UNITED STATES OF AMERICA

U.S. DEPARTMENT OF ENERGY

BEFORE THE

BONNEVILLE POWER ADMINISTRATION

2010 WHOLESALE POWER	)	Docket No.	BPA-10
AND TRANSMISSION RATE	)		WP-10
ADJUSTMENT PROCEEDING	)		TR-10

ORAL ARGUMENT

TAKEN BEFORE HEARING OFFICER SAMUEL J. PETRILLO

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PROCEEDING

HEARING OFFICER PETRILLO: Good morning. It's Wednesday, June 10, 2009, shortly after 9:00 a.m. This is the time set aside for oral argument in Docket BPA-10 and sub Dockets WP-10 and TR-10. My name is Sam Petrillo. I'm the hearing officer in this matter.

The oral argument today will be held before the BPA Administrator, Steve Wright. Joining him at the front table today are other BPA executives, including Randy Roach, executive vice-president and general counsel; Dave Armstrong, executive vice-president and chief financial officer; Brian Silverstein, senior vice-president of transmission services; and Paul Norman, senior vice-president, power services.

I have a few procedural matters before we begin with oral argument. We have a very full schedule today, and so to save time, I'm planning to use the sign-up sheet in the back to register your appearances. That should save us a few moments.

In addition, we have copies of the oral argument schedule on the back table, if any of you do not have one.

In addition, I'd like to remind you to introduce yourself before speaking today and also to speak slowly and clearly so we can have an accurate transcript.

We will be also taking occasional breaks for the reporter, approximately every hour and 15 minutes, and so those will last about ten minutes or so.

Before we begin with oral argument today, I understand the Administrator has some opening remarks.

Mr. Wright?

ADMINISTRATOR WRIGHT: I want to thank all the parties for their work in this case. I think it really has been quite well done, and I appreciate that there has been a spirit of collaboration. Despite the fact that this is a rate case, there was a spirit of collaboration throughout this process.

I do want to thank the hearing officer, Sam Petrillo. From all reports, I've heard he's done a fabulous job throughout this case, and I appreciate his work on this case, as well as the clerks Patrick McAtee and James Bennett also have done great work. Thank you for your efforts on this.

And, Teresa, you've been with us for quite a while now and everyone says we can't do this without you, so I certainly hope you're going to be back for the next rate case, as well.

This is the first time in a while that we've done combined power and transmission rates and that created some challenges for us. You'll see that Paul is not joining us on the panel this morning because power and services have some issues they want to raise, and they will be represented here this morning. But there are also a number of issues that do not cross those lines, and Paul will be joining us on the panel for the rest of the session.

This has been a very interesting case in a lot of ways. There are a number of legacy issues in which we get to revisit things that we've done before, but there are many, many unique issues that we have not dealt with before, particularly with respect to the wind issues. And I, surprisingly enough - maybe I'm a glutton for punishment - I'm actually looking forward to today. It's been fun to reading through the briefs, but it's even better to actually hear from you in person.

With that, I would say we have a lot to do today. My intention, at least at this point, is to make it, even if it means we have to stay long in order to be able to get it done, so we're going to do everything we can to try to get through this in one day.

Thank you.

HEARING OFFICER PETRILLO: The first argument today is by Bonneville Power Services.

MR. MILLER: Thank you, Your Honor. Good

morning, Mr. Wright, Mr. Roach, Mr. Silverstein and Mr. Armstrong. My name is Todd Miller and I'm representing power services as a party in the TR-10 sub docket. Power services has a specific interest in one issue and that would be the persistent deviation issue.

All parties that interconnect to the transmission system have an obligation to do their part to help maintain the reliability of the transmission system. Scheduling generation and load as accurately as possible is a part of that obligation. If a generator or load ignores this obligation for an extended period of time, the reliability of the transmission system and the generation that backs up the transmission system may be compromised or threatened.

The intentional deviation penalty has been part of BPA's transmission rates since 2002. This isn't something that's new. It's been approved by FERC in several rate cases. However, power services does not believe that it has ever been enforced, and we certainly -- we're certain that it has not been enforced in the last couple of years.

And you may ask yourself, and many of the parties have asked, well, if it hasn't been enforced, if we haven't applied the intentional deviation penalty, there must not be a problem so no modification are warranted.

That's not really correct. The reason that it has not been enforced is that the current penalty language is fairly vague and it can be read to require that BPA must prove that the scheduling error was intentional. These problems make enforcement of this penalty tenuous at best. And that's why it hasn't been enforced that we know of.

The point of modifying this penalty is to make it enforceable by cleaning up the language and defining persistent deviation as four consecutive hours of deviation in the same direction, and those deviations have to be the greater of 15 percent or 20 megawatts. So we're not talking about small, just being off the schedule a little bit, but quite a lot.

Rather than arguing whether this is intentional, the proposed penalty will recognize that a transmission customer who fails to adjust schedules after four hours is acting negligently and is threatening the reliability of the transmission system.

Transmission services has proposed reasonable modifications to the persistent deviation penalty since the initial proposal. These modifications would allow for a waiver process if a customer can show that it is invested in scheduling technology and it's making real effort and the persistent deviation is just an anomaly. Power services thinks this is a good approach to applying the penalty.

Also parties have made a significant issue of changing the penalty for under-generation not being under the schedule, changing the penalty from 125 percent of the market price which it currently is to 150 percent.

Power services believes that there's some merit in the parties' arguments on this point and that the final proposal should remain at 125 percent, that moving to 150 percent is probably not warranted at this point. And it's much more important that the persistent deviation language get cleaned up and rationalized so that it is an enforceable penalty, and then we can see how that plays out. And in the future, if that's still not enough incentive, maybe it does need to go to 150 percent. But at this time, we just want something that's an actual deterrent because it can be enforced.

The persistent deviation penalty is not reinstating --

MR. ROACH: Let me stop you right there and ask you something. Cowlitz had a catchy little line in their brief and I didn't write it down exactly, but it was basically to the effect that penalties will refer to intentional acts, not unintentional ones.

You seem to be indicating, and I'm simply unclear on the issue, that if it goes on for four hours, that if it has that long of a persistence that -- what? -- it is intentional or that it must be negligent? What is the magic of four hours?

MR. MILLER: At four hours, the ramp event or whatever is causing the schedule to be that far off has been occurring for quite some time. And mind you, it's four hours in the same direction. So if a schedule tries to adjust but they over-adjust, then they're not going to be -- the penalty would not be imposed.

The thinking is that intentional is a hard standard and it's very vague. But four hours, once you've seen what your generation is doing in the first hour and the second hour, by the third hour when you have to make that schedule for the fourth hour, if you don't adjust, if you aren't paying attention, that's negligent.

Negligent, intentional, we're trying to get away from the judgment calls here. And in order to have a penalty that's actually enforceable, power services has supported the idea that it needs to be something measurable.

And again, the waiver provision is in there.

If someone qualifies under the four hours but doesn't -- but has a legitimate reason, hey, we were doing everything we could and we couldn't catch up with it, they show that they really were trying and they have a good track record of trying, that would probably be grounds for the waiver.

So the intent here isn't to collect revenue through this. It's to get people to schedule better. And getting hung up on whether someone is acting intentionally or not seems to be one of the main reasons why it wasn't enforceable before.

So one of the main arguments raised by several of the parties in their briefs is that the persistent deviation penalty is reinstating Deviation Band 3 of the generation imbalance penalty structure. And if you recall, Bonneville was kind of a leader on this way back in 2004 in working out a structure that would not impose Deviation Band 3 on wind, on variable generation, recognizing that they can't adjust their schedules during a one-hour basis. They can't predict what the wind is going to do well enough, and they shouldn't be subject to the higher penalty rate that other generators and loads are subject to. And FERC has adopted that in Order 890.

The whole argument that persists in deviation penalty is reinstating Deviation Band 3 is really a red herring. Band 3 applies to the first hour of imbalance where the natural variability of the wind can result in a schedule more or less than 7.5 percent of actual generation. And the rationale for that is still true, that variable generators shouldn't be exposed to this because they don't have enough control to meet schedules the way a thermal generator does.

On the other hand, the persistent deviation will not be applied to any schedules that are off significantly in the first hour, nor will it apply if the schedule is significantly off for two hours or even three hours. But if the schedule is still significantly off in the same direction four hours after a major ramp event, that's when persistent deviation needs to apply. And it needs to apply to send a signal that this kind of behavior is unacceptable for a customer that's interconnected to the system and has an obligation to help Bonneville maintain their reliability of that system.

Persistent deviations are the result of human failings, where humans managing the generators failed to respond to the natural variability by the third hour. We see that as very distinct from the Band 3 of generation imbalance.

Power services has submitted testimony and a brief in this case, and in all of that, we've supported and explained why persistent deviation threatens the reliability of the system. Some highlights of that is that power services' testimony notes that the hydro system's ability to provide reserves deteriorates over multiple hours resulting in unavailability of reserves when there's persistent deviation hour after hour in the same direction.

The record in this case shows that persistent deviations are fairly common. For instance, in February this year, there were 38 persistent deviation events or events that would qualify for persistent deviation under the proposed standard. The megawatthours associated with those events were 6400 megawatthours, so this is the type of thing that's moving the system quite a bit.

This also shows, the fact that that much persistent deviation is occurring shows that the Generation Imbalance Band 2 does not provide enough incentive to avoid these scheduling practices.

The record also shows that some wind generators have no persistent deviations events at all, while others have multiple persistent deviation events.

All wind generators can avoid this penalty, and the hope is that with the penalty in place, all wind generators will invest in the necessary scheduling, tools, processes and staff to avoid persistent deviation and, thus, not have multiple hours of schedules that are significantly wrong.

