NW Energy Coalition
for a clean and affordable energy future

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Docket UE-191023

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Mark Johnson, Executive Director/Secretary
Washington Utilities and Transportation Commission
1300 S. Evergreen Park Dr. S.W., P.O. Box 47250
Olympia, Washington 98504-7250

Re: NW Energy Coalition's Responses to Questions Relating to Clean Energy Implementation Plans and Compliance with the Clean Energy Transformation Act

Dear Mr. Johnson:

The NW Energy Coalition (Coalition) submits the following written comments in UE 191023 pursuant to the Notice of Opportunity to File Written Comments dated January 15, 2020. These comments respond to questions posed in that notice.

The Coalition is an alliance of more than 100 organizations united around energy efficiency, renewable energy, fish and wildlife preservation and restoration in the Columbia basin, low-income and consumer protections, and informed public involvement in building a clean and affordable energy future.

Clean Energy Implementation Plans (CEIP)

1. CETA stresses the need to maintain system reliability and resource adequacy. RCW 19.405.060(1)((a)(iii) requires that the specific actions taken in a CEIP be consistent with the utility's resource adequacy requirements. What information should utilities include about their system reliability and resource adequacy in the CEIP? For example, should the utilities include detailed information about the resource mix it plans to use to meet system reliability and resource adequacy and how each resource type contributes?

Utilities must present detailed information about the resource mix it plans to rely on to meet system reliability, including data sources, analysis methodologies, calculations and assumptions. Resource adequacy should not rely just on supply side generation resources, but on the management and integration of demand side resources as well. Integration and coordination of all resources will keep costs down and to ensure resiliency as well as reliability.

Clean Energy Action Plans (CEAPs) under RCW 19.280.030(2)(c) and (d) explicitly require a utility to identify potential cost-effective Demand Response (DR), load management programs, Renewable Resources (RE), non-emitting resources (NE) and Distributed Energy

Resources (DERs) and evaluate how each identified resource may, if acquired, be expected to contribute to meeting the utility's resource adequacy requirements in each ten-year CEAP. Further, CETA requires that those ten-year analyses be translated into specific targets for Energy Efficiency (EE), DR and RE in each four-year Clean Energy Implementation Plans (CEIPs).

Additionally, the methodologies for measuring resource adequacy should also be clearly identified and explained, along with accompanying analyses, in the CEIP.

CEIP Targets

2. RCW 19.405.060(1) requires that by January 1, 2022, and every four years thereafter; each electric investor-owned utility must develop and submit to the Commission a four-year CEIP for the standards established under RCW 19.405.040(1) and 19.405.050(1). The plan must propose specific targets for energy efficiency, demand response, and renewable energy. The plan must also propose interim targets for meeting the standard in RCW 19.405.040(1) prior to 2030 and between 2030 and 2045.

a. ***Should the rules provide that specific targets must be defined cumulatively for each four-year period, or identified annually, within the four-year compliance period?***

   The specific targets required for renewable energy, energy efficiency and demand response should be annual targets.

b. ***Should the Commission require utilities to identify interim targets by resource type or some other metric(s), such as percentage of sales to customers from non-emitting generation and renewable resources?***

   The interim clean energy standard targets should demonstrate progress toward meeting the 2030 and 2045 targets in RCW 19.405.040 and RCW 19.405.050 over each four-year period. Interim clean energy standard targets should be reported as percentage of sales and should be clearly identified by resource type at a minimum by either renewable energy resource or non-emitting resource. Ideally, generation would be reported at a finer level of detail that specifies the type of electricity resource (e.g. solar, wind, etc.). Interim clean energy standard targets should also be explicitly linked to the specific RE, EE and DR targets identified in 2(a) above. For renewable resources, the link is clear, however, for energy efficiency and demand response it will be useful to summarize how the acquisition of those resources has influenced the utilities clean energy standard needs and compliance.

c. ***Should the Commission require that interim targets be defined cumulatively or annually for the years prior to 2030? For the years between 2030 and 2045?***

Interim clean energy standard targets should be established for each four-year period between 2022 and 2030 and 2030 and 2045. The interim targets should be used to illustrate the progress the utility plans to make to achieve the targets, as stated in the answer to b. above. While the targets should be cumulative targets for each four-year period, reporting on actual compliance should provide electricity generation information on an annual basis.

3. ***RCW 19.405.060(1)(c) requires the Commission to approve, reject, or approve with conditions the CEIP and associated targets after a hearing. With conditional approval, the Commission may recommend or require more stringent targets. Are there circumstances in which the Commission can and should recommend, rather than require, more stringent targets? If so, when should the Commission recommend more stringent targets and on what basis could and should the Commission not require more stringent targets?***

CETA gives the Commission clear authority to require more stringent targets than those proposed in a CEIP by a utility. The following are some conditions under which it would be necessary or advisable for the Commission to either recommend or require more stringent targets:

1) if the proposed targets appear inadequate to meeting the statutory standards, or

2) if the proposed targets are so low that they leave too high a compliance burden toward the end of a compliance period, increasing the risk of the utility either not being able to comply or increasing the risk of higher prices for compliance; or

3) if higher targets are the lowest reasonable cost option for customers, considering risk; or

4) if technological advances can be cost effectively captured in a manner that justifies increased targets.

