures and policies are overlapping. For example, it is not clear if the 50 percent Washington RPS policy option includes or excludes the measures 300 MW Wind (SE WA) and 300 MW Solar (Central WA). The inclusion or exclusion of these two measures will have a cost impact on the policy option. If the measures are included in the policy option, the MACC will include the same measure twice. If the measures are excluded from the policy option, it will make the policy option look less cost-effective as it strips out the lowest-cost measure. To enable a reader to understand the MACC, PSE's narrative text needs to describe the basic conditions in which the measures would be deployed. For instance, PSE shows that building 300 MW of Eastern Washington solar reduces GHG emission at nearly the same cost per unit as the closure of Colstrip Units 3 and 4. PSE states that the solar output displaces natural gas and coal-fueled generation. However, PSE does not describe in what proportions those are displaced on an annual basis or how much of each resource is displaced in the spring, summer and early fall-solar's high output periods. This type of information paired with an explanation of costs could be used to explain why PSE's results differ from the results of the Northwest Power and Conservation Council's 7th Power Plan.

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	Staff recommends that PSE refine its MACC in the next IRP by either examining only measures or only policies, or separating the two, and to share its core assumptions and a descriptive narrative, including the discount rate applied to each measure. We encourage the Company to continue including analysis on the potential issues with certain measures, as it did for the Retire Colstrip 3 and 4 in 2025 policy measure.
Ch. 7	
7-50 **R**	**Use smaller or no natural gas conservation bundles.** Similar to the electric analysis noted above, PSE's analysis of the effect of using a lower discount rate for residential natural gas conservation was "muted due to the "lumpiness" of the supply curve." An alternative would be to create smaller cost bundles for gas conservation measures to smooth out the lumpiness that masks the effect of a lower discount rate model input. Staff recommends that PSE create smaller gas conservation bundles or model individual measures to examine the effect of a lower discount rate for residential conservation in the 2019 IRP.
Ch. 8	
8-14 **R**	**Update energy delivery performance criteria to reflect a modernized grid.** PSE states that "[p]erformance criteria lie at the heart of the process and are the foundation of PSE's infrastructure improvement planning." Figure 8-5 shows the current, traditional performance criteria used by PSE's gas and electric system infrastructure planning staff. These criteria reflect performance of a legacy system for safety, reliability, and regulatory compliance, and are critical to retain for ongoing service to PSE's customers. However, these legacy performance criteria do not reflect the fact that the electric industry is undergoing fundamental changes such as grid modernization and the emergence of a smarter grid that PSE and other utilities are rapidly embracing. PSE's movement to a modernized grid is clear from their adoption of advanced metering infrastructure (AMI) to replace the current automated meter reading (AMR) infrastructure. However, it is unclear how AMI meters or other grid modernization efforts will be systematically leveraged to manage the grid more efficiently, or more to the point, what performance criteria will be used to judge these upgrades to the distribution system. To evaluate alternatives in the development and operation of a modernized grid, performance criteria for electric and gas delivery must be added to the legacy list of performance criteria. Staff recommends that PSE start working to determine how new or improved capabilities made possible through grid modernization are reflected in the grid performance criteria listed in Figure 8-5 in the 2019 IRP and that the revised performance criteria become a standard part of transmission and distribution planning.

