BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1302

In the Matter of	)	
PUBLIC UTILITY COMMISSION OF OREGON,	)	FINAL COMMENTS OF EMO, NWEC & RNP
	)	11/16/2007
Staff Investigation into the Treatment of CO_2 Risk in the Integrated Resource Planning Process.	)	

I. Introduction

Ecumenical Ministries of Oregon, NW Energy Coalition and Renewable Northwest Project (the Joint Parties[1]) are very supportive of Staff's proposed Guideline 8. We would again like to note the high level of agreement among all parties in this Docket and we appreciate the willingness of both the Joint Utilities and Staff to explore new methodologies to more rigorously plan for carbon risks in an era of regulatory uncertainty.

In the following sections, we discuss each paragraph of Staff's proposed Guideline 8 before responding directly to Staff's Clarifying Comments of October 24th, 2007 regarding "upstream" emissions.

[1] The Citizens Utility Board of Oregon filed joined comments with EMO, NWEC and RNP in previous rounds of filings for this docket, but was unable to join the Joint Parties in filing this final round of comments.

II. Response to Staff's Proposed Guideline 8

<u>Paragraph 8a.</u> BASE CASE AND OTHER COMPLIANCE SCENARIOS

We strongly support the replacement of the specified range of CO_2 compliance costs in the current Guideline 8 with new direction to define a range of potential CO_2 compliance scenarios that can evolve over time to accurately reflect the current policy environment. Given the rapidly changing nature of potential CO_2 regulation, a flexible guideline that can accommodate the evolving policy environment is critical. Utilities should consistently update their compliance scenarios in each IRP cycle to reflect the full range of credible regulatory proposals at any jurisdiction that may affect the utility. We agree with Staff that utilities should develop at least two different compliance scenarios within the range of possible scenarios, in addition to the upper and lower limits of the credible range.

In Staff's Final Comments of September 26th, they write "Staff notes Joint Parties' and ODOE acceptance of an earlier Staff draft proposal of $100 (levelized 2005 dollars) per ton of CO_2" as a fixed upper range of compliance scenarios, should the Commission desire to set such a fixed limit. To clarify, we agreed that $100/ton was an acceptable value to reflect the upper range of *current* CO_2 policy proposals, based on our survey in our Opening Comments. In our Comments of September 26th, we supported the inclusion of a parenthetical mentioning the $100/ton value to "[provide] useful guidance to utilities on the *minimum* range of adders that is appropriate, given the current policy environment, *while leaving utilities the freedom to adjust this range upward if appropriate*" (emphasis added). As noted above, the policy environment is evolving rapidly, and the $100/ton value may or may not be appropriate by the next IRP cycle, let alone for future IRPs.[2] We would therefore strongly caution against setting a fixed upper range to the CO_2 compliance scenarios in the Guideline.

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[2] We note that while $100/ton may be a higher adder value than necessary to induce significant emissions reductions in the electricity sector, that level corresponds to only about $1.00/gallon of gasoline, which may not be enough to reduce transportation emissions to the needed extent. When modeling an economy-wide cap-and-trade scenario, utilities will need to take into account the marginal emissions reduction cost across all covered sectors, as emissions allowances under the cap will effectively trade at this marginal cost.

The proposed Guideline rightly recognizes that CO_2 regulatory scenarios may be in the form of a ban on certain resources – e.g. an emissions performance standard – rather than (or in addition to) a tax or cap-and-trade scenario. Such regulatory scenarios are clearly likely.

We appreciate that Staff has explicitly included direction to consider the price elasticity of demand in relation to CO_2 regulatory scenarios and their effects on energy prices by including the phrase "sales volume" in the final sentence of paragraph 8a. We will further discuss this final sentence as it relates to the issue of upstream emissions associated with fuel purchases and the resulting effect on fuel prices under possible CO_2 regulatory scenarios in our response to Staff's Clarifying Comments below.

Paragraph 8b. PREFERRED AND ALTERNATIVE PORTFOLIOS

We are indifferent to the inclusion of the first sentence of Paragraph 8b. As we noted in our Comments of September 26th, it may be redundant given existing Guidelines 1b and 1c. We do however agree with Staff that this sentence merely codifies existing utility practice, so do not find it problematic to include in Guideline 8.