4. RCW 19.405.060(1)(c) allows the Commission to periodically adjust or expedite timelines when considering a utility's CEIP or interim targets. A common Commission practice is to respond to a motion to adjust timelines from any party with standing in a proceeding at any time or after hearing a compliance item at an open meeting.

a. What criteria should the Commission take into account in making changes to timelines?

The Commission should take into account:

1) the actual and projected costs and risk for: renewable resources by specific type, demand response measures, distributed generation, energy efficiency and conservation measures and whole building projects that combine multiple demand or demand and supply resource types, and non-emitting resources;

2) the likelihood the utility's plans will enable it to meet the statutory standards by the target dates;

3) or evidence presented in hearings that the interim targets are insufficient to lead to a reasonable compliance pathway for the utility.

b. ***When should the Commission consider adjusting or expediting the timeline? How should the Commission interpret the term "periodically?"***

The Commission should consider whether timelines are appropriate or should be adjusted every two years as they consider a utility IRP or IRP update.

c. ***Who bears the burden of demonstrating that adjusting or expediting the timeline can or cannot be achieved in a manner consistent with RCW 19.405.060(1)(c)(i)- (iv)?***

Each utility has the main responsibility for demonstrating that the interim clean energy targets it proposes in the CEIP are reasonable. However, if the Commission chooses to adjust the timeline for a utility's targets, the record of the proceeding in which they make this decision must show that 19.405.060(1)(c)(i)- (iv) can be met. Any party to a CEIP or other relevant proceeding should be able to provide evidence in this matter for the Commission to consider.

5. What level of additional detail, if any, should the specific CEIP targets include beyond the statutory language?

a. ***For energy efficiency, the target required by the Energy Independence Act, RCW 19.285.040(1)(a), follows methods consistent with those of the Pacific Northwest Power and Conservation Council and only considers first year savings. Should the energy efficiency target in the CEIP be based on cumulative savings, savings projected over the lifetimes of measures implemented in a given program year, or capacity savings?***

First, the Coalition questions whether the assertion contained in this question is accurate – in our view, the methods of the Pacific Northwest Power and Conservation Council should not be interpreted as only considering first year savings. We would be interested in discussing with staff the underlying reason for this assertion. Furthermore, we are hopeful that is does not indicate an underlying problem with the interpretation of the Pacific Northwest Power and Conservation Council methodology in the EIA rules or process.

In answer to the second part of the above question, the energy efficiency target in the CEIP should be based on the savings projected over the lifetimes of measures and should consider BOTH overall energy savings and the value of the electricity saved at during peak times and other "capacity" savings.

Considering only first-year savings tends to lead to selecting more short or shorter-term savings, rather than longer-lived, transformative energy savings projects. Because CETA is about the long-term transformation of the electric system, a longer-term perspective is required.

Regarding capacity, energy efficiency does not just lower overall demand, but can limit the magnitude of power ramps, diminish peak demands, extend the work life of existing infrastructure, etc., This means an efficiency measure very often has, due to inherent flexibility or simply the timing of savings, several capacity values. The Coalition is very supportive of valuing all those attributes as it will lead to more accurate valuation of energy efficiency measures and more consequently, more accurate forecasting of other resource needs.

b. ***For demand response (DR):***
i. How should the Commission develop a cost test to identify cost- effective demand response, as referenced in the Commission's draft rules under WAC 480-100-610(12)(e) (See Integrated Resource Plan Rulemaking, Docket UE-190698, Staff Discussion Draft Rules (Nov. 20, 2019))?

The Coalition is not sure it would recommend developing a "cost test" to identify cost-effective demand response. DR has time and duration values that vary depending on when it is employed, which makes it difficult to effectively develop a test that can evaluate the full value and varying applications for demand response in the context of the dynamic utility system. Cost effectiveness tests may not make much sense when applied to DR; DR needs to be measured as a flexible resource, balancing cost and performance. Nor should DR be compared to a natural gas plant, as the qualities that define a gas generator really don't apply to measures that can diminish ramps, reduce peaks, balance renewables a few times a year. The art of identifying all cost effective demand response is currently still developing in the region. This is a subject of active discussion at the Demand Response Advisory Committee of the Pacific Northwest Power and Conservation Council and also among many individual utilities in the region. The Coalition recommends establishing a basic rule about what utilities must do demonstrate that they are pursuing all cost-effective demand response pursuant to RCW 19.405.040 (6) (a) and issue policy guidance, that can be more readily updated, with more precise Commission direction on the latest methodologies and approaches that should be utilized. A workshop might be useful in discussing the recommended content of the rule and policy guidance.

ii. Should demand response potential be considered only within a utility's service territory or encompass the utility's entire balancing authority?