If BPA does not modify the existing intentional deviation penalty to make it enforceable, there will really be no check on significant scheduling deviations that last for several hours. Without the persistent deviation penalty, BPA will be forced to use DSO 216 more often.

Parties have suggested that with DSO 216 in place, no other incentive is necessary to get wind generators to schedule better. Power services disagrees with that argument. DSO 216 will only be implemented when an entire wind fleet and the load has used up 90 percent of the reserves Bonneville has set aside, and the hope is DSO 216 will be used sparingly, because if we use it all the time, that has its own problems.

If individual generators have no incentive besides Generation Imbalance Band 2, persistent deviation will occur more often and the reserves that Bonneville has set aside will get used up hour after hour and there will be less reserves in the three, four, five hours out. So that was what will cause DSO 216 to have to be used more often than we would like.

The parties to the case have cited several FERC cases pertaining to generation imbalance, and one that -- only one of those that's cited that really has to do with something similar, intentional deviation, was the PacifiCorp case. And in that case, FERC rejected PacifiCorp's attempt to institute an intentional deviation penalty saying that PacifiCorp had not backed up -- provided a record as to why this was needed or proved that it was actually happening and causing reliability problems.

Our situation here can be distinguished between the PacifiCorp case. One thing, PacifiCorp is asking for 175 percent penalty, which I think everyone thought was pretty outrageous. And in this record, we have shown that there are multiple events happening that we are not -- that this is having an effect on the system.

The other difference really is that with the hydro system, what happens from hour to hour to hour really makes a difference; whereas, with a thermal system, you can reset the system the next hour, and what happened in previous hours as far as depleting reserves, does not have the same effect.

The other difference with the PacifiCorp case is that we have had the intentional deviation in our rate schedule for several years, and all we're trying to do here is modify it rather than propose something that's absolutely brand new.

I'd like to conclude just with BPA's final decision should adopt transmission services' proposal for persistent deviation, except that the 150 percent penalty should not be adopted. Instead, BPA should retain the 125 percent penalty for over-schedules and we'll see if that's enough. If that's not having the desired effect, we could always increase that in future rate cases.

Were there any other questions before I get done?

MR. SILVERSTEIN: In the direct testimony, power services expressed concerns about the operational impacts of the testing exemption that generators get for 90 days. This has been part of the business practice in transmission services since October of 2003.

Would you please describe what and how much exposure power services is concerned with if there is an exemption for 90 days for the persistent deviation?

MR. MILLER: I think that that concern may be part of the business lines having to honor ex parte at this time. And it may be a misunderstanding of how transmission services has implemented the business practices for the test period. And I'm hopeful that once we get done with the rate case, everyone will understand or we can take a look at the business practices and make sure that there isn't a major exposure.

Power services' concern, without being able to talk to transmission services on this issue, was that if there was a waiver and the test -- a new project or several new projects coming on said, well, we just have to schedule something and they scheduled 1 megawatt for 90 days and then the system was expected to absorb the rest, that that would be a significant exposure. But it's unclear whether or not that's an issue or not. And if it is an issue, at least my belief is - not speaking for power services - my belief is that that's something best dealt with in business practices and probably not in the rate schedule.

MR. SILVERSTEIN: Thank you.

ADMINISTRATOR WRIGHT: Follow-up on Randy's question for a second.

It seems clear from the record that the parties agree that scheduling and accuracy is expensive and that there are actions that can be taken, in fact, already being taken to improve scheduling accuracy and this is in effect another tool to try to improve that.

I think the thing that we struggle with some is what is it that a wind operator should know and when should they know it? So if I understand it right, the four hours, it's actually if there is a deviation in the same hour, in the same direction, in the fourth hour, which means they would have had to take action before that.

MR. MILLER: Right.

ADMINISTRATOR WRIGHT: You would have to do it at the time of schedule, which is 20 minutes prior to the hour. So essentially that's two hours and 40 minutes to figure it out and do something about it.

Is that the right characterization?

MR. MILLER: That would be the right characterization, yes.

ADMINISTRATOR WRIGHT: Have you looked at at all what actually happens with wind and the ability to predict it and when you should know within two hours and 40 minutes what's going to happen in the next hour?

MR. MILLER: Well, if the wind's moving in a certain direction, I mean, it's applying common sense to it. It should be assumed at least move it up to where it has been.

And what we've seen, Steve, by looking at the events that was out there, what's been shown in the record is that there will be a major movement on the system and no schedule change will occur for multiple, several hours, as in nobody's paying attention.

Whether or not in two hours and 40 minutes, based on what our technical folks have said, that appears -- that's enough time with forecasting tools to be able to adjust. It maybe over-adjust some, but at least adjust to the ramp event.

In addition, we've heard throughout the case how much better the wind scheduling is getting, how with investment in some staff and some modest expense on scheduling tools, the wind is capable of scheduling much better. I believe by sometime in July, there's going to be something like 16 brand-new weather stations out in the Gorge that are providing data to help with the wind scheduling.

By all accounts, they should be able to react and figure out what's coming and where they need to move their schedule to within two hours and 40 minutes.

ADMINISTRATOR WRIGHT: It seems to me there's no question you should be able to figure out the trend within two hours and 40 minutes --

MR. ROACH: I'm going to interrupt. It would be good if both of you use mics.

ADMINISTRATOR WRIGHT: It seems clear that you should be able to predict the trend within two hours and

40 minutes, but if you can predict what will happen in the fourth hour is what I'm wondering about.

MR. MILLER: And I guess that's why it's probably important that we have that waiver language in the penalty.

If someone's invested in the staff and the time and is actually paying attention and really trying to follow this and they make a bad guess because it's a real anomaly, that they say, well, it all sure looked like it was going here, and then all of a sudden in that fourth hour, we were on top of it. If the trend stayed the same, we would have scheduled just fine. But, boy, there was just a storm cell and a big gust in that fourth hour and that's what messed us up.

Well, they can put that evidence in front of Bonneville, and by all accounts, Bonneville should waive the penalty if there's really, truly evidence that somebody is trying and they just got caught up.

But if we don't have the penalty or we have the penalty in its current form, which we haven't been able to enforce, there's a real concern that people just aren't going to pay attention, that the GI band is not enough and we're not going to get to DSO 216 until things are really, really bad.

ADMINISTRATOR WRIGHT: Did power services propose what criteria should be used for the waiver?

MR. MILLER: I believe the transmission services included language in their rebuttal testimony and power services endorsed that waiver language. And I think the waiver language is rather broad, and it may be that business practices would be appropriate to put some more refinement on the waiver language.

ADMINISTRATOR WRIGHT: Thank you.

MR. MILLER: Thanks a lot.

HEARING OFFICER PETRILLO: Thank you, Mr. Miller.

Next up is Northwest Wind Group.

MR. HALL: Thank you, Your Honor. Good morning. My name is Stephen Hall. I'm here on behalf of the Northwest Wind Group.

The members of the Northwest Wind Group include BP Alternative, Columbia Energy Partners, enXco, Verizon Wind Energy, RES North America and the Renewable Northwest Project.

I'd like to thank the Administrator for the opportunity to speak directly this morning about the issues about wind integration, and I'd like to thank you about sending out the questions in advance. I plan to address those later this morning.

But before I do so, I'd like to take a few minutes to briefly summarize the concerns that the Northwest Wind Group has regarding BPA's proposed wind integration rate.

First, a quick review of how we got where we are. Before the 2009 rate period, BPA did not have a wind integration rate. When the wind fleet was less than 800 megawatts, the variability of load masked the variability of wind generation, and BPA did not recognize the cost associated with balancing wind.

As the wind fleet grew past 800 megawatts, BPA had to make certain operational changes to accommodate wind and sought to recover the costs associated with this.

Pursuant to a settlement in 2008, BPA adopted a wind integration rate for 2009 of 68 cents per kilowatt month, which is about $3 per megawatt hour. For 2010, BPA's initial proposal now recommends a rate of $2.72 per kilowatt month or about $12 a megawatthour. That's a rate increase of 400 percent.

MR. ROACH: Excuse me. Early in this case you had written me about Bonneville's adherence to the rate case settlement. And in your testimony and now again, you are making a point to the effect that Bonneville is proposing a 400 percent increase. And that's an increase over the amount that was settled; isn't that correct?

MR. HALL: That is. And I'm not arguing that that's precedential, that the earlier rate amount is precedential --

MR. ROACH: If you make that statement, the implication is that the base amount had some appropriate basis to it.

MR. HALL: Randy, if that's the implication that you draw, that's your implication. As I'll discuss later on, there are fundamental legal problems with the rate that Bonneville has adopted for the wind integration rate that are completely independent of the earlier settled rate. I was just going through the history of how we got to where we are today.

MR. ROACH: So --

MR. HALL: I'm not relying on precedence for the difference in the rates.

MR. ROACH: So we should not rely on the rate that was settled upon as a reference point for what the correct rate is; is that correct?

MR. HALL: Not necessarily.

MR. ROACH: Wait a second. Not necessarily or not at all? Given the settlement agreement that your client signed, said that the signatories agree that they will not - and I'm going to skip over some language -

create or imply any procedural or substantive precedent or creates or implies agreements to any underlying principles or methodology.

So to me that's saying that, you know what? The parties settled out on this rate and they are not agreeing that it is or is not the correct level. Do you disagree with that?

MR. HALL: Nothing in that language said anything about the rate level, but I'm not arguing that that is precedential. I think the 2010 rate needs to stand on its own merits, and that's what I want to talk about.

MR. ROACH: And it shouldn't have reference --

MR. HALL: Without reference. I'm not relying upon the settled rate.

MR. ROACH: Thank you.

MR. HALL: I think that's a good clarification. I appreciate that.

So the level of the rate, the 2010 rate is due to significant policy changes that BPA has made in how it determines the quantity of reserves needed for wind and the types of costs that BPA has decided to assign to wind integration.