We support the inclusion of end-effect considerations and the direction to modify plant lifetimes to be logically consistent with CO_2 regulatory scenarios. As noted in our Comments of September 26th, "consistent and reasonable assumptions regarding a plant's useful lifespan, especially as they relate to CO_2 regulatory scenarios, are a critical element of robust IRP analysis." CO_2 regulatory scenarios could clearly result in shorter economic lifespans for highly emitting resources, particularly pulverized coal plants, and IRP analysis should maintain logical consistency between CO_2 regulatory scenarios and assumptions about useful economic lives of both new and existing generating resources.

Paragraph 8c. TRIGGER POINT ANALYSIS

We strongly support the addition of trigger point analysis to IRP assessment of CO_2 regulatory risk. Trigger point analysis will greatly enhance the exploration of CO_2 regulatory risk and help reveal strategies to mitigate that risk.

However, we note that Staff's proposed Paragraph 8c only directs the utility to identify *one* trigger point and develop a single substitute portfolio for this trigger point scenario. It is highly likely that there is more than one "turning point" within the range of potential CO_2 regulatory costs at which different portfolios would be optimal. For example, at one CO_2 adder level, a utility may select natural gas CCCTs over pulverized coal plants to meet baseload/intermediate generation needs within the portfolio as well as more wind resources to hedge against gas price risk exposure, while at a higher CO_2 adder value, the utility may select coal IGCC plants with sequestration instead of gas CCCTs, and may need less wind resources. To get the full value out of trigger point analysis, we would therefore encourage the following changes to proposed Paragraph 8c:

> c. TRIGGER POINT ANALYSIS: The utility should identify ~~a~~ *one or more* minimum CO_2 compliance cost~~s~~ "turning point*s*" which, if anticipated now, would lead to, or "trigger" the selection of a portfolio of resources that is substantially different from the preferred portfolio. The utility should develop a substitute portfolio appropriate for ~~this~~ *each of these* trigger point scenario*s* and compare the substitute ~~portfolio's~~ *portfolios'* expected cost and risk performance*s* to the preferred portfolio – under the base case and each of the above CO_2 compliance scenarios. The utility should provide its assessment of whether a CO_2 regulatory future that is equally or more stringent than ~~the~~ *each* identified trigger point will be mandated.

Paragraph 8d. CO_2 RISK ADAPTABILITY

We support Staff's proposed Paragraph 8d and the addition of CO_2 risk adaptability analysis to IRP assessment of CO_2 regulatory risk and potential risk mitigation strategies. We believe that when coupled with trigger point analysis, CO_2 risk adaptability analysis will help utilities conduct a much more robust assessment of CO_2 regulatory risk and will help reveal the potential value of "optionality" in resource decisions.

Paragraph 8e. OREGON COMPLIANCE PORTFOLIO

Oregon energy policy is evolving rapidly to deal with concerns about climate change. Paragraph 8e appropriately offers explicit direction to utilities to develop at least one portfolio that is fully consistent with Oregon's evolving policy environment, including statewide greenhouse gas emission reduction targets.[3]

III. Response to Staff's Clarifying Comments of October 24th, 2007

First, we appreciate Staff's inclusion of upstream emissions within the proposed Guideline. However, we are perplexed by Staff's Clarifying Comments of October 24th, 2007, which seem to limit consideration of upstream emissions only to those associated with purchased electricity. As Staff writes in their Clarifying Comments:

> "What Staff had, and continues to have, in mind in its reference to upstream emissions are the emissions produced when a third party generates power that a utility obtains in the wholesale market to accommodate its own retail loads. … Staff's objective in the guideline was to make explicit that emissions produced directly by a third party in producing electricity which is then delivered to a retail utility might necessarily be recognized by the utility."

Staff cautions that the concept of upstream emissions could be taken to a "literal extreme" that would result in "an impossible encumbrance for a utility to have to track all these kinds of upstream emissions when paying a CO_2 emissions tax."

We believe there is some confusion about the concept of upstream emissions, perhaps arising from the fact that utilities may be exposed to regulatory risk associated with upstream emissions in two ways. First, under possible regulatory scenarios, utilities may be directly responsible for reducing emissions from generating facilities that serve that utility's load or provide power purchased in the market by the utility. In this case, a utility is directly responsible for upstream emissions and carries the regulatory cost of compliance directly. We believe this is the scenario that Staff is describing in their Clarifying Comments.