The Coalition has no response to this question at this time. We would like more information and clarification about the question prior to responding.

c. For renewable energy:
i. How should the utility calculate its target? Should it be a glide path to 2030, glide path to 2045, or both?

RCW 19.405 040(1)(a) states that a utility, to be in compliance with the clean energy standard by 2030, must FIRST "*(i) Pursue all cost-effective, reliable, and feasible conservation and efficiency resources to reduce or manage retail electric load, using the methodology established in RCW **19.285.040**, if applicable; and* SECOND*, (ii) use electricity from renewable resources and non-emitting electric generation in an amount equal to one hundred percent of the utility's retail electric loads over each multiyear compliance period. An electric utility must achieve compliance with this standard for the following compliance periods: January 1, 2030, through December 31, 2033; January 1, 2034, through December 31, 2037; January 1, 2038, through December 31, 2041; and January 1, 2042, through December 31, 2044."* (emphasis added). Alternative compliance options may satisfy **only up to 20%** of that 100% target only until 2045. (emphasis added)

Further, RCW 19.405.040 (6) (a) states that "*In meeting the standard under subsection (1) of this section… In making new investments, an electric utility must, to the maximum extent feasible:*

(i) Achieve the targets at the lowest reasonable cost, considering risk;
(ii) Consider acquisition of existing renewable resources; and
(iii) In the acquisition of new resources constructed after the effective date of this section, rely on renewable resources and energy storage…"

Therefore, a utility's interim clean energy targets should be scaled first to the 100% target in 2030, along with plans to employ alternative compliance options, if any are needed and, second, to the final 100% target in 2045. All interim clean energy standard targets should indicate how many MWhs will be delivered by renewable resources or non-emitting resources and how much alternative compliance will be relied upon. Additionally, the intent of RCW 19.405.040 is to ensure that existing renewable resources and new renewable resources and storage are prioritized over any other non-emitting generation resources. Consequently, it is important not only to set targets for renewable resources, but also to ensure that the utility is demonstrating how the targets that it sets for renewable resources conforms to the resource priority in portion of CETA.

ii. How should the utility consider and account for the Energy Independence Act renewable targets, as referenced in RCW 19.285.040, and non-emitting resources, as referenced in RCW 19.405.040(1)(a)(ii), when calculating the utility's renewable target under CETA?

A qualifying utility must still meet the EIA's ongoing target of 15% bundled non-hydro renewables or unbundled RECs from non-hydro renewables. Bundled EIA resources count toward the clean energy standard target requirements in CETA. Unbundled renewables used for compliance with EIA can also be used, per RCW 19.405.040(1)(b)(ii)(A), towards the CETA clean energy standard targets until 2045 in the form of alternative compliance options. Furthermore, if a utilities' non-EIA compliant resources account for more than 85% of load, then the amount of EIA eligible renewables required to meet the EIA targets is reduced, per 19.285.040(2)(m), to only be the amount necessary to meet the difference between the CETA eligible RE and NE and 100% of the load. It will be important to report EIA eligible resources distinctly in CETA reporting, to track the relationship between the two requirements.

6. Should the CEIP contain time ranges for the acquisition of capacity resources, or deadlines for acquisition?

Given that there may be unanticipated delays in acquisitions or contract fulfillment, it seems allowing time ranges within each compliance period for the procurement of capacity resources would be more appropriate. Additionally, due to other factors, including those outside of utility control such as changes in the economy, and those within utility control, such as exceeding conservation targets, needs for capacity resources will undoubtedly not match predictions accurately. Consequently, time ranges allow for more flexibility to adapt to ongoing changes.

Public Process

7. What guidance (content and form) should the Commission provide to ensure utilities employ robust, equitable, and inclusive public involvement **in drafting CEIPs*****?***

As we commented on UE 190698, we urge that all current public process be broadened from "inform/consult/"advise" approach to one that requires "involvement/collaboration" of stakeholders and the public. The purpose of public involvement should go beyond utilities simply presenting information to utilities intentionally sharing transparent analyses that incorporate public feedback.

Given the importance of public involvement and input in CETA, the rules should provide additional guidance to utilities for minimum requirements regarding public and stakeholder involvement in the all of the following: IRP development stage, the formal IRP process at the UTC, the CEIP development stage and the formal CEIP process at the UTC.

The International Association for Public Participation offers guidelines for such processes. https://c.ymcdn.com/sites/www.iap2.org/resource/resmgr/foundations_course/IAP2_P2_Spectrum_FINAL.pdf

Additionally, in the event that the Commission determines that the CEIP should be an adjudicative proceeding, it will be important to include public hearing and public comment opportunities (such as in a rate case) to ensure opportunities for participation from stakeholders not fully participating in the adjudicative process.

