NW Energy Coalition
Comments on and Requests
regarding the PSE 2021 IRP Webinar #5:
Social Cost of Carbon, July 21st, 2020

July 24, 2020

Elizabeth Hossner
Manager Resource Planning & Analysis

Keith Faretra
Senior Resource Scientist
Puget Sound Energy

Dear Elizabeth and Keith:

NW Energy Coalition (NWEC) appreciates the opportunity to ask questions about and make suggestions regarding PSE's approach to applying the Social Cost of Carbon (SCC), per the Clean Energy Transformation Act (CETA) and measuring upstream emissions. Our comments generally follow the order of the slides presented in the webinar of July 21st, starting with comments on the SCCC.

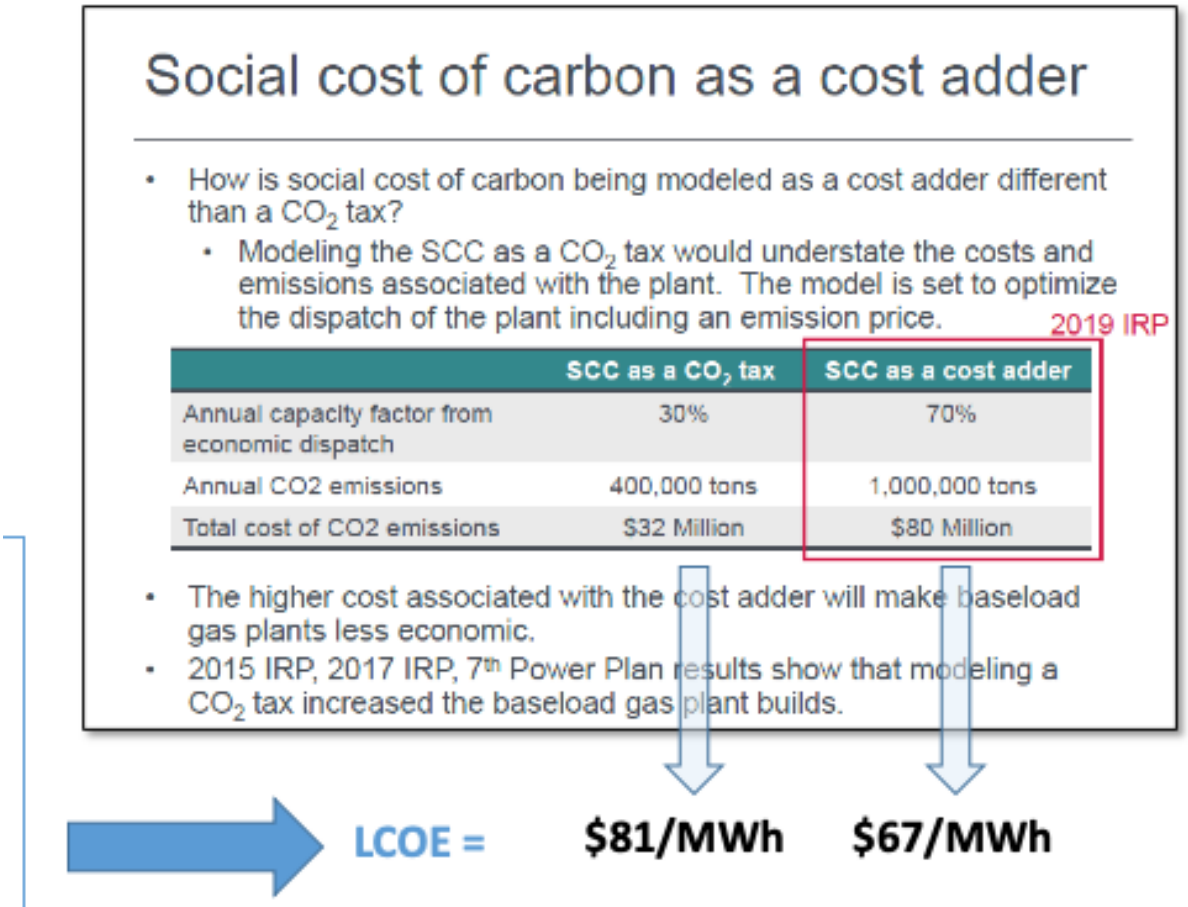
Slide 14 – first point – While it was explained the SCC is provided to program staff who apply that value to conservation measures that come out of the RFP at the time when the measures are being screened for the IRP, we would appreciate a more detailed written explanation of that methodology. Demand side resources are often bundled into groups by costs, so the SCC must be reflected in the individual price as the model is selecting those resources.