The problems in BPA's wind integration methodologies and policies are numerous, and I will not be able to cover them all this morning. But what I would like to do is focus on certain key policy decisions that have contributed to an overstatement, the quantity of reserves and an overestimate in costs.

With respect to quantity, one of the biggest decisions that Bonneville made for the 2010 rate was to begin charging wind for reserve amounts associated with imbalance capacity. This added a new component to the wind integration rate. This decision alone added a $1.81 per kilowatt month to the 2010 rate or about $81 million to the revenue requirement.

This decision was discriminatory because customers taking generation imbalance service and customers taking energy imbalance service do not pay a capacity charge. They simply pay the energy charge.

MR. ROACH: Discriminatory or unduly discriminatory?

MR. HALL: Unduly discriminatory.

MR. ROACH: And you're saying, then, that all other generators are similarly situated to the wind generators?

MR. HALL: According to the testimony of Bonneville Power Services, within the hour, the provision of within hour balancing services, it's either an inc or a dec. It's an up or down. And for some of the ups and downs, some of the incs and decs, there is a capacity charge and other charges that are associated with that. And for load and for non-wind generators, there is just an energy charge.

MR. ROACH: That's not answering my question. That's stating what the charges are. You're making the assertion and have made the assertion that the wind, as a generation group, is being discriminated against, and I asked is that undue discrimination.

The basis for undue discrimination is one where there is no basis in fact for the discrimination. And so I'm asking you is wind similarly situated to -- as other generators?

MR. HALL: With all respect, I disagree with the perspective that you're taking on framing the question. From business power services' perspective, the provision of what they -- the product they provide, within hour reserves, it's either a plus or a minus. And for some of the customers, the pluses and minuses who admittedly buy a lot more of that product, they are charging them for capacity.

MR. ROACH: So you're not going to answer my question.

MR. HALL: I disagree with it.

MR. ROACH: So you're not going to answer my question.

MR. HALL: I'll continue.

The second point in quantity is 120-hour peaking capacity. This is a measure of how Bonneville determines the amount of capacity reserves that are available to provide within hour balancing. And Bonneville reduces the instantaneous capacity of the FCRPS by a measure of 120-hour peaking capacity, which is a measure over a six-day period, how long could they meet sustained levels.

And Bonneville, its application of that measure to the amount of reserves that would be available for wind has greatly increased the cost of wind. Bonneville has performed absolutely no analysis whatsoever to support the use of this measure for wind.

Finally, on the subject of quantity, at a very late stage in this rate case, Bonneville revised its generation reserve forecast for load, which further increased the amount of reserves allocated to wind, even though no assumptions related to wind had changed.

With regard to pricing, in anticipation of this case, Bonneville adopted two new policies, which it noted in its Federal Register Notice. The first was the decision to charge a capacity charge under the wind integration for imbalanced energy, which we just discussed and which added $81 million per year to the revenue requirement.

And the second was the decision to create a new variable cost pricing methodology to replace the AGC adder from the 2000 rate case and earlier rate cases. Because many of these new charges overlapped the charges under the generation imbalance charge, BPA's wind integration rate now collects multiple charges that are excessive and duplicative. And as a result, for each megawatthour of imbalance energy that Bonneville provides to a wind generator, Bonneville will charge that wind generator a capacity charge, two energy charges and an opportunity cost charge. In contrast, customers of generation imbalance and energy imbalance pay only the energy charge.

With respect to the legal standards, we believe that Bonneville's wind integration rate does not comply with Section 7(a)2(c) of the Northwest Power Act, which requires Bonneville to equitably allocate its transmission costs between federal and non-federal users of the system. We believe that it does not satisfy the Commission's comparability standards because it violates the "or" pricing policy of FERC, and we believe it violates Section 212 of the Federal Power Act.

With respect to the persistent deviation penalty, we believe that that is discriminatory wind-only penalty --

MR. ROACH: So this is a question for me looking for understanding. You say that it violates comparability because it violates the "or" standard?

MR. HALL: Yes. And because it's excessively duplicative.

MR. ROACH: I was thinking comparability applied basically where the transmitting utility was treating basically its marketing arm different than other transmission customers. And so I'm trying to understand how the violation of the "or" test violates the comparability standard.

MR. HALL: That would be because your open access transmission tariff, which would refer to your transmission schedules, the rates charged under there are not permissible under FERC's pricing policies, so your open access transmission charges would not be consistent and would not be entitled to comparable treatment under Order 888 and Order 890.

MR. ROACH: I think you mean the reciprocity agreement.

MR. HALL: It would not be entitled to reciprocity.

In addition, and I just want to make sure that

I've made this point, that the persistent deviation penalty would also not be consistent with Order 890 and its treatment of intermittent resources under the generation imbalance charge.

Bonneville's proposed wind integration rate is also not consistent with Bonneville's obligation under the Northwest Power Act to encourage the development of renewable energy. It's also at cross purposes with the policy direction of Congress and the Obama Administration.

Congress is spending billions of dollars to encourage renewable energy development and jump-start the U.S. economy at the same time that BPA is raising the wind integration rate by 400 percent.

I'd like to turn to the Administrator's questions. The first question you asked was that in the context of self-supply, how should BPA address the potential revenue variability arising from self-supply?

In our initial brief, we recommended that the Administrator adopt the mid period rate adjustment mechanism to reflect a change in installed wind capacity due to self-supply or the establishment of new balancing authorities.

We also suggested that BPA run the studies and prepare the rate schedules in this proceeding so that such an adjustment could be automatically implemented without the need for a further 7(i) proceeding.

I must also point out an inconsistency between the concern about revenue variability and BPA's testimony in this proceeding. According to BPA's testimony, the wind integration rate "recovers the costs BPA incurs for setting aside and using balancing reserve capacity to balance the output of wind resources within hour." And that's from TR-10-E-BPA-07, page 18.

So if BPA is not incurring the costs of setting aside and using balancing reserves to capacity for wind, and is able to use that capacity to make market-based secondary energy sales, any loss to self-supply should be revenue neutral.

However, as we've argued in our testimony and briefs, the wind integration rate is not cost-based. Under its proposed rate, Bonneville will make a greater profit from selling within hour reserves to wind generators than it could ever get from using that capacity to make secondary energy sales in the market. The solution to Bonneville's revenue variability dilemma is simple: Adopt a cost-based rate that is truly revenue neutral.

The next question was for wind generators, how sensitive is your decision to self-supply to the level of BPA's wind rate?

In our view, the level of BPA's wind integration rate is the primary driver of the decision to self-supply. But I think that your question seeks to find out what the threshold of pain is or how much of the rate increase can be afforded. And on this, I think the best data point is the testimony and the briefing of Iberdrola, who stated very clearly that it will pursue self-supply if the wind integration rate exceeds a dollar per kilowatt month. I think also as the market evolves and other providers come into the market, that that number will go down.

The next question was: It appears there is a significant number of curtailments associated with the 30-minute persistence. Are the wind generators and receiving balancing authorities prepared to accept that number of curtailments if we operate at a 30-minute persistence?

Based on the most recent information provided by BPA staff, we estimate that the amount of wind that would be curtailed at a 30-minute persistence level of accuracy. So if the wind generators were scheduling at a 30-minute persistence level of accuracy, it would be approximately two hours per month. If the wind generators were scheduling at approximately 60 minutes per month, it would be four hours per month.

The Northwest Wind Group supports the idea of BPA holding an amount of reserves based on 30-minute persistence and using the reliability and operational mechanisms to manage those reserves.

The next question was: In the context of the assumption about the scheduling accuracy of wind generators to set the wind balancing rate, to what extent should BPA factor in a reliance on DSO 216 currently being developed?

The Administrator's question refers to DSO 216 which is the shorthand for the reliability and operational requirements established by the wind integration team. Under the WIT protocol, BPA would instruct wind generators to reduce output when BPA is close to exhausting the total amount of dec reserves available for balancing.

In addition, BPA would be able to revise wind transmission schedules within the hour, when actual wind generation is far below schedule and BPA is close to exhausting total inc reserves. If BPA uses these WIT protocols, it would be able to reduce the amount of reserves and could lower rates accordingly. The testimony here is WP-10-E-BPA-22 at page 20.

According to BPA's testimony, the wind fleet is currently scheduling at 60-minute or better accuracy. Our testimony showed based on a recent sample that scheduling accuracy is closer to 30 to 50 minutes.

If BPA is simply going to hold an amount of reserves equal to the amount of reserves needed to balance wind at current accuracy levels, say, 60 minutes, then there really is no need for the WIT protocols because we're already there. But to the extent that BPA is willing to delink the reserve requirements from the question of scheduling accuracy, then there would be a purpose and role for the WIT protocols.

The question here is can it be done? BPA has testified that it's possible to delink the two. Bonneville has already demonstrated an ability to curtail wind, so operationally it seems doable, and at least speaking on behalf of the Northwest Wind Group, our members like this approach because it allows the most accurate wind generators to benefit from the lower overall rate while encouraging other wind generators to improve their scheduling accuracy.

The next two questions were: How should BPA factor into its persistence decision the likelihood that some parties may challenge the implementation of DSO 216, and what assurance can you give BPA now that you will not challenge the DSO 216?

In the interests of time, let me answer both. If BPA's adoption and its implementation of the WIT protocols is consistent with BPA's testimony, I do not anticipate a challenge.

If BPA seeks additional assurances, perhaps such assurances could be part of a non-precedential settlement agreement resolving all wind integration issues for the rate period. Understandably the members of Northwest Wind Group would not be able to agree to waive the right to challenge the WIT protocols if BPA changes them or implements them in a manner that's inconsistent with BPA's testimony.

I would also suggest that BPA consider publishing after-the-fact system reports describing the curtailments to provide transparency to the process and to avoid misunderstandings.