8. Given the need for utilities to integrate their integrated resource plan (IRP), clean energy action plan (CEAP), and CEIP, what procedural outline should utilities' public involvement follow and what components (e.g., advisory groups, workshops, comment periods, etc.) should be included? How should a CEIP public engagement and public

involvement process emulate or differ from the proposed rules in the IRP rulemaking (See Integrated Resource Plan Rulemaking, Docket UE-190698, Staff Discussion Draft Rules at 17 (Nov. 20, 2019)) or the conservation planning process in WAC 480-109-110 and WAC 480-109-120? Please describe in detail.

As we have commented on UE-190698, the IRP development stage should be about 15 months. At this early stage, the utility should be required to have an IRP Advisory Group that is actively engaged, from whom the utility solicits input and involves in decision-making throughout IRP development. Rules should clearly state expectations for how the IRPAG is selected; how information will be shared; how issues will be raised and by whom; how public input is solicited and incorporated; how rejected ideas will be documented and stored; how data and methodologies will be acquired, shared and updated, etc. These requirements should call for a more active, involved role than currently provided to members of any IRPAG.

There should be adequate time after the filing of the draft IRP to allow full vetting and examination by UTC staff and stakeholders, including requests for additional data sources, model runs, alternate methodology, changes of assumptions, etc. The comment period should allow the submission of written comments and a public hearing. The rules should also specify the Commission may make determinations to require additional hearings, workshops or other informational reviews, and under what circumstances.

Similarly, there should be a separate hearing on the final IRP, probably two weeks or so after the final IRP is filed. This hearing would provide stakeholders and the public a chance to comment on how well the utility incorporated feedback throughout the process, either via written or spoken comments or both. The utility or UTC staff should summarize stakeholder and public input as the process moves along, so a clear history of input and issues is available to the Commissioners to help inform their decision-making around the CEIP.

Due to the requirement for the Commission to approve or disapprove the CEIP, the CEIP process will likely need to be more formal than in an IRP process. At this stage, the utility is proposing exactly what steps it will take over the next four years towards achieving the clean energy standard targets; that plan must be approved, disapproved or approved with amendments by the Commission. Therefore, the CEIP should be subject to hearing and adjudication, which allows intervening parties to discover data, require scenario runs with different assumptions, and other types of discovery. Also similar to a rate case, to ensure adequate public participation, there should be a requirement for public hearings and a public comment period to obtain input from utility customers and other interested stakeholders not directly intervening in the adjudicative proceeding.

9. Would a requirement for a utility to file a draft CEIP for public input be useful or problematic if the plan were to be litigated? Please explain why or why not.

We have previously recommended the draft CEIP should be filed one month after IRP acknowledgement, with a three-month discovery and comment period, followed by the filing of a final CEIP for Commission action. These comments contemplated a process more similar to an IRP, rather than an adjudicative proceeding. It may be that an adjudicative proceeding makes more sense for the CEIP process. However, we see no reason why the adjudicative proceeding could not adopt the draft/final process, where rather than response comments, the utility has the opportunity to incorporate testimony by the parties into the final plan and present that for another round of comment, followed by a decision by the Commission. It is far better to provide a specific process to have issues raised and resolved by interested stakeholders and the utility prior to a Commission decision. This process would hopefully lead to an improved, collaborative approach while at the same time building a robust record to support the ultimate Commission decision.

Demonstration of Compliance with RCW 19.405.030, 040, and 050.

10. The Commission uses a planning and reporting cycle for conservation under the Energy Independence Act described in WAC 480-109-120. Should Commission rules similarly describe the level and frequency of reporting for demonstrating compliance with RCW 19.405.030, 040, and 050?

Yes. The Commission should adopt rules that outline requirements for compliance reporting with RCW 19.405.030, 040, and 050.

11. Regarding the frequency of filings:

a. Should utilities regularly file reports on their progress toward meeting compliance metrics?

Yes, utilities should file either annual or biannual compliance reports beginning in 2022. Concise progress reports filed between 2022 and 2030 serve as an early warning system if progress towards achieving the standards slips. It will be easier to ensure that utilities are on track for 2030 compliance if they are reporting regularly leading up to that compliance date. Waiting to learn that a utility is behind in its compliance until 2030 could mean extreme and costly measures must be taken in order for a utility to comply.

b. Does or should the frequency of the filings depend on the existence of a rate plan?

If a future rate plan is linked to reporting on broadly developed and supported performance metrics for a utility, it is possible that the compliance metrics needed for CETA could be combined with the rate plan performance metrics. It is unclear at this time how this might impact the frequency of either filings. Please see our response to questions 26 and 27.

12. How must a utility demonstrate to the Commission that the utility has eliminated coal-fired resources from its allocation of electricity beginning in 2026, as required in RCW 19.405.030?