Utilities may be exposed to regulatory risk from upstream emissions in a second manner however. As we argued in our Comments of September 26th, "Emissions in

[3] House Bill 3543, passed by the 2007 Oregon Legislative Assembly, sets the following statewide greenhouse gas emissions reduction targets: arrest growth in emissions by 2010; reduce emissions at least 10% below 1990 levels by 2020; reduce emissions at least 75% below 1990 levels by 2050. While it is unclear how these statewide goals will be translated into regulation for Oregon utilities, it is clear that utilities will need to plan ways to reduce their overall emissions in a manner that contributes to these overall statewide emissions reduction goals, and should be planning portfolios that achieve substantial reductions in overall emissions.

upstream sectors will likely be regulated, just as emissions in the electricity sector will, and these regulations will add costs to various fuels" relative to the regulated emissions associated with that fuel's production and transportation and/or distribution. The fuel production and fuel transportation/distribution sectors – including natural gas, coal and coal gasification industries – are large sources of greenhouse gas emissions and will likely face compliance costs under future CO_2 regulation. To the extent that these compliance costs are passed on to end customers – e.g. the electricity generators and utilities – these upstream emissions pose another significant financial risk for utilities associated with future CO_2 regulation. In this manner, a utility is not *directly* responsible for the upstream emissions under the regulation, but is nonetheless *financially exposed* to regulatory risk due to upstream emissions.

Our interpretation of Staff's proposed Guideline 8 is that Paragraph 8a ably encompasses both of these forms of regulatory risk due to upstream emissions. The first form of exposure – direct responsibility for upstream emissions associated with electricity generation serving the utility's load – is encompassed by the following sentence:

> "The utility should identify whether the basis of those requirements, or "costs," would be CO_2 taxes, a ban on certain types of resources, or CO_2 caps (with or without flexibility mechanisms … *and potentially recognizing upstream emissions relating to energy purchases*)" [emphasis added].

The second form of exposure – indirect financial exposure to upstream emissions in the form of increased fuel costs – is encompassed by the next sentence in Paragraph 8a:

> "Each compliance scenario should *maintain logical consistency, to the extent practical, between CO_2 regulatory requirements and other key inputs including, but not limited to, expected interactive effects with … fuel and electricity prices."* [emphasis added].

We explored this possible confusion in correspondence with Staff that followed the filing of their Clarifying Comments. Based on that correspondence, it seems that Staff is in agreement that both forms of risk exposure to upstream emissions would be encompassed by the current proposed Guideline. In a Memorandum dated November 15th (see attached), OPUC Staff George Compton writes:

> "[I]f CO_2 emissions are taxed directly, such will show up both in the taxes paid for the utility's own emissions and in the "fuel and electricity prices" which the utilities are instructed by the Staff's guideline to tie to the various CO_2 regulatory requirements that go into their base case and other compliance scenarios. As regards a retail CO_2 cap (or cap-and-trade) environment, the guideline instructs the utility to include in its CO_2 regulatory footprint whatever upstream emissions it sees as being mandated to include by the environmental rules and regulations it anticipates or hypothecates.

Furthermore, in reference to the specific example raised in our Comments of September 13th that Avista is exploring the CO_2-intesive process of coal gasification to provide synthetic natural gas for gas generating facilities, Compton writes:

> "Under Staff's recommended Guideline 8, Avista's descriptions of its Base Case and other Compliance Scenarios would include whether or not, or to what degree and kind, Federal and State environmental regulations imposed revenue requirement burdens in the form of direct emissions taxes, fuel and electricity cost/market price increases, and regulatory cap-and-trade footprints."

This again seems to be consistent with our interpretation of the proposed Guideline.

We recommend a final Guideline 8 that directs a utility to consider, to the extent practical, their exposure to regulatory risk from upstream emissions, whether directly included in the utility's compliance obligations under a cap or tax scenario, or indirectly born by the utility as financial exposure to increased fuel or other costs. Both forms of regulatory risk present key financial risk exposures for the utility under potential CO_2 regulatory scenarios. Utilities should be explicit and logically consistent about how they address these risks in IRP analysis. Our interpretation is that the current proposed Guideline 8 adequately encompasses both forms of risk exposure and directs utilities to consider them as part of their environmental cost/risk planning.