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8-18 **R**	**Develop prototypical distribution circuits to roll-up to IRP analyses.** In evaluating contemplated distribution system alternatives, it would be useful to strategically create a suite of prototypical PSE circuits. The development of prototypical circuits could engender a methodology for streamlining the examination of individual candidate circuits or groupings of circuits with similar characteristics. Not every circuit needs detailed examination and analysis, and PSE currently performs screening to choose target circuits for analysis. Currently there is no roll-up of potential distribution costs and benefits by prototypical circuit groups that is useful to the IRP process. Staff recommends that PSE include consideration of prototypical distribution circuits as an additional activity leading into the 2019 IRP analysis. This will set the stage for providing enhanced modeling inputs to future IRP process.	
8-20 **S**	**Create a routine public review process for distribution and transmission planning.** PSE explicitly recognizes in this IRP the need for increased transparency in their distribution and transmission public processes and Staff agrees with this assessment. To address this need, and to be useful for the 2019 IRP, Staff recommends that PSE convene a standing stakeholder distribution and transmission advisory group no later than Spring 2018. This distribution and transmission advisory group would provide external review of short-term and long-term PSE distribution and transmission plans, including assumptions, inputs, analyses, and findings. The distribution and transmission advisory group would examine PSE's methods and results of evaluating transmission and distribution potential projects based on an expanded performance criteria for a modernized grid as mentioned above. The advisory group members could have a role similar in nature to the existing conservation advisory group that includes representation of broad stakeholder interests. The results would increase public transparency, assist PSE in improving its modeling inputs to the IRP process, and provide enhanced vetting of specific transmission and distribution projects. In working with this advisory group Staff encourages PSE to model a broad suite of distributed energy resource potential opportunities and development of methods to integrate cumulative impacts into IRP planning at the system level. Because of the delay in submitting the final 2017 IRP and the time-critical nature of an early start to this process for the 2019 IRP, Staff recommend that PSE supplement the 2017 IPR filing with the following information as soon as possible: ○ how PSE plans to roll up distribution energy resource analyses to system level impacts, and ○ when PSE will create an advisory group for distribution energy resource planning, and its proposed membership and role in terms similar to the existing conservation advisory group.	

Chapter, Page #, Action	Comment **Actions: S – Supplement to 2017 IRP; R – Request for 2019; G - General Comment**
8-30 through 8-53 **R**	**Energize Eastside transmission build public process.** PSE's 2017 Integrated Resource Plan Work Plan (Work Plan) states a commitment to an improved stakeholder process.[9] However, the Work Plan did not initially include PSE's system transmission and distribution planning as a specified topic for a needs assessment or, or as a topic warranting public review, even though the Company was aware of ratepayer and community interest in the Energize Eastside project.[10] Over the eight months of the IRP process, PSE received requests from the Coalition of Eastside Neighborhoods for Sensible Energy (CENSE) and other interested persons to include a thorough discussion of the system transmission analysis. In response to PSE's filing for an extension of its IRP filing due date, Don Marsh on behalf of CENSE requested PSE be required to examine Energize Eastside.[11] Mr. Marsh cited both WAC 480-100-238(3)(d) and the Commission's PSE 2015 IRP acknowledgement letter and attachment that affirms PSE's obligation under the IRP rule.[12] Staff believes that PSE's delay in beginning an analysis of PSE transmission and distribution needs within the IRP process was avoidable and thus adversely affected PSE's ability to satisfy stakeholders' need for transparency. For future projects and IRPs, this issue could be addressed by the creation of an advisory group focused on transmission and distribution planning, as recommended in the previous Staff comment.
8-30 through 8-53 **R**	**Energize Eastside need analysis.** As stated above, the IRP must include a needs assessment of the transmission and distribution system. During the course of the IRP process, PSE provided a number of studies in support of the reliability need it identified and potential alternative solutions to the Energize Eastside project.[13] However, the time allocated by PSE to discuss these and other studies during the IRP advisory group meetings was not sufficient to examine the studies in detail. This left some basic questions about the studies' assumptions, methodologies, and conclusions unresolved. For example Staff concerns include a lack of narrative in the IRP regarding: • The effect of the power flows due to entitlement returns on the need for the Energize Eastside project. • The reason for, and effect on the need for the Energize Eastside, of modeling zero output from five of PSE's Westside thermal generation facilities. • PSE's choice not to provide modeling data to stakeholders with Critical Energy Infrastructure Information clearance from FERC.