Each utility should attest that coal is out of their Washington customers' bills. Additionally, each utility's fuel mix report should demonstrate the precise resources being used to serve Washington load and those fuel mix reports should be backed up with confirmation of resource source from suppliers, generation data for utility owned resources, etc. The fuel mix reports should confirm that no coal-fired resources were utilized to serve Washington customers after December 31, 2025. Fuel mix reports for a multistate utility must include the same level of detail regarding generation used to serve Washington customers as other in-state utilities. In other words, service by a utility to other states should not serve as a means to obscure or fail to report the precise resources used to serve WA customers.

13. If the Commission has four years of investment information from a utility when approving its CEIP:

a. ***How often should the Commission require the utility to update the investment plans to reflect changing information?***

   The utility should be required to update the investment plan every two years, to coincide with the development of the two-year IRP reports or updates; if there are no changes, that will be simple to report. If there are changes, then at minimum, the utility must include data sources, methodologies, calculations and assumptions that explain and support those changes.

b. ***May the updates be informational filings, or should they be formal filings subject to Commission approval?***

   If the investment plans are part of an approved CEIP, then the Commission will need to formally approve the changes. The filings should be posted to the appropriate docket and all parties notified and provided an opportunity to submit comments.

Deferral of Major Projects under RCW 80.28.410

The Coalition has no comments on this section (Questions 14 and 15) at this time, other than to recommend that it might be an appropriate topic for a workshop.

Compliance, Enforcement, and Penalties

16. RCW 19.405.090 provides that upon its own motion or at the request of the utility, and after a hearing, the Commission may issue an order relieving the utility of its administrative penalty obligation, if certain conditions are met. Does the Commission need to provide more

guidance on the application of penalties and waivers of penalties in rule? If yes, please describe what additional guidance should the Commission provide.

The Coalition does not believe that it is advisable for the Commission to take up rulemaking on this section at this time. 19.405.090(3)(a) allows such relief due to reliability or resource adequacy concerns, or due to unforeseen circumstances that prevent the utility from complying with the standard. This will not become necessary until 2030; our concern is any guidance provided now will be outdated or not useful a decade from now. The Commission will first have to define "prudent utility practices" and define what "compromise the power quality or integrity of a utility's system" would require at 19.5405.090(3)(a)(i) at that time, with the then current technology and updated practices.

Equitable Distribution of Benefits

17. RCW 19.405.040(8) states:
In complying with this section, an electric utility must, consistent with the requirements of RCW 19.280.030 and 19.405.140, ensure that all customers are benefiting from the transition to clean energy: Through the equitable distribution of energy and non-energy benefits and reduction of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits and reduction of costs and risks; and energy security and resiliency.

- ***a. Please provide a list of costs and benefits (e.g., public health, pollution) that the Commission should consider when determining a utility's compliance with RCW 19.405.040(8).***

  The following chart illustrates some items the Commission should consider when determining compliance with RCW 19.405.040 (8). Many of the examples apply to multiple CETA compliance elements.

CETA compliance element	**Items for Consideration**
Energy benefits	• Access to programs to reduce energy use such as weatherization • Participation/ownership in services such as DG, storage and DR projects, NEM programs, microgrids, transportation electrification infrastructure and investments
Non-energy benefits	• Access to energy efficiency programs
Reduction of burden to vulnerable populations and high impact	• Energy burden • Access to bill assistance

communities	• Access to energy efficiency programs
Public health benefits	• Burdens from pollution or other health and financial impacts of facility siting caused by generating resources or other utility owned/contracted resources • Impact from Health and Safety programs, including programs to prevent wildfires
Environmental benefits	• Served by clean resources • Access to energy efficiency programs
Reduction of cost and risk	• Access to energy efficiency programs • Participation/ownership in distributed generation, storage, NEM programs
Energy security	• Access to consistent service: Shut-offs, late payment fees/frequency, security deposits, arrearages, wildfire prevention strategies • Elderly and handicapped assistance services • Impact from Health and Safety programs, including programs to prevent wildfires
Resiliency	• Participation/ownership in distributed generation, storage, microgrids

b. ***Please provide a list of which geographic areas, populations, customer demographics, or other factors the Commission should consider when determining a utility's compliance with RCW 19.405.040(8).***

The utility should consider all available sources of information regarding customers in that utility's entire service area. An advisory group should be established to help the utility determine significant customer demographics, identify valid sources of data and information, and to identify gaps in information.

For sources, at minimum, the utilities should begin with Census tract or, if available, the more granular Census block data. The output from the Cumulative Impact Assessment will eventually be available and should be utilized.

As for customer demographics, the examples of demographics to consider include: relevant household data such as race, ownership vs renting/cohousing, housing type and housing value, (which can be estimated by the county assessor or from real estate analysts or reports), income/energy burden and number of occupants in a housing unit, in addition to disability and dependence on electric medical equipment.

18. In the Commission's IRP rulemaking in Docket UE-190698, many stakeholders commented that the Commission should determine compliance with RCW 19.405.040(8) as part of the CEIP process. If the Commission were to do so, what types of guidance on RCW 19.405.040(8) compliance should the Commission provide in its CEIP rules? If the Commission were to provide guidance on RCW 19.405.040(8) compliance in a form other than rules (e.g., an interpretive and policy statement), what type of guidance should the Commission provide? Please be as specific as possible in your responses.