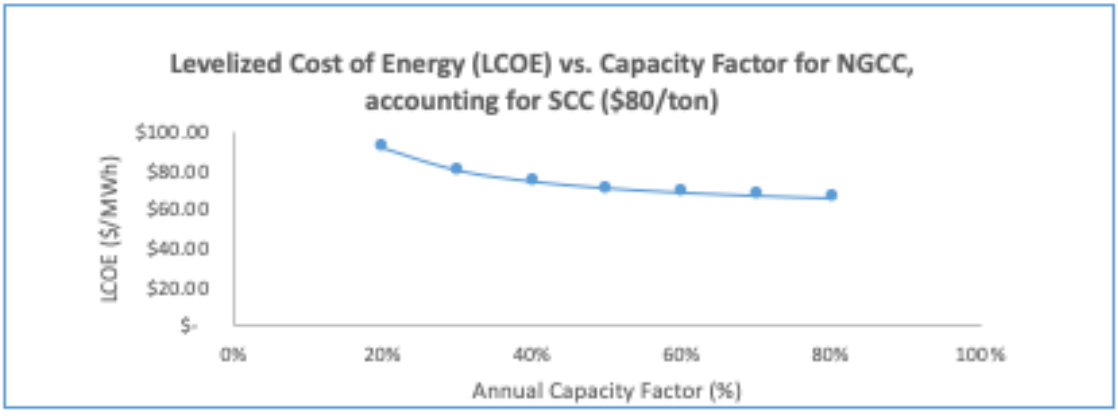
It was also stated during the presentation that the SCC is not applied to any demand side resource such as conservation or efficiency in either the long-term capacity expansion analysis or in Aurora modeling. Are other measures, such as grid controlled hot water heaters, treated the same way? How does this ensure that DSR are fairly considered compared to other choices?

Slide 14 – points 2 and 3 – We appreciate the explanation why PSE has decided to apply the SCC as a fixed cost in the resource planning, but we respectfully disagree with this approach. The purpose of requiring the SCC as a planning price is to internalize into planning decisions the external cost of emitting CO2. The SCC does not function as a tax that is passed through to customers, but as an external cost that must be incorporated in resource investment decisions.

If dispatch modeling informs resource investment choices in any way, the SCC must be included in the dispatch analysis to prevent distortions. While LCOE is not the only factor considered in choosing resources, it is an important one; accounting for SCC in dispatch modeling will reduce

a NGCC's capacity factor (all else being equal), which will increase overall cost on a levelized basis. On a per MWh basis, including the SCC in only the investment analysis and not in modeled dispatch will skew the economics of two identical resources. This is illustrated by using the chart PSE provided on Slide 20;





Data sources: NREL 2019 ATB NGCC with adjustments to capacity factor; emission rate = 0.42 metric tons/MWh (based on Goldendale historical operations and EIA)