[9] "The 2017 IRP public participation process will improve transparency and meeting structures to make better use of stakeholder's time while still gathering the necessary input to inform the IRP." 2017 Integrated Resource Plan Work Plan, July 14, 2016, page 2.
[10] The PSE Work Plan included an appendix on "Regional Transmission Resource" that covered transmission needs to deliver generation capacity to PSE's system, an important but distinctly different needs assessment from the "system transmission planning" for its own balancing area. 2017 Integrated Resource Plan Work Plan, July 14, 2016, page 6.
[11] Petition to extend the date for filing of 2017 Integrated Resource Plan, March 15, 2017 and Stakeholder Participation in Puget Sound Energy's Integrated Resource Plan, on behalf of CENSE.org, from Don Marsh, UE-160918, March 30, 2017.
[12] Stakeholder Participation in Puget Sound Energy's Integrated Resource Plan, on behalf of CENSE.org, from Don Marsh, page 1, UE-160918, March 30, 2017.
[13] PSE 2017 IRP, page 8-34.

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R	• Resolution of the effect of PSE's load assumptions on the need for Energize Eastside Project. The IRP process is specifically structured to allow public discussion and inquiry, including a thorough examination of the analysis supporting a conclusion of need. This is an area where PSE can improve. In describing the status of the Energize Eastside Project with respect to its 2017 IRP, PSE states, The needs assessment and solution identification phases of this project have been completed. Currently, the project is in the route selection and permitting phases.[14] The IRP should have spoken in detail about questions of how conclusions are drawn in studies supporting a finding of need. For instance, it is still not clear if a joint utility analysis of all available transmission and potential interconnections in the Puget Sound region might solve the Energize Eastside reliability issues. Whether PSE has engaged in such analysis or discussions remains unclear to Staff, and would have been better answered in the IRP. Staff recommends that PSE's next IRP provide greater detail of its analytical reasoning, and a thorough explanation of the company's choices in its selection of inputs and modeling assumptions, especially for controversial projects. This groundwork would establish a better record for support, and would improve transparency. Both of these outcomes are key functions of the IRP. Staff believes that an advisory group focusing on distributed energy resources should be created and would help to serve this purpose. Staff lastly recommends the Commission recognize PSE's work on several potentially ground-breaking alternatives to the Energize Eastside project.[15] PSE modeled battery storage as an alternative to the Energize Eastside project. Though the cost and scale of the alternative were made them unattractive, the Company embraced analysis of new types of resources. PSE also reviewed the potential to ramp up targeted conservation to delay the build out of the Energize Eastside project. Indeed, over the decades conservation has played a significant role in delaying the reliability need for the Energize Eastside project first identified in 1993. We are encouraged to see PSE engage the topic of targeted conservation.
App. A	
R	**Continue improving the public process.** PSE has made significant progress improving the public process during the development of this IRP. Staff acknowledges the difficulty in presenting large amounts of technical information to participants with varying degrees of knowledge and interest about particular issues. The addition of a third party facilitator and an internal process manager significantly improved the identification of next steps and action items, protocols for timely PSE responses, and a more inclusive online record, which all contributed to the usefulness of the stakeholder process. Staff recommends PSE continue to make improving the public process a priority during the development of the 2019 IRP.

[14] PSE 2017 IRP, page 8-30.
[15] PSE 2017 IRP, page 8-41.