But let me emphasize that our members are supportive of BPA's use of operational protocols to limit the need for within hour reserves helps for wind and to reduce the wind integration rate.

The final question was: Do you believe that small wind generators should be exempt from the wind integration rate?

We are only aware of one small wind project right now that's out there. It seems viable. It's a 10 megawatt project. It's in Oregon. It doesn't seem that would have a material effect on the rates one way or the other.

Our recommendation would be that the Administrator exempt this project and similar projects from the wind integration rate for this rate period and then take a fresh look at it at the beginning of the next rate period.

In closing, let me add that over the next two years, BPA, the wind community and other stakeholders are going to be working to implement intra-hour, self-supply, third-party supplied dynamic scheduling and other operational improvements that are going to significantly reduce the amount of reserves that are needed for balancing wind. And so right now, we're in a period of transition.

And there are several factors, including recent documented improvements in scheduling accuracy, the ability to use the WIT protocols, suggesting that BPA's cost of providing balancing reserves during this rate period will decline.

Therefore, our recommendation is that the Administrator either hold the wind integration rate flat for the 2010 rate period, as it did for other transmission rates under the partial settlement agreement, or adopt a non-precedential rate of 75 cents per kilowatt month for the rate period, which would represent a 10 percent rate increase and which would be in line with the expected rate increase for the PF rate for the preference customers.

This approach could be but would not necessarily need to be accomplished under a non-precedential settlement agreement that addressed other wind integration issues for the rate period.

In the alternative, we recommend that the Administrator direct BPA staff to revise its methodologies, to adopt an appropriate cost-based rate for wind integration service to be consistent with FERC's transmission pricing policies. This would mean that the rate would be capped at the higher of either BPA's imbedded or its opportunity costs, what BPA refers to as its variable cost methodology.

Under either of these proposals, BPA's wind integration rate would more accurately reflect the real cost for providing wind integration service for wind generators, would bring the BPA's current renewable energy policy back in line with both BPA's historical support of renewable energy and the renewable energy policies of Congress and the Obama Administration.

Thank you.

If you have further questions, I'd be delighted to take them.

ADMINISTRATOR WRIGHT: I've got a whole bunch, actually.

MR. HALL: Excellent.

ADMINISTRATOR WRIGHT: If you add all these charges together, what do you estimate the total cost per megawatthour is for the wind services?

MR. HALL: The charges in BPA's initial proposal?

ADMINISTRATOR WRIGHT: Yes.

MR. HALL: $2.72 per kilowatthours.

ADMINISTRATOR WRIGHT: Translate that into dollars per megawatthours.

MR. HALL: About $12.

ADMINISTRATOR WRIGHT: Is it your position that $12 a megawatthour would so fundamentally alter the market that renewable energy development would slow substantially in the Northwest as a result of that with wind prices currently at above $100 a megawatthour and alternative resources appearing to be substantially more than that? And if so, what resources would substitute when you add a $12 megawatthour charge?

MR. HALL: So you have a couple of questions in there.

The first question is would it make a difference -- let me step back. I think that the level of the rate is not determined based on what market is, but it's based upon cost-based principles. I think that the WP-10 rate for wind integration is not cost-based.

ADMINISTRATOR WRIGHT: I'm asking a different question.

MR. HALL: I understand. But to the extent that is the rate too high? Iberdrola in their testimony, they said if it goes above a dollar that they can self-supply at a lower cost.

ADMINISTRATOR WRIGHT: That's a different question. The question is that the point in your testimony is that these charges would substantially alter the marketplace such that renewable resources development would be slow in the region.

Renewable resources are being developed presumably to meet load, so you have to substitute some other resource. So what other resource is going to substituted when you add $12 charge to wind? I'm just unaware of any resources that are out there that a $12 addition to wind, especially with renewable portfolio standards in the region, that a $12 charge would change the economics that dramatically.

MR. HALL: I think at that price level, that biomass would be competitive. Geothermal would be competitive.

ADMINISTRATOR WRIGHT: Those resources would, presumably, they have some intermittency as well and would have to pay some of these charges, too. So you have to address the fact that they're going to pay some of those charges as well, right?

MR. HALL: Geothermal is a base-load resource and biomass is dispatchable, as well.

ADMINISTRATOR WRIGHT: Your view is that a $12 would make biomass, which is currently not cost effective, cost effective and the same with geothermal. Am I understanding what you are saying correctly?

MR. HALL: I think you're a little bit out of my expertise range to evaluate the economics of different resources, but a $12 surcharge on wind energy, definitely it's a game changer.

ADMINISTRATOR WRIGHT: Where is the break point? $6? Where is it at?

Candidly, your brief is filled with some fairly heated rhetoric in the beginning: Contrary to Obama Administration policy, will stall renewable resources development in the region. I'm looking for some facts to back that up. Where is that break point in terms of dollar per megawatthour charge that will cause wind to no longer be cost effective?

MR. HALL: The determination whether wind is cost effective, ultimately renewable energy has been sold to utilities and primarily it's investor-owned utilities that provide renewable energy under state renewable portfolio standards, and the prudency of that is determined by the state utility commission.

Each state has a different statutory scheme for whether there's a safety valve and it's considered too expensive and the utility doesn't need to purchase as much renewable energy. It's a complex question that is hard to just give a short answer to.

ADMINISTRATOR WRIGHT: To help you out, I actually don't think it's that complex a question.

The fact of the matter is it seems -- I'm struggling to understand the basis for the statements about how these charges will so fundamentally alter the market. And if it were to alter the market, given the alternatives that you suggested, it would be geothermal and biomass. Those are alternative renewable resources. And so it's not that renewable resources would not be developed; it may have an effect on wind, if you accepted your premise, which I'm still struggling with.

Let me switch subjects. Do you believe that the rate itself will change much as a result of self-supply? Because presumably if you -- if we go to self-supply options, the costs will be reduced as well as the megawatts, either a numerator or a denominator change. What's your perspective with what happens to the rate?

MR. HALL: There's a lot of moving parts. And the question is does a reduction in supply just move the rate linearly or is there some kind of iteration between some other variables?

When the wind fleet was at 800 megawatts, there was -- Bonneville observed no cost to balancing wind at that point because the variation of wind was offset by the variation of load.

If enough customers opt for self-supply, as you would start to approach that 800 megawatt amount, you're back to the point where Bonneville recognizes no cost. So it would seem that as you reduce the amount of installed wind capacity served by Bonneville that the rate would come down.

And this is, frankly, a new enough development in the rate case that Bonneville hasn't run new studies and there's just not enough data to look at to determine this, which is, in part, why we asked that in this case Bonneville rerun the studies and prepare the schedules

to address that so that it wouldn't be an open issue.
ADMINISTRATOR WRIGHT: You proposed to keep the rate where it's at or a 10 percent increase or an alternative rate that was based on imbedded or opportunity costs. Did you calculate what that rate would be under that alternative and the other proposals that you've made?
MR. HALL: In our -- I believe in our initial testimony, we calculated the rate based upon the information in the initial proposal, and that was at the imbedded costs. I believe it was approximately $1 per kilowatt month. It was one of those things where it coincidentally calculated out almost to an even number.
Since that time, there has been several adjustments in the rate case. Some that have moved the number down; some that have moved the number down. BPA staff is waiting to run the final studies.
So in a sense, and I think I'm not alone in having this feeling. We're not really sure where we stand with all of these adjustments of where things would shake out at this point, just looking at the imbedded costs or just looking at the variable costs. But in our testimony, based upon the initial proposal, about a dollar.
ADMINISTRATOR WRIGHT: So in preparing for

this, I asked folks how many SGIAs we have that, therefore, would be exempt from the charges, and the numbers I've got are probably four to five times the magnitude of your numbers. Being that it is still at large, it's probably closer to 80 to 100 megawatts.

MR. HALL: Well, you know the difference may have been a misunderstanding. Small generator interconnection agreements, and I guess maybe I wasn't looking at that in a technical way, but I think that break point is 20 megawatts.

ADMINISTRATOR WRIGHT: Yes.

MR. HALL: So we were looking at ten megawatts.

ADMINISTRATOR WRIGHT: You're proposing a potentially a different standard.

MR. HALL: Potentially different. And given if you tell me that it's 800 megawatts or whatever the amount is --

ADMINISTRATOR WRIGHT: No. It would be 80 to 100, somewhere in there.

MR. HALL: -- we'd probably want to think about that a little bit more.

ADMINISTRATOR WRIGHT: So I assume you'll address that at some point?

MR. HALL: Yes.

ADMINISTRATOR WRIGHT: I want to come back to this question of the trade-offs between setting the rate with greater scheduling accuracy and the impact on the DSO. So it certainly is my expectation that we would operate in terms of holding reserves consistent with the decisions that are made in the rate case. And so if we go with the lower persistence forecast, then that would mean that we would carry less reserves and there would be more curtailments, presumably.

I was a little perplexed by your numbers, and it could be that I wrote them down wrong. It sounded like you said you would expect two hours per month curtailment for 30-minute persistence, but four hours per month for 60 minutes. I would have thought that the ratio would have been the other way around, greater curtailments for a lower persistence because of holding less reserves.

MR. HALL: So this information is based on Bonneville's data, and it is that if BPA held reserves equal to 30-minute persistence and if generators were scheduling at an accuracy level of 30 minutes, that the curtailments would be two hours a month.

If Bonneville is holding reserves at the 30-minute level of persistence and the generators are scheduling at an accuracy level of 60 minutes, then it would be four hours.

I wasn't clear about that, but what I meant was that in each case you're holding 30 minutes of reserves. In one case, we're at 30 and at the next one we're at 60.

ADMINISTRATOR WRIGHT: Okay.

MR. HALL: The point is the same, is that even at 60 minutes persistence, we're looking only at curtailments of four hours per month, and the savings there is significant.

