On September 6, 2016, the Commission issued a notice requesting stakeholder feedback on the issue of potential revisions to the Integrated Resource Planning general guidelines. The NW Energy Coalition and Renewable Northwest offer the following comments in response to the questions issued by the Commission. We include our comments below each question, as applicable.

A. General:

1. *The Commission has identified a broad scope of issues to evaluate in its inquiry. Are there other issues or topics that should be addressed? What type of schedule would best lend itself to a proceeding of this scope?*

The NW Energy Coalition and Renewable Northwest recommend addressing the following topics in addition to those specifically identified by staff.

IRP Cost and Risk Measurement
The purpose of the IRP in WAC 480-100-242 states:

> "Each electric utility regulated by the commission has the responsibility to meet its system demand with a least cost mix of energy supply resources and conservation. In furtherance of that responsibility, each electric utility must develop an integrated resource plan."

The term "least cost", which appears in the purpose, is not defined; however, WAC 480-100-238 provides the following definition for "Lowest reasonable cost" :

> (b) "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. At a minimum, this analysis must consider resource cost, market-volatility risks, demand-side resource uncertainties, resource dispatchability, resource effect on system operation, the risks imposed on ratepayers, public policies regarding resource preference adopted by Washington state or the federal government and the cost of risks associated with environmental effects including emissions of carbon dioxide.

We recommend that the purpose be clarified to refer to "lowest reasonable cost" instead of "least cost." Such a change would ensure that the planning structure accounts for existing risk, future risk, potential variability in long-term fuel costs, and regulatory costs for each potential resource. In addition, we recommend that the IRP take into account expected future policies—not just state and federal policies that have been adopted.

We also recommend review of the IRP rules to ensure each IRP incorporates appropriate treatment of fuel price risk, regulatory risk, and other factors related to resource risk.

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In addition, it can be difficult to compare one utility's analysis to another's . We would support efforts to standardize how some information is calculated and presented.

Resource Diversity and System Flexibility

Resources have been evaluated for their ability to meet specific energy and capacity needs in isolation from each other. We would urge utilities to also evaluate the impacts of combining new and existing resources (e.g., solar plus wind plus storage available to meet load during parts of the day, conserving hydro or gas for peak needs). For example, the NW Power and Conservation Council's (NWPCC) 7th Power Plan identified a metric called Associated System Capacity Contribution that measured the additional value associated with a particular resource when combined with other resources in the system. Ultimately, utilities should refine and improve upon this concept, evaluating the various resource combinations for both time and locational value.

Non-structural measures, such as rate structure changes, should also be evaluated in this manner. Properly structured Time of Use rates for residential customers, for example, might have an even larger impact on peak demand than some large commercial demand response measures.

IRPs have been very energy focused; all elements of IRP guidelines should be reviewed to ensure sufficient focus on system needs more comprehensively. Pacific Power and Portland General Electric have both recently conducted flexibility studies that might inform how that shift can be pursued. We encourage the Commission to examine how to move IRP capacity considerations from a fixation on single-hour peak coincident "firm capacity" values to overall system adequacy and flexibility.

All assumptions used to evaluate resources should be transparent and, ideally, consistently formatted by all utilities. Initiating IRP guidelines to guide this work will be critically important.

Resource Costs

While it is important to look at current options for planning, the IRPs should also incorporate estimated technology development, especially for those resources undergoing rapid innovation (solar, storage, power electronics). The speed of improvement in various technologies can have a profound impact on resource choices. Indeed, the costs and projected costs of renewable technologies can fall significantly during an IRP planning cycle. Hence, keeping renewable resource assumptions up-to-date is especially important as renewable technologies achieve parity with more traditional forms of power generation. We recommend that the Commission encourage utilities to use the most up-to-date resource costs in their IRPs. This would go beyond accurate assumptions for the present, requiring utilities to anticipate the falling costs of renewable resources by factoring in experience curves, so the potential cost of a resource at the time of acquisition can be more appropriately and accurately estimated.

Portfolio Development
The development of portfolios is a crucial step in the planning process. It would be most effective to see how various portfolios perform compared to each other under varying situations across a range of economic environments. That would give a more "apples to apples" comparison. How can a base portfolio be determined if costs are not modeled across all sets of resources?