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App. E	
E-12 **R**	**Gas peak day standard.** For the next IRP, Staff recommends that PSE consider, with advisory group input, if it is time to update the gas peak day standard adopted in the 2005 Least Cost Plan.[16]
App. G	
G-4 **G**	**Increasing market risk exposure.** The IRP states, "While uncertainties remain, there are also reasons for increased confidence. So, while there is still some level of risk to PSE in relying on wholesale market purchases in order to meet resource need, this risk appears to be significantly reduced from the level presented in the 2015 IRP…" Staff does not share this view of a reduction in risk in the market and strongly cautions PSE on both its directional sense of the risk of relying on the market for capacity and its current level of risk exposure to the market inherent in its preferred portfolio. Staff develops its view of PSE's current market position from the perspective of the last two decades of resource development in the Northwest and a regulated utility's core obligations to secure resources to meet demand. Beginning around the turn of the century, independent power producers added considerable generation capacity in the Northwest region that went unsubscribed by any load-serving entity and, subsequently, became surplus in the region. This provided load-serving utilities a temporary opportunity to pursue a least-cost strategy of reliance on the market to complete their capacity needs. The market capacity surplus is now dwindling and independent developers show no desire to add capacity resources to the region without a contract from a load-serving utility. The market strategy that a decade ago posed little risk now carries increasing uncertainty and risk. In contrast to the short-term strategy described above, PSE as a regulated utility has an obligation to provide capacity to meet its system demand. Speculating in the market to meet its resource need in an attempt to achieve a capacity resource cost lower than the acquisition cost of a long-term capacity resource is not necessarily good utility practice. Due to the uncertainty and open-ended risk now appearing in the capacity market over the forward looking 5-year timeframe for acquiring new capacity resources, Staff is concerned that a capacity short position that was previously a reasonable least-cost strategy is now crossing the threshold into a speculative position. As part of its demonstration of prudent utility action, we emphasize that PSE is responsible for considering market-volatility risks and the risks it imposes on PSE's power costs as a result of not acquiring fixed-cost generation assets or demand-side resources for meeting customer demand. PSE's 20-year capacity need and resource plan does not show a path to closing out PSE's reliance on the market for its capacity resource needs.[17] However, in all three of the resource adequacy (RA) studies described in the IRP, the direction of resource adequacy beyond 2021 is clear: capacity markets are likely to fall short of meeting the RA standards. Unfortunately, the IRP does

[16] Least Cost Plans were forerunners to IRPs.
[17] 2017 PSE IRP, page 6-12, 1-9, and 2-6.

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	not expressly model or address market prices that can result from a tight capacity market.[18] Such analysis is arguably very difficult to perform in an IRP setting, but from theory and historical experience demand will be inelastic, leading to very high costs for purchasing capacity from a tight market. Without a firm analysis that can establish a reliable boundary for those potential costs, the absence of a plan for eliminating reliance on market purchases over the 20-year plan carries excessive risk. Therefore, Staff recommends that PSE diligently pursue and model IRP alternatives to the historic heavy reliance on market resources to satisfy medium-term and long-term capacity needs.
G-18 **R**	**Spot market size in wholesale market risk analysis.** On page G-18, PSE notes that it included a maximum of 3,400 MW of spot market imports in its scenarios, even though the Northwest Power and Conservation Council assumes maximum availability of 2,500 MW for on-peak and 3,000 MW for off-peak. Staff recommends that if this input assumption continues the Company explain in the 2019 IRP what prompted PSE's decision to include in its modeling assumptions elements that diverge significantly from those assumptions made by other regional entities.
G-31 through G-32 **R**	**Reliability Metrics.** The IRP relies on the use of the Loss of Load Probability (LOLP) metric as the primary metric for determining resource adequacy (RA). The IRP discusses two additional metrics for assessing RA. The Expected Unserved Energy (EUE) resource adequacy metric is a quantitative measure of the magnitude of load curtailments. The Loss of Load Expectation (LOLE) metric, also called the Loss of Load Hours (LOLH), provides information about the duration of the curtailment events. The IRP concludes, "…the concept of supplementing and/or replacing the LOLP metric as a capacity planning standard deserves further attention; the Company will therefore continue to pursue those discussions at the regional level before bringing the issue to the Commission." In light of PSE's choice to remain short of capacity resources in its resource portfolio and rely on the existence of a capacity market surplus to meet its obligation to serve load, a suite of comprehensive RA metrics is called for and frequent, ground up re-examinations of its RA conclusions and market risk exposure needs to be routinely performed. LOLP, EUE, and LOLE all provide unique group-heuristic measures of the failure to serve load. Staff recommends PSE adopt the use of EUE and LOLE along with its use of LOLP. In doing so, PSE will need to work with regional entities and entities in the western portion of the WECC to develop its data base, assumptions and methodologies for each approach to measuring RA. It will also need to develop an explicit method for balancing the weight given to each approach. Staff will work with PSE in this endeavor but responsibility for developing a method and the weighting remains the Company's responsibility.