RCW 19.405.040(8) directs the utilities to ensure that all customers benefit from utility actions related to the clean energy standard, and focuses on low-income and vulnerable communities. Because this is a legal requirement, the Commission should establish by rule the primary means by which the utility compliance with this requirement will be assessed. At a minimum, rules should specify that utilities are required to establish specific metrics in order to measure and demonstrate compliance with this subsection. Additionally, the rules should specify that the metrics be determined through a participatory process, with considerable consultation with utility customers, stakeholders and, in particular, highly impacted and vulnerable communities within the utilities service area. Metrics should be proposed and approved as a part of the CEIP. Rules should specify regular reporting on the metrics.

In order to ensure that metric development is participatory in nature, comprehensive and relatively consistent across utilities, in addition to the establishment of rules, the Commission should also issue policy guidance to utilities on the subject of equity metric development.

19. Should a utility's demonstration of compliance with the requirements in RCW 19.405.040(8) include qualitative data, quantitative data, or both? Please explain your response. If you recommend qualitative data, which of the following approaches for approximating hard-to-quantify impacts are most appropriate: (a) service territory-specific studies; (b) studies from other service territories; (c) proxies; (d) alternative

thresholds; or (e) or another approach? Does your response depend on a particular factual scenario? If so, please describe the scenario and explain why the approach you recommend is best suited for that scenario.

A utility's demonstration of compliance with RCW 19.405.040 (8) should include both qualitative and quantitative data. As the Commission considers guidance to utilities regarding the establishment of metrics, it will be important to consider that for the first years, there will probably be gaps in the data available, or only sample data available, so the utilities will have to augment their analyses with data from a number of sources. In this instance, qualitative data can be useful in indicating where data gaps exist and will help further develop metrics and metric measurements over time.

Each utility should strive to use data from studies that are the same or close to the service territory, such as the census tracts or by zip codes, specifically citing the data source, which might include UW's Self-sufficiency study, FERC form 1 reports or EIA reports. Studies from other service territories can be useful to help metric development and understand potential source data; however, the use of data from other service territories or the use of proxies should be avoided because the goal is to understand the distribution of benefits to the utility's own customer base.

20. Please provide any existing data sources or methodologies of which you are aware for quantifying non-energy costs and benefits, and other equity-related impacts.

There are numerous data sources, methodologies and sources of information for identifying, quantifying, measuring and evaluating non-energy costs and benefits and other equity-related impacts. Here is a sample of some resources the NW Energy Coalition has found particularly useful:

> *Public Health Benefits per kWh of Energy Efficiency and Renewable Energy in the United States: A Technical Report.* Environmental Protection Agency. July 2019. https://www.epa.gov/sites/production/files/2019-07/documents/bpk-report-final-508.pdf
>
> Bureau of the Census.
>
> Washington Department of Health, Cumulative impact assessment, Pending
>
> California Docket 18-IEPR-08, Energy Equity Indicators Tracking Progress. http://www.energy.ca.gov/renewables/tracking_progress/
>
> Haas Institute Equity Indices Research: https://haasinstitute.berkeley.edu/equity-indices-research
>
> *Ten Human Rights Priorities for the Power and Utilities Sector*. Business for Social Responsibility. https://www.bsr.org/en/our-insights/primers/10-human-rights-priorities-power-and-utilities-sector

FERC Form 1

University of Washington's Self Sufficiency Standards reports.
http://www.selfsufficiencystandard.org/washington

Toward Standardized Equity Measurement in the Clean Energy Industry. Marti Frank, Michael Colgrove, Carlos Martin, Emily Levin, Elizabeth Palchak, Robert Stephenson. September 1, 2019.

Research Strategy for Valuation of Comfort, Health, Noise Reduction, & Safety Non-Energy Impacts. Bonneville Power Administration. March 13, 2017.

21. How should the Commission interpret RCW 19.405.060(1)(c)(iii)? How are the requirements in that statute different than the requirements in RCW 19.405.040(8)?

The intent was to ensure the same considerations for all customers in all aspects of statute implementation. RCW 19.405.040 (8) is the broad application of these requirements. At 19.405.060(1)(c), the statute underlines that the Commission may "adjust or expedite timelines" for meeting standards, as long as that can be done in a way that maintains reliability, ensures the targets are still met at lowest reasonable cost and complies with the equity provisions of 19.405.040(8). That is achieved here by repeating the language that all customers must benefit "from the clean energy transition, through the equitable distribution of energy and non-energy benefits and the reduction of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits and reduction of costs and risks; and energy security and resiliency". As an example, adjusting timelines or expediting timelines should not lead to increasing the energy burden, any more than any other clean energy transition decision undertaken to comply with the standards.