III. Conclusions

We are strongly supportive of Staff's proposed Guideline 8, with the following clarifications or minor amendments:

- The inclusion of a specific CO_2 adder value in Staff's proposed Paragraph 8a (e.g. $100/ton) should be offered only as guidance for an appropriate upper range of CO_2 compliance scenarios reflecting *the current* policy environment, and should not constrain utilities from selecting a different upper range value as the policy environment continues to evolve.

- We believe it is highly likely that there is more than one "trigger point" within the range of potential CO_2 regulatory costs at which different portfolios would be optimal and recommend changes to Staff's proposed Paragraph 8c that direct utilities to identify one *or more* "trigger point" scenarios and develop a substitute portfolio appropriate for each of these trigger points.

- We support Staff's proposed Paragraph 8a to the extent that it encompasses both direct regulatory costs and indirect financial exposure to upstream emissions regulated under potential CO_2 regulatory scenarios. Our interpretation of Paragraph 8a is that the current proposed Guideline 8 is adequate, but we seek clarification that the Commission is in agreement on this interpretation.

Respectfully Submitted,

November 16, 2007

/s/ James Edelson	Ecumenical Ministries of Oregon
/s/ Jesse Jenkins	Renewable Northwest Project
/s/ Steve Weiss	NW Energy Coalition

ATTACHMENT A. Staff Memorandum, November 15th 2007

M E M O R A N D U M

TO:	Steve Weiss, NW Energy Associates
CC:	Jason Eisdorfer (CUB), Phillip Carver (ODOE), Jesse Jenkins (RNP), James Edelson (EMO)
FROM:	George R. Compton, Oregon PUC Staff
RE:	Steve Weiss's Questions on UM 1302 and Upstream Emissions
DATE:	November 16, 2007

I'm happy to respond to Steve's questions/examples regarding the need for Oregon electric utilities to give extensive consideration to upstream emissions. But first, some context:

Background: Fairly late in what had been largely a collaborative IRP Guideline #8 (Environmental Costs) developmental process, the Joint Parties (CUB, EMO, NWEC & RNP) introduced a new guideline element titled "UPSTREAM CO_2 EMISSIONS." The "FINAL COMMENTS" version of that element calls for the utility to "include, to the extent practicable, a value for the upstream CO_2 emissions associated with fuel purchases and their effect on fuel prices in all the portfolios it considers. Upstream sources…include…emissions associated with mining,…liquefaction, gasification…[etc]….[T]he utility should identify whether or not each CO_2 regulatory compliance scenario described above includes regulation of these upstream emissions sources."

Staff was receptive to some consideration of upstream emissions, as indicated by its inclusion of the italicized language within the first paragraph of its recommended guideline as follows: "The utility should identify whether the basis of those [environmental] requirements, or 'costs,' would be CO_2 taxes, a ban on certain types of resources, or CO_2 caps (with or without flexibility mechanisms such as trading or a safety valve, and potentially recognizing *upstream emissions relating to energy purchases* [emphasis added]). Each compliance scenario should maintain logical consistency, to the extent practicable, between the CO_2 regulatory requirements and other key inputs including, but not limited to, expected interactive effects with sales volumes and fuel and electricity prices."

On Nov. 5th and 7th, Mr. Weiss emailed Staff his concern that "In Staff's Clarifying Comments regarding 'upstream emissions,' there is no reference to dealing with the two main examples I had given in our comments." He then reminded us of the specifics of the examples (to be responded to below).

Staff continues to believe that its generic language is sufficient to capture the upstream emissions costs/risks that will be seen by the utilities in terms of their prospective revenue requirements. Again, if CO_2 emissions are taxed directly, such will show up both in the taxes paid for the utility's own emissions and in the "fuel and electricity prices" which the utilities are instructed by the Staff's guideline to tie to the various CO_2 regulatory requirements that go into their base case and other compliance scenarios. As regards a retail CO_2 cap (or cap-and-trade) environment, the guideline instructs the utility to include in its CO_2 regulatory footprint whatever upstream emissions it sees as being mandated to include by the environmental rules and regulations it anticipates or hypothecates.