[18] The IRP uses an expansion model that adds capacity resources to prevent capacity shortages from thwarting price formation in the model.

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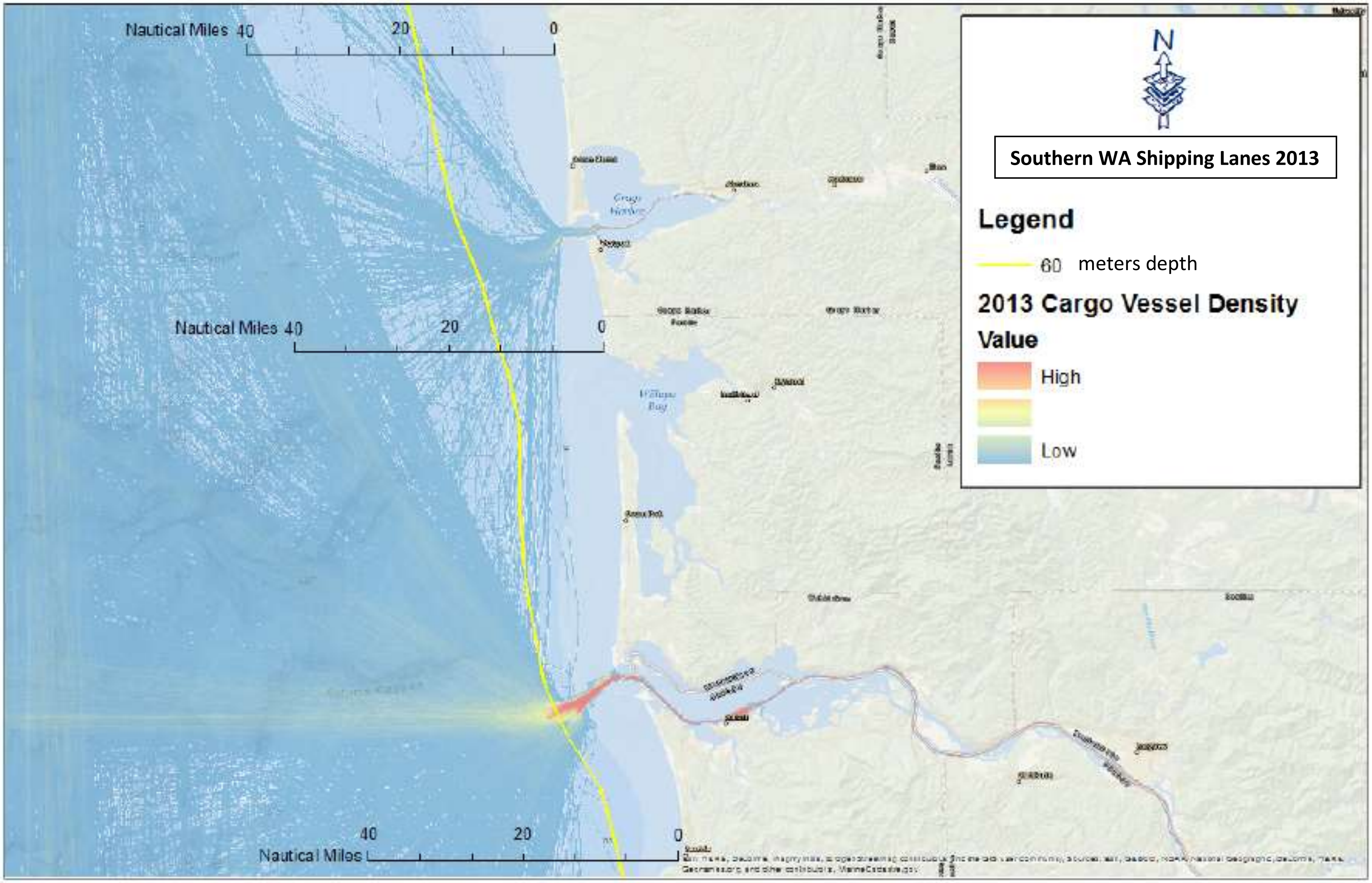
	PSE performed a re-examination of its 2015 IRP analysis of RA. We recommend PSE perform this analysis every IRP along with the new RA metrics recommended above. In view of PSE's choice to perform a re-evaluation rather than a complete set of new analyses, PSE should examine RA metrics and its market risk exposure between IRPs. In addition, Staff recommends that the IRP advisory group be informed as progress goes forward and the methods, process, and results are decided in the 2019 IRP.
G-33 **R**	**Modeling market participant behavior.** PSE states that whether market participants will change their behavior during a peak event is an important assumption. The models used to build this analysis assume far more transparency and rationality on the part of market participants than exists in reality. Staff recommends that PSE examine the assumptions of rational behavior during peak weather conditions by analyzing any available historical market behavior in the region during large weather events, and use those findings in the 2019 IRP modeling.
G-32 **G**	**California Imports.** The IRP recognizes the firm import capacity of the CA-NW intertie along with the uncertainty of de-rates to that firm capacity, especially during winter months when PSE's load peaks. The IRP states, "Regional resource planners are continuing to assess the amounts of capacity that could reliably be imported from California to help meet PNW winter peak loads…" that could reliably be imported from California to help meet PNW winter peak loads…" Considering PSE's dependence on market resources and its existing capacity contract delivered via the NW-CA intertie, Staff recommends that PSE take a lead role in engaging and motivating the necessary entities to collect the data and perform the analysis necessary to improve the accuracy of the firm import capacity of the NW-CA intertie used in RA models. Though we view PSE's statement that it will "actively work with the NPCC, BPA, PNUCC and other regional stakeholders to improve the accuracy of regional resource reliability assessments" to include issues of the NW-CA intertie, Staff expects PSE to explicitly state its need to take an active and leading role in improving the analysis of the import capacity.
App. H	
R	**EIM and operational flexibility.** Staff appreciates the summary of PSE's current operational flexibility. The PLEXOS model's capability to perform analysis at the 5-minute level is a positive step towards achieving the temporal granularity needed to better consider distributed resources such as energy storage. However, this analysis looks at PSE's operations before joining the EIM. Staff recommends that in the next IRP an update to this appendix describes how EIM have impacted PSE's procurement of contingency reserves, balancing reserves, and ramping capability.
App. J	
R	**Access to third party models.** At Staff request, PSE supplied additional time and discussion that allowed Staff a deeper understanding of Navigant's conservation potential assessment. We ask PSE to continue looking for opportunities to provide Staff additional access to consultants' technical models in order to increase the transparency of consultant's work that ultimately is integrated into the IRP process.