The Commission should interpret both sections of the law to be consistent with one another.

Incremental Cost of Compliance

22. RCW 19.405.060(3) requires an electric investor-owned utility to use its weather-adjusted sales revenue to customers as reported in its most recent Commission basis report (CBR) as part of its incremental cost calculation. Each investor-owned utility is different in how it reports its weather-adjusted sales revenues and adjusts its sales for "weather."

a. Should the Commission standardize its CBR rules to be able to effectively implement the incremental cost calculation requirements in RCW 19.405.060(3)? If so, please describe how the Commission should revise those rules.

Yes, the Commission basis report should be calculated the same by all the IOUs and reported in a consistent format. For example, utilities should all be using a timeframe of twenty-year average (or potentially even a 10 or 15 year average) to calculate "normal weather" for adjustment purposes. It would be good to review how each utility is currently calculating its weather-adjusted sales revenue in its most recent Commission basis report and derive a methodology that is updated and consistent to arrive at rule language. It is likely that this will require amendment of 480-100-257(2)(c) (Commission basis report) to specify how weather adjustments are applied to sales revenue. It also seems advisable to ensure that the reporting in the FERC Form 1 is utilized in the Commission basis report in the same manner, so that fair comparisons between utilities can be made.

b. Can the Commission allow each utility to use a different weather normalization method and still create a consistent methodology for calculating incremental cost?

The Coalition does not see a need for utilities to use different weather normalization methods.

23. RCW 19.405.060(3)(a) states that an electric investor-owned utility complies with its Clean Energy Implementation Plan if, over a four-year compliance period, the utility's average incremental cost to comply with RCW 19.405.040 and 19.405.050 increases by two percent over the utility's weather-adjusted sales revenue.

c. If a utility relies on the incremental cost compliance option as detailed in RCW 19.405.060(3)(a), when should the Commission determine whether the utility has achieved the incremental cost threshold for compliance? For example, should the Commission determine the utility's compliance based on a forecast, at the time the utility files its Clean Energy Implementation Plan, based on actual data at the conclusion of the four-year period or through interim reporting, or a combination of these options?

The Commission should determine that the utility has achieved the incremental cost threshold for compliance at the end of the compliance period based on actual data. A number of important variables could change over a compliance period, substantially changing costs, such as high or low water years, population decreases or increases, or technological breakthroughs leading to cost reductions in generation, storage or efficiency costs.

Obviously, a utility will be monitoring those costs and revenue closely, so interim reports should be able to confirm or warn if projections are off track. Responsible planning, neither too cautious nor too optimistic, should be able to forecast costs, as they do now. Utility forecasting, and Commission monitoring of that forecasting, will be important to ensure compliance stays on track. However, it is only the final reporting of actual costs that will be able to confirm if the cap was, in reality, met.

d. ***If the Commission allows a utility to forecast its reliance on the incremental cost of compliance option, and the utility's actual incremental costs increase more or less than two percent averaged over the four-year period, would a true-up mechanism be allowed and necessary to reconcile the differences between the actual and the forecasted incremental cost?***

One drawback to relying too heavily on cost cap forecasts is the high likelihood that these forecasts will be wrong. Projections might forecast higher than actual costs, which could lead the utility to trim back some of the necessary compliance actions, in turn slowing progress towards reaching the standards or requiring more effort and expenses in subsequent years than would have been necessary.

If the Commission decides to allow a utility to forecast its reliance on the incremental cost of compliance option, then some true-up mechanism would be unavoidable. We would be concerned that compliance costs would be conservatively estimated on the high side, similar to how projected 937 conservation targets have been projected, where all CPA forecasts to date have been lower than actual achievement, since the utilities forecast with an abundance of caution.

24. When using the incremental cost compliance option, RCW 19.405.060(3)(a) requires all of a utility's costs to be directly attributable to the actions necessary to comply with RCW 19.405.040 and RCW 19.405.050. How should the Commission require a utility to demonstrate that such actions were "directly attributed and necessary" for the utility to take only to comply with CETA?

In the IRP and the CEAP, the utility must address a business as usual (BAU) option, with the social cost of carbon applied to that BAU. The BAU may well contain measures that help the utility obtain compliance with sections 19.405.030-.050, but would have been undertaken by the utility in the absence of CETA for other purposes (e.g. lowest reasonable cost resource acquisition), such as conservation programs, utility scale RE acquisitions, or storage projects. Only actions directly attributable to meeting the clean energy standard in sections 19.405.030, .040, and .050 of CETA that are not actions within the reasonable scope of the BAU scenario can be counted toward the incremental cost. These scenarios and calculations must be detailed in the CEIP to a granular enough level that anyone reading the report can tell which actions and resources are being counted toward the incremental cost of compliance.