Energy Efficiency
Energy efficiency (EE), or conservation, is the first priority resource in the PNW and should be encouraged as much as possible. In this section, we offer some thoughts on areas where current practices can be improved.

Consistency with the NWPCC Plan
The guidelines for IRP development related to energy efficiency goal-setting should be revised to explicitly reflect the updated guidance from the most recent Northwest Power and Conservation Council regional power plan per RCW 19.285.040.

Pay for Performance Programs
Conservation measurement and verification has matured to allow an opportunity to expand energy efficiency programs beyond the traditional measure-by-measure deemed savings approach. "Metered savings" approaches look at actual efficiency performance of whole buildings and offer a new approach to capturing savings that may encourage more adoption of conservation actions. Pursuing these type of pay for performance type programs may require revisions to some of our established practices for evaluating conservation potential and managing programs. IRP guidelines should be reviewed and updated to facilitate implementation of this new program approach to energy efficiency.

Non-Energy Benefits
It is also time to consider how IRPs can calculate and account for non-energy benefits from conservation measures. From a total resource cost perspective, calculations that do not include considerable health and environmental benefits are incomplete and create a bias against certain energy efficiency measures.

Estimating long-term resource availability
As with other resources, IRPs should analyze costs of future conservation using experience curves, not just trend projections. The current methodology typically results in a downward trend for energy efficiency potential in timeframes beyond about 4-5 years because our current methodology only accounts for known and available technology and does not appropriately account for technology advancement. The development of the Conservation Potential Assessment (CPA) is a critical part of the conservation element of any IRP and helps determine just how much load can be anticipated. While determining the CPA, the EE supply curve development should factor in some rate of technology change, perhaps by incorporating end use potential studies

Demand Response and Energy Efficiency

Finally, with the exploding development of Demand Response (DR) measures, it is a good time to clarify the relationship between demand response measures and efficiency. Funding for EE should be kept separate from DR and storage measures, but there are many opportunities to link installation and maintenance, and recent studies by the NWPPC have shown that EE has substantial system capacity value.

Climate Change
The continuing, accelerating changes in the environment call for further analysis from utilities on the impact climate change will have on their operations and resources. Utilities should improve modeling regarding the impacts of projected changes in in-stream flow, temperature and other factors that will, in turn, impact energy and capacity needs over time, based on the most recent science available on those topics.

The Commission should also seriously consider if utilities must include the social cost of carbon in IRP analyses. In 2014, Executive Order 14-04 required any state agency conducting a public acquisition process for buildings and vehicles to include full accounting for the external cost of greenhouse gas emissions; the number used is the federal cost of carbon with a 2.5% discount rate (for perspective, ExxonMobil reported to the Carbon Disclosure Project in 2013 a price of $60 per metric ton of emissions for internal planning purposes; Chevron and others up to $46 per ton). Utilities are consistently underestimating the future cost of carbon in their current IRPs.

Understanding the electric system contribution and responsibility to help meet the Washington state climate goals is an important issue that is not adequately addressed in the IRP. Each utility should be required to present at least one portfolio in its IRP analysis that demonstrates achieving the utility's share of Washington State's climate goals.

Commission IRP Acknowledgment and Recommendations
The final document issued by the Commission at the conclusion of an IRP review is called an "acknowledgment letter".[1] Assuming the IRP is found to be consistent with Washington rules, at the conclusion of such a letter, the Commission may include a statement that it "acknowledges that [the utility's] Integrated Resource Plan complies with WAC 480-100-238 and WAC 480-90-238".[2] However, the recommendations in the acknowledgment letter pertain to future IRPs, rather than the IRP being considered for compliance with the WAC.[3] Instead of an acknowledgment letter with recommendations for future IRPs, we recommend that the Commission consider issuing an order in which the IRP being evaluated is either acknowledged, together with any revisions and

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[1] For example, UE-141170, Puget Sound Energy 2015 IRP, 'Acknowledgment letter to Ken Johnson, regarding PSE IRP', May 9, 2016, www.utc.wa.gov/_layouts/15/CasesPublicWebsite/CaseItemList.aspx?item=documents&year=2014&docketNumber=141170

[2] UE-141170, Puget Sound Energy 2015 IRP, 'Acknowledgment letter to Ken Johnson, regarding PSE IRP', May 9, 2016, p 15

[3] Ibid.

additional requirements adopted by the Commission, or not acknowledged. Such an approach would enable the input of stakeholders and the Commission during the IRP investigation, including testimony and discovery, to potentially affect that IRP. This approach would allow for the Commission's concerns and recommendations to be addressed before the utility implemented the IRP.