Chapter, Page #, Action	Comment	Actions: S – Supplement to 2017 IRP R – Request for 2019 G - General Comment
App. K		
R	**Market price of carbon.** PSE has worked to model carbon regulation and carbon pricing in its economic forecasting of the viability of the Colstrip generation units for more than a decade. Despite PSE's IRP work and any other efforts PSE has made to understand the economics of Colstrip Units 1 and 2, PSE failed to predict the closure of those units resulting in more than $100 million in unrecovered investment and $100s of millions in underfunded remediation costs. PSE's ability to manage its risk exposure from Colstrip Units 1 and 2 was clearly inadequate. PSE inaccurately modeled Colstrip as a long-term stable resource in its IRP assumptions, when in fact it was not. To improve PSE's understanding of the market risk to Colstrip Units 3 and 4 and provide PSE a potential hedge against those costs, Staff recommends PSE solicit an RFP where counter parties bid a price to assume the cost of any CO_2 price imposed on Unit 3 and 4 emissions over PSE's expected life for those two units. PSE does not have to guess at the effects of potential regulation. Large numbers of market participants are determining a cost and price today. The price bid to assume the liability would reveal the liability PSE is proposing to impose on ratepayers by continuing the operation of the plant. If the bid prices are too high for the units to remain economically viable, PSE can request a determination that the units are no longer used and useful and depart from the plant operating agreement. If, however, the cost of such insurance is economical to purchase then PSE can purchase the insurance and continue to operate the units with reduced risk. Staff recommends that PSE examine this alternative method of carbon pricing and the economies of continued operation of Colstrip Units 3 and 4.	
App. L		
R	**Measuring the benefits of energy storage.** Staff acknowledges that the purpose of this appendix is currently characterized as qualitative background information. However, as PSE gains experience with energy storage on its system, Staff recommends that in the 2019 IRP this appendix include quantitative analysis examining energy storage impact on PSE's system that will eventually be useful in IRP modeling.	