25. RCW 19.405.060(3)(b) states that if a utility relies on subsection (a) (incremental cost as a basis of compliance), the utility must demonstrate that it has "maximized investments in renewable resources and non-emitting electric generation prior to using alternative compliance options." In what type of proceeding should the Commission require a utility to demonstrate that it has maximized investments in renewable resources and non-emitting electric generation? What documentation should the Commission require the utility to provide?

RCW 19.405.060 (3) (b) is intended to ensure that before applying the cost cap, utilities acquire resources, rather than investing in alternative compliance options. Specific resource acquisitions to meet the clean energy standard, along with any use of alternative compliance mechanisms, and the cost of each selection, will need to be provided by the utilities in compliance reporting. The Commission must require compliance reporting by utilities that includes this information. We recommend such reporting on an annual or biannual basis.

Cost information within the CEIP

Conservation plans include an element describing program budgets and cost recovery approaches for different resources. (See WAC 480-109-120 and 130.) As an example, a utility must recover transmission and distribution investments through a general rate case, while the utility may recover program costs through a conservation tariff rider. Further, changes to RCW 80.04.250 allow the Commission to provide for rate changes up to 48-months after the initial rate effective date. Finally, the Commission must approve a utility's CEIP, in the context of which the Commission may approve new cost-recovery approaches.

26. How should the utility address investment planning and cost recovery in its CEIP? How could a utility's CEIP be used to set rates prospectively? Would using a CEIP to set rates prospectively be in the public interest? Please explain your answer.

See below combined response to questions 26 and 27.

27. Which elements of a CEIP should a utility recover through general rate cases? Which elements of a CEIP are appropriate for a cost recovery mechanism?

With the implementation of CETA, Washington State is transforming the electric sector to 100% clean electricity and incorporating a more deliberate perspective of ensuring equitable benefits from this transition, and will need the regulatory tools to assist with this transition. Utility cost recovery is a key element that should shift with the implementation of CETA. In particular, it will be easier to achieve the public interest objectives of equitable distribution of benefits and reduction of barriers, long-term and short-term public health, economic, and environmental benefits and the reduction of costs and risks, and energy security and resiliency if we link those objectives to utility performance and cost recovery.

Performance and incentive-based regulation (PBR) is an approach that seeks reforms to traditional cost of service regulation to recognize the changes occurring in the utility sector. Rapid advances in technology, increasing customer control over usage and, increasingly, their own generation, and other trends necessitate changes to traditional ratemaking approaches that are based upon capital intensive, large power generating stations. Indeed, RCW 19.405.010 (5) expressly declares legislative intent to move toward performance based ratemaking and other flexible regulatory mechanisms.

Common elements of PBR include multiyear rate plans (MYRP) of at least 3- 5 years; an attrition relief mechanism (ARM) (sometimes called an attrition adjustment mechanism); earnings sharing mechanisms; and performance incentives mechanisms.

All of these elements are important, however, of particular relevance to these comments are performance incentive mechanisms (PIMs), which provide a method to integrate the evaluation of utility performance on important public interest objectives. PIMs provide for the adoption of specific performance metrics, targets, or incentives to affect utility performance that represents the interests of its state policy, interest groups, and customers. These mechanisms can include increments or decrements to revenue or earnings. PIMs are a commonly used tool for traditional outcomes like safety, reliability and energy efficiency. In recent years, a growing number of states have begun pursuing PIMs for more emergent outcomes like: customer satisfaction, peak demand reduction, greenhouse gas emissions reductions, distributed energy resource (DER) interconnection experience, DER utilization, among other things. We recommend integrating performance incentives with the CEIP, linked to cost recovery, for all utilities.

The development of the CEIP provides an opportunity to link the elements of performance-based ratemaking into the regulatory construct in Washington. CEIPs can identify performance incentive mechanisms and metrics, link those to utility performance and reporting, and align with multiyear rate plans and other tools for cost recovery.

Specifically, the Coalition recommends initiating performance incentives linked to metrics determined in the CEIP and establishing multiyear rate plans for each utility that include:

(a) A mechanism to adjust revenues in response to cost pressures over the rate period (e.g., incorporation of a positive x-factor and/or stretch factor to motivate cost savings);
(b) An earnings sharing mechanism; and
(c) Performance incentives and/or penalties linked to public interest goals outlined in statute.

Each utility currently uses a number of cost recovery mechanisms and other ratemaking tools and an effort to map those elements currently utilized and how they will relate to the changes under CETA will be important to begin the conversation in an informed manner. This is likely another topic that would be appropriate for a workshop. In fact the questions related to deferrals (questions 14 and 15) seem related primarily to cost recovery and potentially could be combined with these questions in a workshop.

28. Should the Commission require a utility to provide in its CEIP (a) information on program budgets related to incremental programs for compliance with CETA; (b) descriptions of, and details about, capital budgeting for all investment; or (c) both?

The Commission should require both. That information will be necessary to evaluate the cost cap threshold. The information should include, at minimum, the actual costs and a clear narrative that explains the proposal, the decision process and all calculations and assumptions.

Respectfully submitted,

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