ELCC

The Commission should consider if there is an opportunity to designate the Effective Load Carrying Capability (ELCC) methodology or a simplified equivalent (like PacifiCorp is using) as the required approach in Washington's IRP process for calculating a variable resource's capacity contribution or capacity credit. This would require the Commission to examine how to move IRP capacity considerations from a focus on single-hour peak coincident "firm capacity" values to overall system adequacy and flexibility, as discussed above.

The National Renewable Energy Laboratory (NREL) identified two types of capacity credit: operational and system adequacy. NREL's Michael Milligan, PhD. characterized these two types of capacity credit in a publicly available presentation that he gave to the Utility Variable-Generation Integration Group in June 2014.[4] Operational capacity value is concerned with how much capacity a variable generator will produce at a given date or time.[5] System adequacy capacity value, on the other hand, is concerned with whether there is enough installed capacity in a certain year to reliably serve load.[6] These two views of capacity value are described as "two very different questions".[7]

When presenting to the Oregon Public Utility Commission on "Methods to Model and Calculate Capacity Contributions of Variable Generation" on August 17, 2015, Dr. Milligan stated that "A generator contributes to resource adequacy if it reduces the LOLP in some or all hours or days".[8] We recommend that the Commission explore the different ways that variable generation can contribute to capacity, whether operationally or in terms of system capacity, so that variable generation's contribution to capacity can be calculated and valued appropriately in the IRP process.

B. Energy storage

1. *The Commission has already engaged in an investigation regarding energy storage technologies and their treatment in IRP documents (Docket UE-151069). The Commission is considering merging that investigation with this proceeding,*

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[4] Utility Variable-Generation Integration Group, Capacity Value of Variable Generation, June 2014, Slide 3, www.uwig.org/shortcourse2014/Session-6-Milligan.pdf

[5] Utility Variable-Generation Integration Group, Capacity Value of Variable Generation, June 2014, Slide 3, www.uwig.org/shortcourse2014/Session-6-Milligan.pdf

[6] Utility Variable-Generation Integration Group, Capacity Value of Variable Generation, June 2014, Slide 3, www.uwig.org/shortcourse2014/Session-6-Milligan.pdf.

[7] Utility Variable-Generation Integration Group, Capacity Value of Variable Generation, June 2014, Slide 3, www.uwig.org/shortcourse2014/Session-6-Milligan.pdf.

[8] Michael Milligan, Ph.D., Methods to Model and Calculate Capacity Contributions of Variable Generation, OPUC, August 17, 2015, Slide 9 (p95 of pdf). http://edocs.puc.state.or.us/efdocs/HTB/um1719htb142830.pdf

then issuing a straw proposal and soliciting one more round of comments before issuing a policy statement on the topic. Do the parties have any concerns with this approach? Is there any information relative to modeling energy storage that has not been presented in the existing docket?

To the extent that merging the storage docket with this larger rulemaking docket would delay the former, we would advise keeping the storage docket separate. If merging the storage docket into this docket can be accomplished without delaying issuance of a policy statement and/or storage-related rules, then we would support merging the two. Regardless of whether the two investigations are merged, it would be worth considering how energy storage will be addressed beyond the scope of the current docket and what elements will be incorporated specifically into IRP planning.

C. Requests for proposals

1. *WAC 480-107-015 requires any utility that files an IRP identifying a generation capacity shortfall within the next three years to issue a request for proposals (RFP) within 135 days of filing its IRP. In recent IRP cycles, utilities have frequently requested waivers of this rule, generally citing the cost and complexity of the RFP process and stating that the IRP selected market purchases as the low-cost, preferred approach to meeting short-term capacity needs. Given the frequent requests for waivers of this rule, should the Commission change it? What type of changes would parties recommend to make the rule more broadly applicable and reduce the need for waiver requests?*

In evaluating rules and processes related to utility acquisition of resources, the NW Energy Coalition and Renewable Northwest are guided by the following principles:

- A fair, transparent, and competitive resource procurement process is essential to the procurement of lowest cost and lowest risk resources.
    - The procurement process must be fair and open in order for different types of resources to be able to meaningfully compete.
    - Competition minimizes costs and maximizes customer value over the long-term.
    - A fair, transparent, and competitive resource procurement process is important in ensuring a vibrant supply, which in turn, drives down costs for customers.
- We support efforts to increase competition in the procurement of resources, including energy efficiency and renewable energy.
    - Competition in resource procurement is important in ensuring that clean energy resources—and their attendant benefits—can be brought onto the system as cost-effectively as possible.
- The current utility business model provides an economic incentive to utilities to favor ownership of generation resources.
- In light of the economic incentives afforded by the regulatory compact for utilities to favor utility ownership of resources, conscious efforts are needed to ensure

fairness, transparency, and meaningful competition in resource procurement processes.[9]
- At the same time, it is important to ensure that utilities remain financially viable.

With these principles in mind, we recommend that the Commission revise its rules on competitive solicitation to promote fairness, transparency, and competition in the acquisition of resources. We recommend revising the criteria for issuing a competitive solicitation so that RFPs are not solely required when an IRP identifies a generation capacity shortfall, but could also be triggered by other resource needs. We also recommend adopting criteria regarding how the RFPs should be conducted in order to promote fairness, transparency, and competition. In addition, we recommend adopting criteria identifying the conditions under which a utility may request a waiver of the requirement to issue an RFP.

We also note that the utility industry is in a time of some transition, moving from systems dominated by large power plants to a more diverse system made up of smaller and dispersed resources – energy efficiency, demand response, distributed generation, etc. This shift will necessitate changes to our traditional planning and procurement processes. We recommend that the Commission take a broader view of this question to examine what the appropriate future relationship between planning and procurement will be and what types of IRP guidelines will facilitate a structure that is flexible enough to ensure reliable resource choices, structured enough to meet the utilities' needs, and transparent enough to ensure substantial involvement by stakeholder groups. The overall system, in moving from a limited firm capacity approach toward a broader flexible resource adequacy construct, may need to evolve to one that is more reactive to changing circumstances.

Finally, we recommend that the Commission consider conducting workshops to discuss potential changes to the regulatory compact in Washington that could address the issue of the economic incentives in the utility business model that favor utility ownership of generation resources. Given the various changes occurring in the utility industry, it is worth exploring a more sustainable approach to the utility business model that promotes competition and confidence in the marketplace, while keeping utilities financially viable. We understand that there are many issues on the list for this docket that may be more time-sensitive and easier to tackle. We nonetheless recommend that this conversation be somewhere on the list for this docket.

> *Utilities state that the RFP process is time-consuming and complex, and does not lend itself to a biennial cycle. Are there alternative means of meeting the rule's requirement? Would narrowly crafted solicitations that are tailored to the specific resource needs identified in the IRP be an effective way of reducing administrative burden and costs, while still encouraging bidders to provide the utility with a range of resource options?*

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[9] *See, e.g.,* Calpine, Natural Resources Defense Council, & PacifiCorp, "A Joint Proposal to State Utility Regulators: Defining Electricity-Resource Portfolio Management Responsibilities" at 3 (July 2003).

2. *In considering the waiver requests to this rule, Commission staff and utilities have been at odds whether the IRP actually identified a resource shortfall in the following three years. Staff has generally held that if the IRP model relies on market purchases for capacity needs, then the utility is short on capacity; utilities have generally held that if the model selected market purchases, then the resource need has been cost-effectively met. Is there a potential compromise on this issue? Could improved modeling of market risk in the IRP increase confidence in the model's determination? How might market risk be modeled?*

We agree that market risk is typically undervalued in IRP's and would support examining methods to improve the modeling of both short and long-term market risk.

3. *Conservation is currently included in WAC 480-107-015. Should the commission require utilities to issue RFPs for conservation measures and programs on a regular basis? If so, should RFPs be issued in conjunction with the IRP cycle or the biennial conservation planning cycle described in WAC 480-109-120?*

Conservation RFPs should be done on a periodic, regular basis to test the market to ensure that the utility is capturing all available, cost effective energy efficiency. Furthermore, conservation IRPs should not be limited by proscriptive approaches that call for particular measures or technologies. A regulated utility has undue leverage in the market; limiting any RFPs to certain measures reduces competition and may ignore effective new technologies or leave innovative solutions on the table.

