Attachment 2

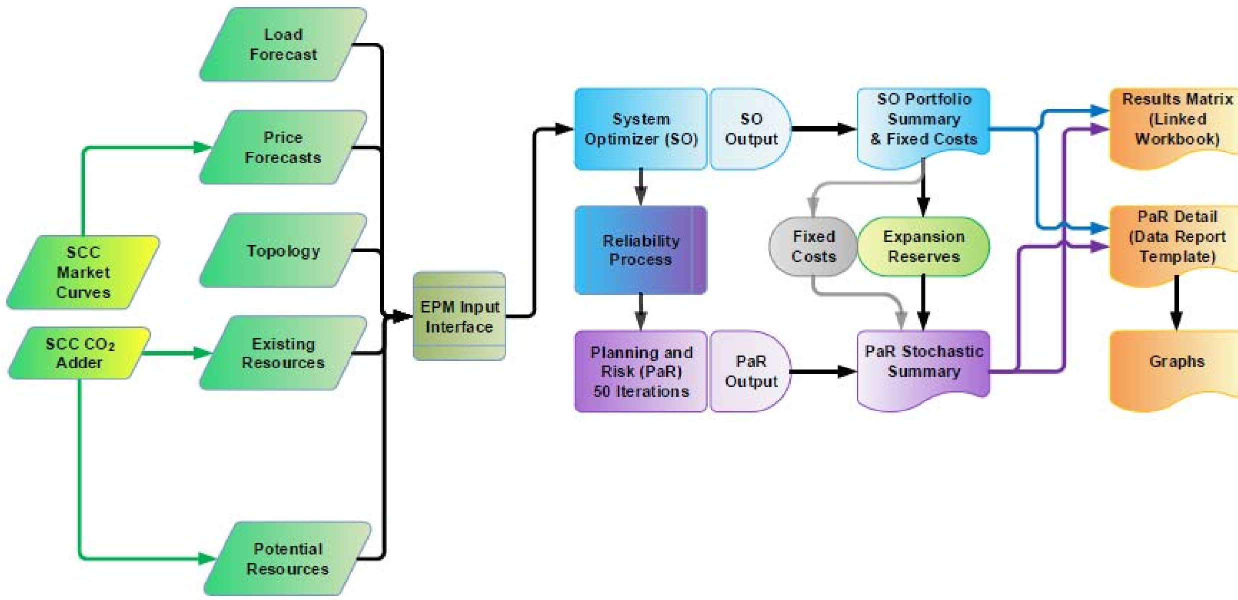
1. **Modeling Greenhouse Gas Emissions**

a. Case P18 description and modeling flow diagram Table 8.9 in the 2019 IRP specifies Price-Policy Cases, High Gas/High CO2 Results Summary. For Case P18, it would be helpful to specify the other assumptions used to develop the social cost of carbon CO2 price assumption PVRR. For example, was high gas used? Please specify if (or where) in the modeling C02 prices were included for the 1) power price forecast, if applicable, and 2) long-term capacity expansion model. In this this price-policy scenario, it is not clear where social cost of carbon is reflected in market prices and dispatch costs. A modeling flow diagram would be helpful to show the point in the modeling process where C02 prices are applied.

In case P-18, the gas price assumption is the same as in the official forward price curve (OFPC), and is thus aligned with the expected (medium) case. Social cost of carbon is accounted for in the development of market prices and is applied as a CO_2 "adder" that is applied as a dispatch cost for CO_2 emitting resources. The social cost of carbon applies throughout all phases of the study, affecting resource selection, dispatch, and the larger market price environment for the entire PacifiCorp system. Per the Washington Utilities and Transportation Commission's (Commission) recommendation, the social cost of carbon was developed from the Interagency Working Group on Social Cost of Greenhouse Gases estimate. The result is a price-policy scenario that is distinct from each of the others.

In any price-policy scenario, market prices and CO_2 prices are entered as inputs prior to running any models, and therefore the point of application is at the very beginning, affecting all subsequent model runs, both capacity expansion and stochastics. Market prices influence front office transaction (FOT) costs and purchase and sale pricing at each market node in the topology. CO_2 prices are added to the inputs describing the operating cost of each emitting resource. Note that there is no additional or distinct input for social cost of carbon. It uses the exact same inputs as for any other price-policy scenario, influencing expansion resource selection, unit commitment and dispatch accordingly.

In the process diagram below, social cost of carbon inputs are represented at the far left.



b. The utility must evaluate and select conservation policies, programs and targets. As such, has the utility run two scenarios, where the GHG emissions cost are included as either a damage cost (resource logic, add GHG (tons) * SCC ($/ton) added to "fixed O&M") or included in hourly dispatch for utility (dispatch & demand logic for new and existing thermal plants) to test the effect of policies? If yes, to aid in the comparison for conservation selected, please provide the amount of conservation and demand response selected for each scenario and specify the IRP *preferred resource portfolio* selected.

The Company did not model greenhouse gases (GHGs) as a damage cost in the 2019 IRP, as emissions are not known until after the model completes. An estimated damage cost that serves as an input to expansion resource cost would discourage emitting resources during portfolio selection, but would not affect dispatch once the resources were selected and considered active. One drawback to this approach is that even if fewer emitters are selected during capacity expansion, they would dispatch normally and perhaps higher, compensating for the reduction in selected emitters. Existing resources would not be impacted at all by this treatment.

Alternatively, if GHGs are added as a damage cost calculated after the model run on the basis of emissions, this would discourage the selection of high-emitter portfolios for the preferred portfolio, but would not allow the expansion model to see this important driver. The resulting portfolios would therefore tend toward a higher selection of emitters in every case when compared to a modeling strategy of including the social cost of carbon as a dispatch cost.