<u>Observation: Different Objectives</u>[4] In reflecting upon Mr. Weiss's reiterated concerns and examples, it appears that he his concerned about "serious gaming" whereby a utility could evade accountability for upstream emissions that are produced incidental to the utility's own production or sales. To be cynical if you will, Staff's interest applies equally to when a utility *fails* to "successfully" game the system – i.e., where it must actually bear costs that are passed on to its customers. In other words, NWEC's and others' concerns are understandably regarding making sure that CO_2 emissions *environmental* costs are internalized *somewhere* – and at last resort apparently, with the retail utility. Staff's concern vis a vis the guideline is to make sure that however those costs are internalized, *or not*, that the nature and extent of the *monetary* internalization that might come to bear on the utility and its ratepayers will show up in the IRP analyses. Staff remains persuaded that no further elaboration to its recommended guideline is necessary to accomplish that purpose.

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4 A comment from Mr. Carver led to this apprehension.

Mr. Weiss's Concern-Raising Examples – With Responses

1. "Avista (in WA) want[s] to purchase gas that was made from gasified coal from outside WA to burn in a CCCT inside WA. Avista wants to do this to get around the emissions performance standard (6001) by claiming that only the emissions from the CT count [and not the emissions produced in the coal gasification process itself]."

   Under Staff's recommended Guideline 8, Avista's descriptions of its Base Case and other Compliance Scenarios would include whether or not, or to what degree and kind, Federal and State environmental regulations imposed revenue requirement burdens in the form of direct emissions taxes, fuel and electricity cost/market price increases, and regulatory cap-and-trade footprints. Whether or not Avista can succeed in getting around the subject emissions performance standard will be a legal and factual matter, where the tribunal will be the environmental arena, not the utility revenue requirement acknowledging one. Avista may or may not successfully persuade *utility* regulators of the accuracy of its IRP *projection* that, hypothetically, posits success in getting around the subject emissions performance standard.

2. "[T]he CO2 emissions related to shipping, liquefaction and decompressing of the [LNG-sourced] gas may add 30-40% to the emissions from combustion [in producing electricity]."

   Whether, or to what degree, the exporting country (where much of the upstream pollution takes place), the LNG shipping company, the transporting pipeline or gas utility, or the electric utility bear the upstream emissions responsibility will be a matter of law – hopefully attuned to practicality. But the *IRP* issue is the degree to which the state's regulated utility itself will be forced to pick up the emissions cost burden. Even if the utility were to agree that, morally, its ratepayers *should* internalize *all* the emissions costs, if those costs aren't expected to be reflected in the market price of natural gas (LNG or other), and if the Federal or State environmental regulators are not expected to mandate that the upstream emissions be included in the utility's regulatory emissions cap footprint, then it would be inappropriate for the utility's IRP to include any emissions burden beyond the expected real level.

3. "…BC Hydro buys dirty coal-fired power from Alberta at night, stores it in its reservoirs, and then resells it during higher price periods to the US….What's the carbon content of the power?....[I]f [it] is not fixed [won't it] lead to gaming as CO2 becomes more costly"?

   The pollution is visited most immediately upon Alberta, where the pollution tax, etc. should be levied. Since BC Hydro's customers would actually be consuming the dirty power (since it offsets the hydro power that otherwise would have been produced to supply BC Hydro's needs) it can be argued that if Alberta doesn't impose some accountability, the Province of British Columbia should. While the US purchaser is physically (if not economically) purchasing hydro power, not coal-fired power, it should not be expected to bear any emissions burden *unless its own environmental regulators dictate otherwise*. Again, according to the Staff's Environmental Costs Guideline, the US purchaser's IRP should specify whether or not, or the degree to which, its purchase costs and emissions footprint will be differentially affected by power purchased from British Columbia. BC Hydro can be expected to charge the market price for the power its sells, and in this example, to sell it as clean power if the price is higher and the purchasing utility (and its environmental regulators) will accept it as such.

CERTIFICATE OF SERVICE
UM1302

I hereby certify that on this, the 16th day of November, 2007, I served the foregoing UM1302 Final Comments of EMO, NWEC, and RNP upon each party listed in the attached Service List, by e-mail.

Respectfully submitted,

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Steven Weiss
For the Joint Parties

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