Conservation RFP should describe the characteristics of the resource (including timing or location if appropriate) that is needed, but not the measures that will be accepted. There may be a need for sectoral-specific RFPs to balance the overall conservation portfolio (e.g., low income/HTR, specific Commercial & Industrial sector requests, etc.)

This open-ended approach to RFPs should also be adopted for behavioral efficiency savings and demand response. We cannot assume the measures that exist and are available today are the only measures that will be available going forward.

D. Avoided costs

1. *Avoided costs are used by utilities in multiple applications. They are used for determining rates for qualifying facilities in compliance with the Public Utility Regulatory Policy Act (PURPA), they are used for identifying cost-effective conservation measures, and they are used in determining the incremental cost of resources used for complying with the state's renewable portfolio standard. Despite their ubiquitous use, however, avoided costs can be difficult, if not impossible, to identify in current utility planning. Would it be feasible and beneficial for the utilities to transparently report their avoided costs in the IRP document? What obstacles exist that would complicate such a report? Would it be possible to create a generic avoided cost calculator that could be used to generate avoided costs for various applications? Should the included elements of*

avoided costs be different for different applications? Is the avoided cost methodology different for natural gas distribution utilities?

Overall, the notion of a single resource type representing avoided cost could be replaced by something that is more of a net system cost. For BPA's full requirements utilities, this is already the case – the avoided cost is effectively the market price for Tier 2 resources.

It is important that avoided cost calculations be transparent and readily understood by participants in utility IRP processes and other utility planning. Utilities should have to report avoided cost with detailed calculations and assumptions. There should also be consistency in how avoided costs are calculated from utility to utility. Avoided costs should look at energy *and* capacity needs. Due to differing legal requirements associated with different resource types, it may be necessary for the elements of avoided cost calculations to differ based on the applications, but there should be an effort to ensure consistency among avoided cost calculations within a utility and between utilities.

An avoided cost calculator is an intriguing idea, one that would need to be carefully constructed.

The timing of avoided cost calculations is also an issue the Commission should consider for review. Utilities are required to update avoided costs at least once per year, but are not limited in the number of times the calculation can be updated within a given year. Limits to the frequency of avoided cost updates would help provide greater certainty to qualifying facilities (QFs) under PURPA and could help provide greater consistency to the nature of the updates. As far as consistency, the current structure enables utilities to update avoided cost rates whenever there is a sudden decrease in natural gas prices, but does not require an update when natural gas prices increase. More certainty on the frequency of allowable updates and the conditions under which an update should occur could help encourage more consistent updating of avoided costs—both upward and downward. Thus, we encourage the Commission to adopt guidelines regarding the frequency and conditions under which utilities can update their avoided costs.

We also encourage the Commission to consider revising the minimum contract length applicable to QFs under PURPA. The majority of the costs associated with the development of renewable resources are upfront capital costs, making the contract length an important factor in the ability to finance a new project. Utilities in Washington currently offer QF contract lengths between five and ten years, depending on the conditions. However, such contract lengths make it extremely difficult to finance a renewable energy project. In our view, the contract length is one of the primary obstacles to the development of QFs in Washington. We recommend that the Commission consider adopting a 20-year contract length for QFs. Such a contract length is considered to be the minimum industry standard for financing renewable energy projects.

E. Transmission and distribution modeling

1. *The IRP rule requires utilities to conduct "an assessment of transmission system capability and reliability" and "a comparative evaluation of energy supply*

resources (including transmission and distribution) ….” How are utilities currently meeting these requirements in their IRPs? Has modeling software advanced in a way that might allow for a more detailed analysis of transmission and distribution systems?

We support more detailed distribution and transmission system analyses as part of each IRP. The Commission should consider initiating distribution resource planning (DRP) process requirements.

2. *To what degree are utilities currently planning for distribution system impacts such as electric vehicles, changes in end uses, and distributed generation? Are there opportunities for utilities to improve their modeling related to these issues without overly burdening the planning process?*

Whatever planning the utilities are doing now regarding distribution system impacts of solar, other dg, ev, etc., is generally opaque. IRPs are going to have to provide more distribution system analysis on a geographic basis, to attain maximum value for distributed generation, conservation and demand response.