ADMINISTRATOR WRIGHT: So we're all learning about this stuff, and I think it's just not clear whether that's how much curtailment there would be.

I understand there was some evidence that the WIT team put out as to greater curtailments as to the types of occurrences that you're talking about, potentially two to three times that, at least is my recollection. So you may not be able to hold me to that because I'm just having a little bit of a vague memory there.

What I'm really trying to get to is that there's a trade-off here for the wind community: Lower rate versus higher curtailment, or the other way around. And I think what you're saying is you're prepared to accept greater curtailment for a lower rate, at least in this range.

What if it was doubled or tripled that in terms of the number of curtailments? What if it was eight, ten, 12 curtailments per month for 30-minute persistence forecast operating at 60?

MR. HALL: I think we'd need to look at those numbers and know what the upper bounds of that to understand the trade-off.

However, my understanding is that at the two- to four-hour curtailment range, that it's something like we save $10 of wind integration rate for every dollar of cost that we would incur, so it's significant.

ADMINISTRATOR WRIGHT: Say that again. I want to make sure I understand your point.

MR. HALL: This is just based upon informal discussions, back of the envelope, but our understanding is that the trade-off in the rate of moving down to 30-minute persistence and if we are being curtailed at the range of two to four hours per month, that the savings there could be up to -- for every dollar of costs that we're incurring through the curtailments, so that's loss of PTCs, green tags, the energy sales, that we are saving as much as $10 in the wind integration rate. And we might be able to do a more precise calculation on that, if that would be helpful.

ADMINISTRATOR WRIGHT: Again, I haven't ever thought about this, so I want to make sure I understand what you're saying.

If there is a single curtailment, it costs you a dollar per month. The ratio at least would be a dollar per month to $10 a month of savings in the rate. So if there are two curtailments, does the ratio become $2 to ten, or $4 to ten?

MR. HALL: As I said, this was just a rough back-of-the-envelope estimate. I'm sure that we can prepare something more detailed.

But if you took 100 megawatt wind project and you say we're curtailed for one hour, what's the loss of the PTC, the green tag, the energy costs, multiply that times 100, multiply it times two hours or four hours and then compare the rate that's proposed in the rate case versus a rate that's at a 30-minute persistence level, that the trade-offs are just very favorable.

ADMINISTRATOR WRIGHT: That's the part I'm trying to understand, whether you're doing it on the basis of a two- or four-hour or whether that was just for one hour. Because if it's one hour and if it turns out there are more curtailments per month, your one-to-ten ratio changes dramatically.

MR. HALL: I would agree with that, but the attraction of moving to this model is that the risk is within the ability of the wind generator to control through better scheduling, through -- more resources on that end, the number of curtailments could be managed. So it's not something that's independent.

I was talking with someone earlier, in a way this is analogous on the use of the PF rate on the CRAC. Customers accept a lower PF rate and assume some risks, but in that case, it's external events that they can't control. In this case, scheduling accuracy, each wind generator has the ability at some level to improve their scheduling accuracy and reduce the amount of curtailments. It's a risk that we can manage. And that's why we think this is a workable proposal.

ADMINISTRATOR WRIGHT: And I guess, given that we're having this conversation, you would suggest that we could have some confidence we wouldn't hear from the wind community a year into this, that if there were eight to 10 curtailments per month, that, gee, this just didn't work out the way we thought it would and something needs to change here. You need to increase the amount of reserves you're carrying on the system.

MR. HALL: In general, yes, subject to the caveat --

ADMINISTRATOR WRIGHT: As 216 was put in place.

MR. HALL: That's right. As BPA changed the way that they're implementing them. As long as it's implemented consistent with the principles enunciated in the testimony, I don't anticipate a challenge.

ADMINISTRATOR WRIGHT: I tried to get this as a quote, but I'm not sure I got it, and I didn't understand your point. We're on the same subject, but you said BPA should delink the protocols from a persistence forecast for rate decision-making. What did you mean by that?

MR. HALL: What I meant was - and this is in BPA's testimony - is that through the use of the WIT protocols, it's possible to - their word was delink. I like that term - to separate the calculation of the amount of reserves to be set aside from the question of how accurate are the wind generators scheduling.

So instead of setting the level of reserves based on current scheduling accuracy to say, okay, wind generators are scheduling around 45 minutes, but we're going to hold reserves at 30 minutes. And so that's the concept of delinking is to do those two calculations separately and then use the WIT protocols to manage the schedule inaccuracy of wind generators down to match the level of the reserves that Bonneville is holding.

ADMINISTRATOR WRIGHT: I'm in over my head at the moment because I don't know what the WIT protocol said.

But I'm a little concerned about -- the point that I was trying to get to before was that the wind group would agree that our conclusion here with respect to how we set the rate and the level of reserves we'd hold should be what we use for operating purposes. In other words, that we're not going to make one decision here and another decision there. We're going to do something to keep the rate low but then hold higher reserves because it will result in less curtailments. I hope that --

MR. HALL: We're not saying that. I'm just saying for purposes of setting the rate, we establish the amount of reserves, and during the rate period, manage to that level of reserves that you set in the rate case.

ADMINISTRATOR WRIGHT: That's what I wanted to make sure on.

Your point with respect to generation imbalance services, so I'm not sure if I'm understanding, you make this point that it's discriminatory treatment, and there was this $81 million capacity charge that you think is duplicative. Are you saying that you think that charge should be zero?

MR. HALL: No. And in our initial testimony and in our initial brief, what we recommended is that -- in the next rate period that Bonneville move to a generation imbalance charge that has a capacity component but that all customers pay, non-wind generators, and for the energy imbalance charge that load would pay a capacity charge, also.

ADMINISTRATOR WRIGHT: Did you estimate what that charge would be for the wind folks? How much of a difference would it make in the rate?

MR. HALL: I didn't calculate that amount. And during clarification, I asked BPA staff if they had calculated the amount of -- the value or the cost of the capacity that they would have to hold for generation imbalance and for energy imbalance, and they said that they'd never looked at that. So there really wasn't much of a basis to make that adjustment.

ADMINISTRATOR WRIGHT: I think those are my questions.

There are a couple of places where you suggested follow-up. I wonder if Randy could give us some advice about where that could happen, because I'm not sure if, given where we are in the process, what we might offer in terms of a suggestion for that.

MR. ROACH: So I think with the permission of the hearing order, you can request that -- I would suspect if they provide information, other parties are going to want to provide information on the question, so it might be one of those things - I'll try something and then I'm sure people will weigh in - is if perhaps Steve's clients could and other parties in response to the same question, if they want to, could provide an answer to those questions within, say, five days. And then in the event that --

MR. HALL: Could I interrupt? Could I offer a suggestion? Perhaps from the general counsel's office or the Administrator's office, you can send out a letter and say there was a couple of follow-up questions from oral argument and then everybody can just reply at once, and then everyone would know what those questions were.

MR. ROACH: My concern is, I've seen it in the past, is that sometimes these things could call for fairly factual questions that generate a position, well, wait a second. I want to respond to the information that was in that party's response. But maybe that's sort of one of those things that -- I'm not adverse to sending out the request, again, with the hearing officer's permission, but might anticipate that other parties would want to opportunity to respond.

ADMINISTRATOR WRIGHT: So how about if we do this. There are two issues that I'd heard. The one is if the small -- if we're using the small generator connection agreement as the definition of small wind, it's probably more like 80 to 100 megawatts, does your group have a different version of this question? And the second is the ratio that you've got that I still don't quite understand of the rate versus the cost of curtailment.

But having said that, I hadn't anticipated we'd find ourselves in this position, and I don't know that -- I really don't want the rate case to be off schedule. That would be actually more important than getting the information.

So we need to maybe have a little discussion and see how the rest of the day goes in terms of what other questions come up before we decide how to pursue this, or if we should pursue it.

MR. BURGER: This is Peter Burger.

One of the things we could do is have those questions answered in the briefs on exception. We'll see those after they get the draft ROD. If there are -- if parties deem it necessary to have some kind of follow-up, we could probably work something into the schedule at that point. But we at least have those coming up in the near future.

ADMINISTRATOR WRIGHT: So let's keep that as an option and see how the rest of the day goes.

MR. HALL: Thank you very much.

MR. ROACH: I have a question following up on some of Steve's questions.

You've made a fairly strong point, as Steve pointed out, about Bonneville's rate proposals being inconsistent with the Obama Administration policy in developing wind and have suggested Bonneville rely more on the DSO 216 as detailed in BPA's testimony, which begs the question whether it would then be your client's position that curtailment pursuant to DSO 216 as detailed in BPA's testimony would be consistent with the Obama Administration policy.

MR. HALL: I think to the extent it enables the wind integration rate to come down and more wind energy to be developed, I think it would be consistent with the Obama Administration's policies on renewable energy.

ADMINISTRATOR WRIGHT: Thank you.

HEARING OFFICER PETRILLO: Thank you, Mr. Hall.

Our next argument is scheduled for 25 minutes, so I'm thinking this might be a good time for a short break. Let's recess for ten minutes.

(Recess taken.)

HEARING OFFICER PETRILLO: We're ready to get started again.

Next argument is by Iberdrola.

MS. SKIDMORE: Thank you, Your Honor. Good morning, Mr. Roach, Mr. Silverstein, Mr. Wright, Mr. Norman and Mr. Armstrong. I'm Lara Skidmore representing be Iberdrola renewables. And I'd like to thank you all for the opportunity to talk to you today.

I would like to begin by noting that Iberdrola very much appreciates the efforts of BPA staff and management to work with us on these wind integration issues over the past few months. Despite these efforts, at this point, the proposed wind integration rate still appears likely to be established at a level that is going to be uneconomic for Iberdrola.