Attachment A – 2013 Shipping Lanes off Washington Southern Coast



Green Energy Institute (GEI)

Email Dated 5/7/2018

SIERMAN Jason * ODOE

From:	Amelia Reiver Schlusser <ars@lclark.edu>
Sent:	Monday, May 7, 2018 1:55 PM
To:	SIERMAN Jason * ODOE
Subject:	Re: Reminder: May 15 RAC Meeting re: EFSC CO2 Standards
Attachments:	GEI input-EFSC CO2 RAC Meeting May 2018.pdf

Hi Jason,

Attached is GEI's input for the May 15 meeting. Please let me know if you prefer that I submit our input in a more formal format.

Best wishes,
Amy

On Wed, May 2, 2018 at 3:58 PM, SIERMAN Jason * ODOE <Jason.Sierman@oregon.gov> wrote:

> Hi everyone,
>
> As a reminder, please send me any input you may have regarding the (2) attached documents sooner than later. I previously mentioned a soft deadline of this Friday, May 4 (see below), but feel free to send input throughout next week as well.
>
> **Providing Input Before we Meet**
>
> To increase the effectiveness and efficiency of our May meeting, and to whatever extent possible, ***I ask that people provide me with their input via email by Friday, May 4***. I will aggregate any input I receive before May 4 and circulate that input to all the RAC members the week before our meeting. This will give everyone the opportunity to review the input of others before we meet and best prepare everyone for our discussion on May 15.
>
> And if anyone has any questions about the material, please don't hesitate to give me a call. I may be able to help explain something you're interested in providing input on.
>
> Thanks,
>
> Jason
>
> **Jason Sierman**

Green Energy Institute (GEI)

Attachment 1

(to email dated 5/7/2018)

To: Jason Sierman, Oregon Department of Energy, Energy Facility Siting Council
From: Amelia Schlusser, Staff Attorney, Green Energy Institute at Lewis & Clark Law School
Date: May 4, 2018
Re: EFSC CO2 Emissions Standards Rulemaking; Input on ODOE Draft Analyses

Green Energy Institute (GEI) input on Department's preliminary draft analysis of the 13 principles:

1. Promote facility fuel efficiency:
    - GEI: Agree with staff. The proposed CO_2 emissions standard will be more effective than the existing standard at promoting fuel efficiency to reduce emissions and any associated monetary offset fees.

2. Promote efficiency in the resource mix:
    - GEI: If additional natural gas-fired CCCT capacity is needed in Oregon, the proposed CO_2 standard should promote efficiency in the resource mix by incentivizing investments in the most efficient natural gas-fired CCCT design and technology available. Additionally, because the relative cost of compliance with the proposed standards represent such a low percentage of lifetime present value costs (less than 0.50%), it is unlikely that the proposed standard alone would encourage investments in less efficient alternative generating technologies.