While it has limited utility, it is possible to calculate a post-model damage cost for every portfolio in the IRP by multiplying the resulting emissions by the difference between the CO_2 cost applied for that case to the new social cost of carbon CO_2 cost.

See attached file for information requested in the tables below. The responses align with and are built on information provided to WUTC staff on January 14 and Commissioner Balasbas on January 23. The information is provided for conservation forecast found in the IRP documents. As noted in prior correspondence, forecasts adjustment documented in Appendix 1 of the Biennial Conservation Plan(s) incorporate RTF adjustments, code and standards impacts to arrive at biennial conservation targets were not included since their complicates meaningful comparison between portfolios especially when capacity impacts are requested.

Information for Table 3 is not provided since PacifiCorp's IRP models demand response energy as "take and return". Energy not used during an event is not saved, but used at a different time. There are no energy savings from DR and for this reason we have not provided any data for the table.

Conservation in MWh 10 year period (aligns with EIA biennial target setting)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
2017 IRP													
2019 Progress Report: Scenario 1 (GHG emission cost modelled as a damage cost, added as fixed O&M)													
2019 Progress Report: Scenario 2 (include emission costs in dispatch)													

Peak Capacity - Conservation in MW 10 year period (aligns with EIA biennial target setting)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
2017 IRP													
2019 Progress Report: Scenario 1 (GHG emission cost modelled as a damage cost, added as fixed O&M)													
2019 Progress Report: Scenario 2 (include emission costs in dispatch)													

Demand Response in MWh

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
2017 IRP													
2019 Progress Report: Scenario 1 (GHG emission cost modelled as a damage cost, added as fixed O&M)													
2019 Progress Report: Scenario 2 (include emission costs in dispatch)													

Peak Capacity – Demand Response in MW

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	Total
2017 IRP													
2019 Progress Report: Scenario 1 (GHG emission cost modelled as a damage cost, added as fixed O&M)													
2019 Progress Report: Scenario 2 (include emission costs in dispatch)													

2. **Potential for double-counting – Are there potential issues with double counting social cost of carbon in IRP modeling in forecasting power prices or utility portfolio optimization? If yes, please identify *where* in the modeling process this may be a potential issue.**

   The Company does not perceive any double-counting in the 2019 IRP social cost of carbon modeling approach. There are three appropriate effects of the social cost of carbon price-policy scenario in case P-18: 1) the increased cost of emitting resource dispatch due to the CO_2 price adder, 2) the impact on portfolio selection due to higher operational costs of emitting units, and 3) the impact of social cost of carbon on market pricing which affects system operations generally. To the extent that the social cost of carbon increases the cost of FOTs and the cost of operating a coal unit is not considered double-counting as both effects are simultaneously expected consequences.

3. **Unspecified market purchase emission rate**

a. For unspecified market purchase and associated emissions rates, which will decrease over time under CETA, how does the utility plan to model carbon content reflect the marginal resource for dispatch? Please identify utility's current modeling input for market purchases emissions rate, including but not limited to:

- Annual regional emissions intensity average

- Hourly regional emissions intensity

- 0.437 metric tons of carbon dioxide per megawatt-hour of electricity (RCW 19.405.070) or Department of Ecology rule data.

The Company did not model a gray energy price reflecting a separate CO_2 adder to market purchases. There are several reasons for this. First, if there is to be a CO_2 adder for purchases, there must be a CO_2 credit for sales to avoid double-counting. Second, as the model is a linear optimization, it does not require the establishment of an explicit marginal resource as part of its calculations, and does not report as such. Also, the marginal resource would potentially vary in every time slice of the model.

b. Looking to the future, how should the utility plan to model carbon content in the future to properly reflect changing unspecified market purchase emission rates, which are not constant?

In future IRPs, the Company anticipates several changes to its social cost of carbon modeling, informed by discussions in ongoing workshops and clarity provided by the Commission. One change is likely to be the allocation of social cost of carbon to resources providing energy and capacity to Washington rather than the whole system. With regard to market purchases, it seems likely that the Company will need to calculate an estimated costs adder on the basis of regional intensity as indicated in response to question 3(a), above. The Company also expects to argue in favor of the sales credit indicated in the response to question 3(a), above.

c. What limiting factors in the IRP model(s) or data preclude modeling emission rates to better reflect the future emissions expected through CETA compliance planning horizon?

The major anticipated challenges at this time are determining energy and capacity contributions of all resources to Washington (which are expected to vary in every time slice of case), determining an appropriate and recursive market CO_2 rate, and isolating the costs of compliance to Washington customers. These considerations are computationally intensive, currently in flux, and will require the development of special reporting aligned with the new modeling, inputs and outputs.

4. **WECC capacity expansion model for power prices**

a. In the IRP rules, should there be additional guidance on which jurisdictions social cost of carbon applied? For example, is it across the WECC? Or, only to those entities bringing load to Washington? Alternatively, only on generation produced and imports (Washington load base)?

PacifiCorp is still discussing which jurisdictions should be subject to the social cost of carbon. Generally, a policy that minimizes rate impacts on Washington customers – while still achieving the ambitious decarbonization goals mandated by CETA – is preferable.

b. Please describe if there are any technical limitations? For example, please explain leakage risks if utilities do not apply the policy.

Based on ongoing discussion at the CETA workshops, the Company is currently assuming that in the future, social cost of carbon will be applied only to those resources contributing energy and capacity to Washington. As noted above, this will involve a computationally expensive assessment requiring material modeling and reporting changes anticipated to affect model performance. However, the Company is firmly committed to meeting these challenges and believes the attending technical challenges can be overcome.