Absent a substantial change to the final rate level from what we've seen in Bonneville's direct and rebuttal case, it would be more economic for Iberdrola to self-supply one or more components of the wind integration rate rather than face exposure to the entire rate.

We're pleased that you're working with us to enable self-supply and to avoid what Iberdrola considers to be a more complicated and a less desirable outcome in the formation of a separate balancing authority area. But Bonneville, let's continue to work with parties to expeditiously enable self-supply and to include a rate mechanism in the final ROD that will provide a credit to parties to elect self-supply and thereby reduce the reserve burden on the BPA system.

I have a few observations about the process that has gotten us here today. Again, Iberdrola has actively worked with BPA and others both before and throughout this rate case in an effort to find an approach to wind integration that will work for the entire region. We have come up with a lot of creative solutions, many of which had great potential and in some cases even brought appeal. Yet Bonneville has been unable to really entertain or work on our proposals claiming in most cases that they were simply too complicated to explore or implement in the time frame that was available.

And unfortunately in some cases, this was long before the rate case even commenced, so the message we have consistently gotten is that it is already too late and the studies have already been run and there's really no time to consider or develop other approaches, anything that was other than a really relatively modest types of changes.

And this has been frustrating for us, obviously. We kept trying. And it isn't because people didn't want to talk to us or try to work with us. It just seemed to be this sort of reality that there was not an ability to do a whole lot more.

We did note you've had a lot of time to work with the power customers to deal with their complicated issues throughout this case, and we realize that there are a lot of competing priorities for the Agency, and there's only so much staff and there's only so much time. But unfortunately, I think the message to the wind community in part has been that there just hasn't been enough time to really properly address the wind integration issues. We haven't had enough time to collect enough accurate information to do all the studies we needed to do and not enough time to consider the creative solutions that were being put together.

I recognize some of those did involve a measure of complication that isn't part of this case, but it also in many cases addressed, I think, the issues that we're struggling here most at the very end.

So the result appears to be a wind integration rate that is going to overstate the amount of the generation reserve requirement for wind and consequently overstate the costs to integrate wind in the Bonneville balancing authority area.

The rate level that's being proposed by BPA, including the adjustments and the allocations made during the case is simply too high and is uneconomic for wind generators. We believe a wind integration rate of this magnitude will drive wind generators to explore other alternatives, including self-supply, formation of separate balancing authority areas.

And to follow up on a question you had for Mr. Hall previously, what I think a rate at that level is likely to do is just to push developers to other regions. It's not necessarily going to stop wind generation, but it's going to send them to locate their resources in regions where they don't have to pay such a high wind integration charge, or in most cases, any additional wind integration charge. So that's -- the resource development and the jobs and all the other things that go with that.

But clearly there are important policy considerations involved here. As you know, Bonneville has a legal obligation under the Northwest Power Act to encourage renewable energy within the Northwest, and the new Administration has made renewable resource development a priority.

You've also received increased federal borrowing authority to construct new transmission projects for the intended purpose of enabling significant new wind generation in the Pacific

Northwest.

MR. SILVERSTEIN: So one point that you just made that may be more attractive to move to other regions where there are not separately identified wind integration charge, is it true that these are generally in areas with active markets where, in fact, the loads are, in fact, paying all the costs of integration through, for example, ten-minute market?

MS. SKIDMORE: I think that may be true in many of the cases. I don't think that's true in all cases, however.

We would hope that in the face of the statutory and federal directives, Bonneville will not promulgate wind integration rates that discourage or render uneconomic wind generation in the Pacific Northwest.

At this late stage, absent an adoption of an approach similar to that advocated by Iberdrola in our initial brief, it seems that Iberdrola will have little choice but to proceed down an alternate path.

But as discussed in our brief, we believe there are a number of errors in the analysis and assumptions used to develop the proposed wind integration rate. We believe the scaling methodology is flawed and it's based on an insufficient amount and type of data and that it fails to accurately measure or take into account the magnitude of wind ramp diversity.

We think that if the scaling were done correctly, there would be recognition of the wind ramp diversity that would result in a decrease in the reserve requirement and the associated costs for wind.

We continue to believe that scheduling persistence forecasting accuracy levels should be set at 30 minutes. Iberdrola has taken significant measures to increase its scheduling accuracy, including hiring a 24 by 7 shift of the meteorologists, which is in place as of June 1, to data scheduling based on their experience, both with Pacific Northwest weather patterns and the specific terrain. Because as we know, when the wind blows, it doesn't just blow straight across. There are lots of different and interesting wind pattern activities that result, which is why the scaling methodology is, in our view, flawed in ramping effects that are not what you would normally predict if you were just assuming it was blowing in one direction.

It does a lot of different things and it requires that kind of skill, meteorological analysis to anticipate what a particular weather system is doing and how that is going to impact the various generators.

But in the short time that we've had our meteorological staff in place, beginning in February of this year, we have seen a dramatic increase in our scheduling accuracy and are feeling very confident that we will be at or below 30 minutes throughout the rate period.

So this expertise combined, not only will we have more people working 24/7, but we're going to have more and better information from the monitoring sites, many of which you are installing. And those are expected to be installed, I believe, before the beginning of the rate period. And this will enable Iberdrola to achieve a 30-minute level of scheduling accuracy.

And we also think that others in the industry can hire or contract for these same services. They will similarly have access to the additional wind monitoring site information, and we believe its reasonable to expect others' accuracy to improve both before and during the rate period, as well.

You've requested us to address certain questions related to persistence forecasting or accuracy. I've kind of moved your questions into the various sections in talking about that. But at the beginning of that, you started by saying that -- this isn't a question. It was a statement. It appears that there are significant number of curtailments associated with 30-minute persistence. And I guess we would just start out by saying that we don't agree that there's a significant number of curtailments associated with 30-minute persistence.

Again, as referenced by Mr. Hall in BPA/WIT presentation that was made on January 23rd, the projections, at least at that time, were that curtailments associated with 30-minute persistence are expected to be less than two hours per month on average.

So this gets to the next question, which is whether the wind generators and receiving balancing authorities are prepared to accept the number of curtailments that are expected to occur if BPA holds reserves at the 30-minute level. And the answer for Iberdrola is yes.

In our view, it is more economic and, therefore, preferable to pay a 30-minute rate and accept the associated exposure to curtailments, which again, we do not believe will be significant, than to pay substantially higher wind integration rate. It will allow Bonneville to hold reserves that aren't really needed.

And further, we expect we will be scheduling at 30 minutes or better for the rate period, so for our company in particular, we do not view our exposure curtailment to be very high.

You also asked about DSO 216. And I want to just emphasize that Iberdrola recognizes and fully respects Bonneville's obligation to maintain power system reliability, and we support the goal of limiting generation to schedule as necessary to maintain system reliability standards.

It's our view that some of the concerns that have surrounded DSO 216 have surfaced because Bonneville requested -- it was a little bit of a process glitch in that you were requesting parties to agree or begin to show agreement to the DSO conditions prior to the conditions being finalized and in many cases before parties had seen them. And I think, obviously, parties are almost always going to be unwilling to agree to conditions that they haven't seen yet, and because that process started that way, it's built up a great deal, I think, of suspicion about what's behind that and what is going on.

I think you can minimize the possibility of challenges to the DSO by ensuring that development of the DSO and modifications occur in a transparent and collaborative process. Further, Iberdrola is unlikely to challenge the DSO if there's transparency and collaboration in the process to create and modify it, as well as a commitment from Bonneville to provide after-the-fact transparency regarding the cause of any event that required implementation of the DSO.

And with regard to Bonneville's reliance on the DSO as a factor in determining scheduling accuracy levels, we do believe this is an important tool for you to use to maintain system reliability and it should factor into your decision regarding scheduling accuracy level for the rate.

However, the DSO's mechanism that's going to allow you to ensure your reliability is not at risk no matter what persistence level you select. We would prefer that you go in the direction of the lower scheduling accuracy and use the DSO because the DSO is going to drive better scheduling behavior. People don't want to be curtailed. The better they schedule, the less likely they're going to have a problem that requires curtailment.

But if the costs are loaded into the rate, there's nothing they can do. The rate isn't going to change. It's not going to change based on your performance. You're going to be stuck paying those costs no matter how you perform. The incentive provides you get better. It doesn't reward you for doing well.

MR. ROACH: Lara, so there's a certain feel to this of are we going to get there on the 30 minutes? What would Iberdrola's position be if Bonneville were to basically adopt a stepped rate, a stepped rate in the fashion of -- we can do this in a number ever ways, but one way might be to set it initially at 30 minutes, and then if parties don't meet that standard, then the second year increase it automatically.

MS. SKIDMORE: Increase it for everybody or increase it for the parties who are weren't making it?

MR. ROACH: Everybody.

MS. SKIDMORE: The way I just said it, I think, is a proposal that might be very attractive to us. It sounds similar to some of the ideas that we had been trying to advance earlier. Although, I think in Iberdrola's case we would not want to be penalized for others not reaching it and would like to see a rate developed where if you set it at 30 and people are making it, they should be able to stay at that and not be penalized for what others are doing.

But I don't think there would be opposition to one that if you set everyone out in the first place and moved them later if they're not. Or vice-versa, the idea that parties might select one of the -- you could have two different persistence levels and let parties select and have the option to move out of it or be forceably moved out of if you're not meeting the one that you selected.

Absent Bonneville adopting changes to the assumptions and methodologies that would result in a rate that is no more than 50 percent above the current rate, and I want to be clear here, we're advocating for changes in the scaling methodology and the persistence level because we think that's important. We think that's right. The issue with the level of the rate and what we're going to do with respect to self-supply has to do with Iberdrola's own company economics, and when I put out this 50 percent level, I'm not saying changes in scaling should get you to that number. That's just our number. And I think you guys were hoping for us to give you a signal, and so we're giving a pretty clear one. But that's what it is just for our company.