3. Reduce net CO_2 emissions:
    - GEI: The proposed CO_2 standard should help incentivize reductions in both gross and net CO_2 emissions from new fossil fuel-fired power plants constructed in Oregon. If new fossil fuel-fired power plants are constructed in Oregon, the proposed standards will require the plants to indirectly reduce their net emissions by an additional 0.06 lbs. CO_2/kWh in comparison to the current standards. The proposed standard will also create an incentive to invest in the most efficient facilities possible, which will produce fewer gross CO_2 emissions than comparable less efficient facilities.

4. Promote cogeneration that reduces CO_2 emissions:
    - GEI: Agree with staff.

5. Promote innovative technologies and creative approaches to mitigating, reducing, or avoiding CO_2 emissions:
    - GEI: More stringent CO_2 standards may promote the application of innovative technologies and approaches to mitigating CO_2 emissions if available technologies and approaches are incapable of achieving meaningful emissions reductions and developers are subject to high monetary offset fees. However, this would only occur

if the costs of deploying new technologies and/or approaches at a facility are lower than the facility's projected monetary offset fees. This scenario is unlikely, given the current monetary offset rate of \$1.90/ton CO_2. A more stringent CO_2 emissions standard combined with a higher monetary offset rate would more effectively promote investments in innovative technologies and approaches to reduce CO_2 emissions. However, given recent reductions in the levelized costs of carbon-free generating resources, such as wind and solar power, it is possible that the aggregate costs to comply with the proposed standard and other state policies (such as the RPS) will create an economic incentive to invest in generating resources with no associated carbon emissions, rather than invest in high-efficiency CCCT facilities. In this event, the proposed standard would contribute to greater reductions in CO_2 emissions.

6. Minimize transaction costs:
   - GEI: Agree with staff.

7. Include an alternative process that separates decisions on the form and implementation of offsets from the final decision on granting a site certificate:
   - GEI: Agree with staff.

8. Allow either the applicant or third parties to implement offsets:
   - GEI: Agree with staff.

9. Be attainable and economically achievable for various types of power plants:
   - GEI: Agree with staff's analysis and conclusions. The estimated compliance costs associated with the proposed standards are incredibly low in comparison to projected lifetime present value costs. Additionally, by incentivizing investments in high-efficiency CCCT technologies, rather than less efficient baseload and non-baseload facilities, the proposed standard could potentially help mitigate costs resulting from future natural gas price volatility (because more efficient plants consume less fuel than less efficient plants).

10. Promote public participation in the selection and review of offsets:
    - GEI: Agree with staff.

11. Promote prompt implementation of offset projects:
    - GEI: Agree with staff.

12. Provide for monitoring and evaluation of the performance of offsets:
    - GEI: Agree with staff.

13. Promote reliability of the regional electric system:
    - GEI: As staff concluded, the proposed standards are financially achievable (considerably so) and therefore would not create an economic deterrent against constructing a new baseload or non-baseload facility in Oregon, if such a facility were necessary to support reliability within the regional electric system. GEI is not aware

of any reliability concerns associated with high-efficiency CCCT facilities in comparison to less efficient facilities.

Green Energy Institute (GEI) input on Department's preliminary draft Statement of Need and Fiscal Impact:

Based on staff's findings expressed in the draft Statement of Need and Fiscal Impact, it is essential that the Council update the CO_2 emission standards to ensure that any new fossil fuel-fired power plants constructed in Oregon are as efficient as possible and achieve further reductions in gross and net CO_2 emissions than those required under the current standards. The Department's estimated costs to comply with the proposed standards are incredibly low in comparison to total projected construction, operation, and maintenance costs over the lifetime of a regulated facility. These low compliance costs are primarily due to the current monetary path rate of \$1.90/ton CO_2, which, according to the Climate Trust's 2014 report, is insufficient to fund one ton of CO_2 offsets. The Council should therefore adopt CO_2 emission standards that are as stringent as possible given the statutory parameters.