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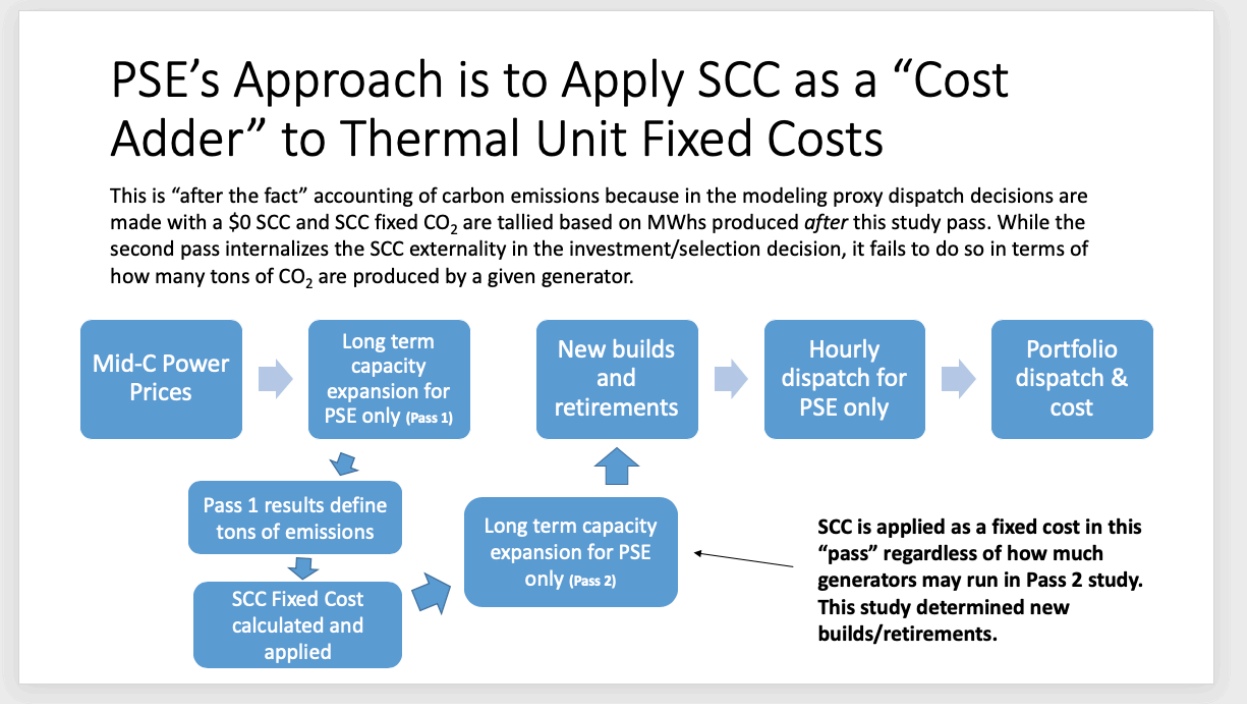
Treating SCC as a fixed cost may raise the capital cost of the certain thermal resources, but may well lower levelized costs (a per MWH measure). The model's economic "incentive" is to add thermals and run them more because they become more economic the more they run, as their upfront fixed cost is spread over more and more MWhs. By excluding SCC from dispatch modeling, it is more likely that certain new and existing thermal resources will *run more* than if the SCC was accounted for in their dispatch costs

As a result, the incorrect price signal is being sent to the model, especially when selecting against demand-side resources. Consequently, there will be no way to test if higher amounts of demand-side resources will result in a lower cost/lower risk portfolio.

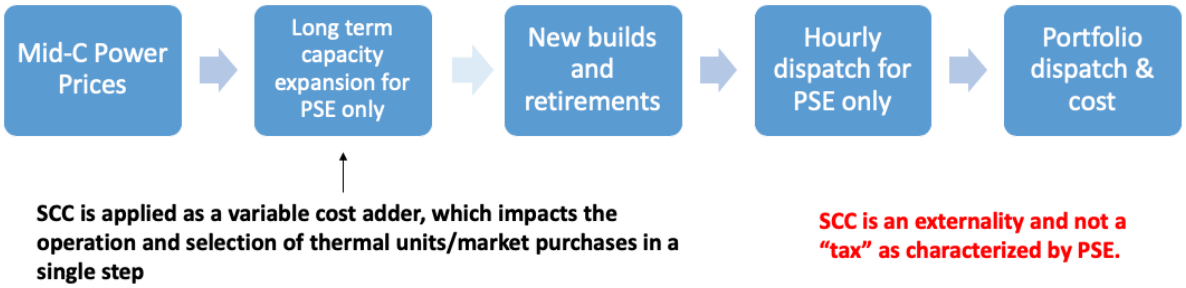
PSE's agreement to run a scenario incorporating the SCC in dispatch will allow a comparison between treating SCC as a fixed cost and treating SCC as a variable cost to see if that makes a difference in the resources chosen for the portfolio. This is how we understand PSE's proposal:



We suggest the following as an alternative to the methodology depicted in Slide 21:

An Alternative Approach is to Apply SCC as a Cost Adder to the Variable Cost of Thermal Generators

This approach allows the externality (SCC) to be internalized into the operational and investment decision of the generator or power purchase. Incorporating the cost of the externality – carbon emissions – based on the SCC will cause a dispatch that relies on thermal generation less and makes thermal generation more expensive. A high variable cost and low(er) generator output means a thermal unit will have more difficulty recovering its fixed capital costs, which are unchanged. This fully internalizes the SCC externality.