If you make the changes and the rate goes down but it doesn't get there, we still think you should make them, because I think scaling should be accurate and I think the persistence level should be set at the proper level.

The company is still going to move on self-supply because that's still more economic for us. But we don't want you to misunderstand and think that we won't do that if the rate level doesn't get to the right level because that's what we intend to do. But we also want to say that we still think you should do those things because they're the right things to do, whatever impact that has on the rate levels. I want to make that point clear, because I'm not sure if that always come through in our arguments about our issues with the rate and our statements about what we may or may not do if certain things do or do not happen.

In any event, we think it's really important for Bonneville to enable a mechanism that would allow us to self-supply, and one or more components of the reserve requirement, obviously, you can't really self-supply the entire reserve requirement, but one or more of the components is an important concept and there needs to be a some sort of mechanism in the rate that will recognize that, or obviously there is no incentive to do it if you don't have some credit for it.

We're very encouraged by the outcome of our recent regional discussion on May 29th where self-supply was identified as a top priority for the entire region. In order to make this work, we need to have a proper adjustment mechanism in the rate. And there's two different ways we are suggesting. This doesn't mean you guys can't think of a better one. You're probably a lot better at developing your own rates and rate mechanisms than we are, but the two we are suggesting is either separate out the WI-10 rate components and allow an exception for components that a customer is self-supplying, or create a crediting mechanism for components that a customer is self-supplying. And the adjustment mechanism should be available to customers at the time they implement self-supply so that it's not something that comes back with some long lag time involved.

I believe the Administrator has asked parties to respond to some specific questions regarding self-supply, as well. One of those was the potential variability due to self-supply, revenue variability. And again, Iberdrola believes the rates should include adjustments that reflect reductions in the reserve requirement, and while we think it would be preferable to include something in the current rate case to deal with revenue variability, if Bonneville is unable to accomplish this in the time that is remaining, an expedited 7(i) could also be conducted within the rate period to deal with those issues.

You asked wind generators how sensitive the decision to self-supply is to the integration of the wind, and it's very sensitive to the level of the rate. As we indicated in our brief, we have determined that if the final rate increases more than 50 percent over the current rate, it will be more economic for Iberdrola to either self-supply or to form our own balancing authority area.

I'd like to briefly mention the persistent deviation penalty. There were a number of changes made to this from the initial proposal, and some of the changes we think are improvements over the initial proposal and we think that the added clarity is very helpful.

Our issue at this point is just going to the level of the penalty. We think that we should not increase it to 150 percent of market. We think that's too high. And it's important that you have this rate in place at 125 percent and you haven't applied it and the statement -- I understand that the reasons you haven't applied it have to do with, I guess, the way that it's written. It doesn't have to do with the level. And in suggesting that the 125 is not high enough to discourage the behavior you're seeking to discourage, I think it's really hard to show that when you haven't ever applied it. That is a very significant penalty level.

And in the industry, particularly when you're taking out the intentional nature of this penalty and making it more of a penalty that applies when behavior may not be intentional at all, to raise it to such an extreme level, which I think that penalty level would be considered to be very -- a very high penalty level at the FERC, I think you really would need to demonstrate that you have something in place. You've been applying it. It is not changing people's behavior. You need their behavior to change and that's why it needs to go up that high.

While we don't think it's consistent with current FERC policy and that you'll have a very difficult time showing that you're demonstrating you have a need to this change at least in the penalty level, so we would encourage you to keep it at 125.

MR. ROACH: Based on what you just said, I'll ask you, would it be reasonable to step that rate, as well?

MS. SKIDMORE: Step it to 150 if people are not --

MR. ROACH: Yeah.

MS. SKIDMORE: I wouldn't say it would be unreasonable to do that. I think in order for you to get that rate approved, at least on a reciprocity basis at FERC, you're going to have to demonstrate a need for it, so you're going to have to show it. If it was stepped, part of the approval of the step should be premised on a showing that the 125 wasn't working.

MR. ROACH: Thanks.

MS. SKIDMORE: So in conclusion, again, we appreciate the efforts of your staff and management to work with us. Despite these efforts, it looks like the proposed rate is still going to be too high in our view, and unless there's a substantial change to the final rate level from what we've seen in your direct and rebuttal cases, we expect it's going to be more economic for Iberdrola to go to a self-supply option where we are self-supplying one or more components of the wind integration rate.

We look forward to continuing to work with you on a way to enable this. It's very important that there be a rate mechanism in place to allow us to do this. Hopefully, this is an option that can be beneficial because it will reduce the burden on the BPA system, as well. So I think there should be an incentive for an inclusion of that mechanism in the final ROD for everyone.

Thank you. Do you have any other questions?

MR. NORMAN: I have a couple. I want to make sure I understand how you're thinking about the penalties under the DSOs. When you say curtailment, are you referring both to cutting a schedule when the wind is under-generating and feathering back when it's over-generating off the schedule?

MS. SKIDMORE: I was talking about orders that limit you to your schedule.

MR. NORMAN: So feathering back the schedule. So what about cutting the schedule if you're under-generating?

MS. SKIDMORE: Well, I think that would be included.

MR. NORMAN: Okay. What's your understanding of how much difference there would be in the rate between 45-minute persistence and 30-minute persistence?

MS. SKIDMORE: We don't have specific numbers. We don't know. You guys haven't put out what the number would be. We realize there's been changes in adjustment and you said you're going to do some things differently, so it's not the numbers we've seen so far. We tried to guesstimate, but without all the data, I don't know. Between 30 and 45, I think the difference on a dollar basis is almost $3 per megawatt hour. That's my understanding, but...

MR. NORMAN: Just trying to understand what you're saying. We prefer to have a higher risk of curtailment than pay the higher rate basically is what you're saying. When you say that your understanding of how much higher the rate would be is in that neighborhood, about $3?

MS. SKIDMORE: I think that's correct. What I would say is that this is probably a very entity-specific calculus. For us, and I didn't do the numbers so I hesitate to represent the numbers in any way, except I know when Iberdrola looked at them in their analysis, when they look at how much do -- first of all, they have a lot of confidence in their scheduling abilities, so they're assuming they're going to be on most of the time. So there's not -- there's confidence in that.

But when you look at the costs for what the expected curtailments were, at least based on your WIT presentation, I think that's what we've been using, and you compare that to the increase in the rate for holding those reserves all of the time, it appears to be much cheaper to face that exposure.

MR. NORMAN: Thanks.

ADMINISTRATOR WRIGHT: I can't help but wonder since the first three or so minutes of your testimony is based on the rate you think we're headed towards, what rate do you think we're headed towards?

MS. SKIDMORE: I think you're headed for a rate that's higher than a dollar. We don't want you to be, though, but that's the vibes we're getting.

ADMINISTRATOR WRIGHT: I still am struggling with your response to the question that was asked earlier that somehow this rate will push developers to other regions. I just -- if load needs to be met and there are renewable portfolio standards in all the states along the West Coast, what other regions are wind developers going to go to?

MS. SKIDMORE: There's other regions. There's also a formation of a separate -- I think what most would agree is a relatively undesirable approach is formation of a separate balancing authority area as well, so if you're in the region, you're shielding yourself from the costs.

ADMINISTRATOR WRIGHT: That's a different question. The wind would still be developed in that scenario.

This issue of the wind won't be developed if we adopt this rate is one that I really struggle with. I cannot figure out the economics that drives that statement. So help me with the -- what are --

MS. SKIDMORE: It's my understanding, it will be pushed out of the Pacific Northwest and out of the Bonneville balancing authority area. They'll be located elsewhere.

ADMINISTRATOR WRIGHT: In that case, they would have to pay large new transmission costs, large new transmission costs, and presumably those local areas that are now hosting the wind would choose not to charge for integration services.

MS. SKIDMORE: Potentially, or charge it in a different way, or I think in a lot of case, they charge lower costs.

ADMINISTRATOR WRIGHT: It would have to be substantially lower to offset the new transmission costs, really substantially lower.

MS. SKIDMORE: I haven't run the analysis, but I have been informed fairly consistently that the economics would push it there at that level.

ADMINISTRATOR WRIGHT: To be honest, that's what I'm worried about, the analysis hasn't been run. These are statements but not backed up.

MR. SILVERSTEIN: Actually, further clarification, please. Is your expectation that wind for delivery into the Northwest would be located in other geographic regions because of the lower charge and then delivered, or basically the wind would be developed in another region for sale into that region and the Northwest would no longer be a recipient? Two very different scenarios.

MS. SKIDMORE: Right. I would say both would likely occur. You're still going to need resources here, so I imagine some will come here.

MR. SILVERSTEIN: I think if it's the first case, if they're located in another geographic area for sale into the Northwest, then there are significant transmission costs and losses associated with moving that. And you believe that the potential rate increase as you calculate will be enough to incur those additional transmission and losses?

MS. SKIDMORE: It seems to me it's going to depend on what the individual entity is, what their other resources are, what their existing transmission holdings may or may not be. It would seem to me it's dependent on the circumstances. But it seems like this number is regarded as high.

ADMINISTRATOR WRIGHT: I'm trying to understand your position with respect to whether the persistent deviation charge is, in your perspective, the same as Deviation Band 3 and, therefore, will be rejected by FERC.

MS. SKIDMORE: Well, it's not identical to Deviation Band 3, but what I think FERC has said is that for intermittent resources in particular -- as a general statement for all resources, I think, FERC views the step structure within the energy and generation imbalance rates as being the mechanism to send the market signals to expect the right behavior.

They're generally not a fan of separate penalties or establishment of separate penalties. And I think they created that structure and reaffirmed it in 890 because that should, I think, they view it in almost all cases, it invites the right behavior and sends the right price signals.