3. *The Commission's rule requiring smart grid reports, 480-100-505, is scheduled to sunset this year absent an order from the Commission requiring utilities to consider filing the reports. What has the experience of utilities been in filing these reports? Would there be value in extending this requirement? Is there a way to address the Commission's desire for information on this topic through the IRP?*

We see no convincing reason why distribution resource planning and smart grid planning, including transmission planning, should not be included in the IRP process. That brings into one focus all the elements of transmission and generation and how they interact, presenting a more complete, integrated picture to customers.

4. *The natural gas IRP rule requires plans to include "an assessment of pipeline transmission capability and reliability and opportunities for additional pipeline transmission resources," but is silent on distribution system modeling. To what degree are gas utilities currently engaged in modeling their distribution system? Would it be beneficial for utilities to further engage in distribution system modeling? If so, is there commercially available software that is capable of meeting these modeling needs?*

Yes, both gas and electric planning should combine transmission, distribution and generation planning into the IRP. As an example of why this is important, in Oregon, NW Natural identified distribution system constraints in a particular area of its system and was able to attempt to increase energy efficiency in this geographic location to avoid an upgrade to the distribution system. Combining generation and T&D planning can highlight such opportunities.

5. *In recent years, other states have required or considered requiring utilities to engage in full-scale distribution system planning. What are the costs and obstacles associated with such a requirement? What are the benefits? Is detailed distribution planning feasible now, and if not, what is needed for it to become so?*

Distribution resource planning (DRP) is conducted in other states; it would make sense to examine California or Oregon's approaches to DRP. There are a handful of generally used models (e.g., CYME feeder modeling) available that could be used, instead of creating models from scratch.

F. Flexible resource modeling

1. *Current IRP models balance load and resources on an hourly basis over a 20-year period, generating more than 175,000 data points for the model to solve. Many of the new resource alternatives that utilities consider, however, operate on a sub-hourly basis and therefore generate benefits that cannot be captured in the IRP's hourly modeling. These benefits promise to increase over time as the penetration of variable generation increases and the need for flexibility from fast-moving resources grows. Prime examples of this type of resource are energy storage, reciprocating engines and the Energy Imbalance Market. How are utilities accounting for sub-hourly resources in current IRP models?*

2. *Are there readily available means of using sub-hourly IRP models? For example, if the model ran in 15-minute increments over 20 years, it would generate more than 700,000 data points – four times as many as current models. But if it ran in 15-minute increments for just 10 years, it would only double the number of data points, to about 350,000. Would it be possible to adapt current IRP models to operate in that way? Are there commercially available alternatives for sub-hourly modeling? Do utilities or other parties have experience in operating those models?*

Typically, the approach is to run a year or selected periods on a sub-hourly basis in specialized models. E3's REFLEX can do that, for example. It would require massive computing and analytic capacity to run sub-hourly models for the entire planning period.

G. Procedural improvements

1. *Should the commission clarify its treatment of confidential information in IRP and RFP dockets? If so, how?*

As data becomes ever more important in all aspects of IRP modeling and assessment, it is important to have clear guidelines that ensure as much transparency as possible. There are data sets that really do need to be protected – for example, some data covered by federal Critical Energy Infrastructure Information (CEII) provisions and some data that might be truly market sensitive. But in a regulated utility situation, as much data as possible should be available to the ratepayers and other stakeholders. We would want to see a high bar for claiming any confidentiality, including market sensitivity.

2. *Should the commission outline more specific requirements for public involvement, like identification of meeting time and location on the workplan, and the identification of the date a draft will be available for public review?*

Being specific will only be useful if the information is easily accessible and widely announced. Further, information about the IRP and the process to create it should be prominently and clearly displayed on the utility's website; any documents that result from the process, draft or final, should also be clearly and easily accessible, not buried at the end of a series of links. Both draft and final documents should be downloadable, as a whole document or by chapter or sections.

3. *How can the commission increase the transparency of IRP models? Is there a way to allow commission staff and other stakeholders to independently access company modeling software and test assumptions, without violating proprietary agreements or confidentiality, as is done with power cost models?*

4. *Are there any improvements that could be made in the IRP reporting or review process? Staff will ensure rule language is simplified and written in terminology that promotes clarity and understanding for all stakeholders. Rules that are written in Plain Talk are easier to understand and implement consistently.*

We commend and appreciate staff's commitment to making the rules clear and understandable and the process more effective and transparent.