Slide 17 – first point – this needs to be corrected to state "….at the lowest REASONABLE cost possible to ratepayers." Least cost is not defined as singularly the lowest cost, but the lowest cost considering a number of factors, per 19.280.020(9) and (11).

Slide 18 – Instead of adding the SCC to the fixed plant costs, we would argue that SCC should be added to variable costs, dispatch modeling and unspecified market purchases. We will trust that is what the second scenario PSE committed to run will do.

Slide 19 – out of curiosity, is there some reason the results in the fourth column do not match what the results would be multiplying the tons of CO2 times the SCC in $/ton? They are not far off, so is the difference due to rounding?

Slide 21 – it is still not clear how DSR are incorporated into this methodology. Please explain more fully.

Slide 24 – the conclusions listed on this slide are described as the conclusions that were presented in the December 11, 2019 Power point. However, this list leaves off the third conclusion

3. "With the CETA renewable requirement, significantly more conservation is added than the 2017 IRP. "

Please explain why this conclusion was not included in the current presentation.

While we would generally agree that an RPS standard is an effective driver of change, it seems a well-designed methodology for applying the social cost of carbon could have a significant effect on resource choices, especially of demand side resources and conservation.

Upstream Emissions:

Slides 29-35 – NWEC believes that PSE should use the most current and well documented scientific and technical analysis of upstream methane emissions. Concerning the sources cited by PSE, neither the Canadian analysis using the GHGenius model, nor the EPA analysis for the US using GREET, are consistent with current observational data and analysis, and almost certain to understate the upstream emissions rate by a considerable margin.

Our concerns are fully documented in a recent letter to the Northwest Power and Conservation Council (attached). In particular, we are concerned that the Canadian values greatly understate the upstream emissions for development and production areas in northeast British Columbia and northwest Alberta region that are the source for much of the natural gas used in Puget Sound region power plants as well as direct use. Several recent peer-reviewed studies cited in our letter summarize both field surveys and summaries of data provided to provincial regulators.

Further, in the regulatory review of both the Tacoma LNG project and the proposed Kalama methanol facility, several organizations with significant expertise have reviewed the analysis by PSCAA relying on the same Canadian provincial sources and submitted extensive comments. In that regard, we attach a December 2018 letter from the Stockholm Environment Institute (SEI) US Center summarizing concerns about the vintage and limitations of the data and analytical methods used in the Canadian provincial assessments.

The PSCAA values referenced on Slide 34 are 153.21 g/mmBtu for GHGenius (Canadian gas) and 221.05 g/mmBtu for GREET (US gas). According to the lookup table in the NW Council staff analysis (attached) at Tab 1, line 54, this approximates emissions rates of 0.85% and 1.25% respectively.

In comparison, the EPA mid estimate is 1.82% (Council analysis, Tab 1, cell W24), and the EDF mid estimate is 2.84% (cell W23) and low estimate is 2.47% (cell X23).

We recommended, and the NW Council staff proposed, to use the EDF low estimate for US gas (2.47%) because the EDF-led methane emissions study is by far the most substantial and extensive ever conducted. It involves a wide range of engineering, gas chemistry and atmospheric science experts, extensive use of direct and indirect data acquisition, and integrated analysis with results presented in numerous peer reviewed publications. While the project is continuing, the summary publication by Alvarez et al. ("Assessment of methane emissions from the U.S. oil and gas supply chain," Science, doi: 10.1126/science.aar7204, also

attached) provides a comprehensive assessment including the recommended emissions metrics mentioned above.

In conclusion, we recommend that PSE use the EDF low emissions rate of 2.47% as the most supportable overall value for aggregate upstream methane emissions from both US and Canadian sources. We also recommend that the Canadian values be further refined going forward, through consultation with relevant experts, especially those conducting the peer reviewed studies of Canadian methane emissions, to gain a consensus expert view on an appropriate upstream emissions rate for natural gas sourced in British Columbia and Alberta.

Joni Bosh
joni@nwenergy.org

Fred Huette
fred@nwenergy.org

NW Energy Coalition
811 1st Avenue, Suite 305
Seattle, WA 98104

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