They have allowed additional penalties when someone can show that that's not working, and so the question is just have we shown that in this case. We haven't even applied it, so I don't think we can show it.

ADMINISTRATOR WRIGHT: So I think what I heard you say is that you're okay with keeping it at 125 percent, but you are opposing there being specific criteria for persistent deviation because there hasn't been evidence displayed that, in fact, this is a problem. Or are you okay with establishing persistent deviation charge at four hours or some other -- actually, this is a two-part question -- at four hours or being at some other criteria?

MS. SKIDMORE: Well, this charge has changed an awful lot from the beginning, so our direct testimony was very highly critical of what your initial proposal was is all that I'm going to say.

At this point, we have seen a lot of movement on that charge, so I wouldn't reiterate all of the same issues we were taking at all. Iberdrola is fine with the four hours. For the most part, the changes that you've made to clarify we think are helpful. P.

We'd like there to be more clarity in when you apply the charge. We would like it not to apply to wind generators because we think, in part, and just a lot of the rhetoric, the language in the testimony seems to says to us that you're really trying to get to wind scheduling at this. And we understand that you want us to schedule better, and we feel like we're getting that signal. We get it from the DSO. We're getting it at the level from this rate, which varies tremendously based on the scheduling assumption. And we would prefer to have that signal come to us directly in one place rather than having it coming up all over the place in a number of different charges.

And it seems this charge, for me, there were intentional deviation penalties that have been approved by the Commission. They're out there. For the most part, this is supposed to be targeting some pretty bad behavior. Like I say, that in most cases they view the imbalance penalty, the step penalty rate for the imbalance to be sufficient.

So putting this in, it's supposed to be for bad actors. Now, we've morphed it. We've changed the name. We've softened it. We're proposing to increase it. But what it's getting at is we want you guys to schedule better, and we would prefer to have that signal not be scattered all around and not sort of hidden under a charge that looks like it was originally doing one thing and now it's kind of being used to do something else. That was sort of the line, that was my criticism, I guess, of it.

But ultimately at this point, the language changes we think are better than where we started. We can live with them. We just want the penalty level not to go to 150. We think that's very excessive.

ADMINISTRATOR WRIGHT: From what I understand, you just said you're okay with four hour. You'd like the 150 to go to 125 percent. You'd like more clarity about the waiver language.

MS. SKIDMORE: Yes.

ADMINISTRATOR WRIGHT: When it applies and when it doesn't.

MS. SKIDMORE: Yes. And would hope that -- we had tried to -- I think we suggested in our direct testimony that there be some specific procedures around the waiver, and that's something that I think the Commission has talked about in 890 as well, when you are going to have penalty waivers, that you explain and how you will do that. We were hoping that customers would have an opportunity before the charge was applied to demonstrate that they had taken mitigating behavior.

I think the idea of any kind of a formal process or spelled-out process for doing that was rejected sort of by both sides of the house, I believe, in the rebuttal testimony. But my sense is still that -- I'm not sure why you wouldn't want to do that. It is a penalty charge. Obviously, if somebody is having a lot of trouble with this charge and they're incurring it a lot, there should be some kind of discussions about what's going on. And if it really is triggering when people are doing their best to schedule, then there may be different problems we need to figure out.

But it just seems to me hitting people with a high penalty, unless their behavior can be corrected, this is coming back to the point, if it's not behavior that you're doing on purpose, you can't change it. You can't correct it to avoid the charge. So it needs to be directed at the right thing.

I think with this one, we probably have to wait and see when and how it gets applied. We don't have any track record of how you're going to do it because you haven't been doing it.

They may raise other issues once it gets going. Again, my client is pretty confident they're going to schedule well so they're not fearing that this is going to be imposed on them very much, if ever, because they would assume that their accuracy is going to be such that this isn't an issue for them.

But it is establishing a precedent, and I think on principle, penalty charges at those high levels should not be in place without a demonstration of the need.

MR. ROACH: If I can interject, so what little bit we heard today and in the testimony, I would say the record indicates that some people's best is not all people's best. And so when you articulate a standard of a company doing its best, well, that's a standard that may allow those who don't rise to the best that Iberdrola exhibits, the penalty doesn't apply to them because they're doing their best.

Don't you think that it should be something other than doing your best, some more objective criteria?

MS. SKIDMORE: As far as when the waiver would apply?

MR. ROACH: Yes.

MS. SKIDMORE: Well, again, I think the proposal we have been suggesting in the direct testimony involved looking at what specifically happened, because I think these instances -- if somebody is just being sloppy in their -- and they're scheduling all the time, that's probably not all that hard to see. If there's an unusual wind event and somebody is trying to change the ramp and they're just not getting there, they're doing their best.

What you don't want to incentivize is people deliberately scheduling poorly in the opposite direction to avoid the penalty, because frankly, that is something that you could do. That would be intentional bad behavior and that would aggravate your problem on the system and it wouldn't trigger the penalty.

So I just think you want it to be incenting the right behavior, and if people are trying to genuinely be accurate, if you're willing to sit down and look at them, well, here's what we saw. Here's what we projected. Here's what we did. Someone is taking reasonable response to what they're seeing in the weather and how they're seeing their units behave, I'm not sure you should be penalizing them 125 or 150 percent of market. I hope you would waive it in that circumstance.

MR. SILVERSTEIN: Let's look at an example. We have a wind ramp that's moving in one direction over a period of time and the scheduling agent for this has not changed its forecast in four hours. Is that bad behavior?

MS. SKIDMORE: If they are seeing -- well --

MR. SILVERSTEIN: They have the data.

MS. SKIDMORE: If they have the data and they have a reason to think the ramp is going to continue and they are not changing it, then that would seem to be bad behavior.

From what I know of it, it can be very fact specific. You may think it's going to blow through in two hours so you missed it because you didn't realize it was happening and you've missed the ramp, but then you have reason to think that it's going to end. Well, you want to be scheduling for what you expect to happen, not because you're trying to avoid penalties by over- or under-scheduling in an opposite direction.

It's my understanding that they can behave differently all the time. And it can be many hours; it can be a few. And in order to catch them and do the right thing, it's going to depend on what that particular wind event is doing.

MR. ROACH: Let's assume two similarly situated wind generators, same circumstance, maybe they're located in the same area, exact situation that you're talking about, Iberdrola, no problem. But the next-door neighbor, no, there is a problem.

Would you say in that circumstance that, even in that circumstance, that the next-door neighbor should be granted a waiver?

MS. SKIDMORE: I would say that it would depend on what they did and what they knew and what they were doing.

If Iberdrola caught the ramp and scheduled just fine, then there was obviously a data or a skill set or both that were available to give you the ability to do that. Maybe they just were good guessers. But I'm guessing they may have, in that case, had data or people that the others didn't have.

Well, what did they have? What did they know? Were they using the wind site monitoring data that was available, or were they just ignoring it and letting it go and go and go?

MR. ROACH: Let's alter that a little bit. Isn't this about incenting people to rise to a level of care that you're saying that Iberdrola is taking, which is to say why shouldn't that neighboring utility or neighboring generator acquire the resources and the manpower to be able to exercise the same degree of care that Iberdrola exercises?

MS. SKIDMORE: Well, I think it's our view that they should. And we would hope everyone is incentivized to do that. It's probably going to happen on different schedules.

I guess my issue would be how do you do that? Are you doing it in a number of places right not in this rate case? You're doing it with the DSO. You're doing it with the wind integration charge and assumptions on scheduling accuracy that go into that. You're doing it with the persistent deviation charge. And there's exposure to imbalance penalties. There's a variety of things that happen to you if you don't choose to take action to schedule better.

So, yeah, I think everyone should schedule better. How many times should they pay for it? How many times should they get penalized for it? I guess that we may not agree on. And then I also believe that as far as the penalty charge goes, it should be very fact specific to that event.

ADMINISTRATOR WRIGHT: More of a comment than a statement, if I translate your dollar per kilowatt month and the dollars per megawatthour, it's probably somewhere between three and $4 per megawatthour. And I'll come back to my initial comment and say effectively --

MS. SKIDMORE: I think it's 4.50.

ADMINISTRATOR WRIGHT: That's actually going to make my point stronger. Thank you.

MS. SKIDMORE: Glad to help.

ADMINISTRATOR WRIGHT: So effectively I think what you're saying is that the differential between that rate and the rate we adopt will be enough to cause people to choose to not to develop renewable resources in the Northwest and go some place else. Now, if you thought we were going toward the $12, the original initial proposal, even that would be a stretch, I think, but there's been enough evidence in this case to suggest that the rate is going to be lower than the initial proposal.

I would just suggest that that seems to be -- based on my knowledge of the economics of project development, that strikes me as a real stretch, that little of a difference. You can't avoid the charge. It's going to cost 4.50 by your analysis to self-supply. So it's not our rate versus their own. It's our rate minus what the alternative is. So just seems to me a stretch to get to, well, that will cause renewable resource developers to go some place else.

MS. SKIDMORE: Again, I think the calculus is going to be different in the case of each entity, and we're just sharing with you what ours is.

ADMINISTRATOR WRIGHT: Thank you.

MS. SKIDMORE: Thanks, everyone.

HEARING OFFICER PETRILLO: Thank you, Ms. Skidmore.

M-S-R.

MS. FISHER: Hello, my name is Ann Fisher and I'm here on behalf of M-S-R.

As a preliminary matter, I hope you get another glass, Your Honor, because I may start coughing and may need it myself.

It's nice to see you gentlemen. The first time I saw Mr. Armstrong, we were over there in the Rates Hearing Room on the top of the Lloyd Center, and at every break, we would come out and hear Amazing Grace. I always thought that had a particular aspect of the rate case, and that cases here have a lot of amazing grace in them: a combination of policy, statute, trying to weigh issues that are often difficult to weigh.

As a preliminary, I'm not going to discuss how to calculate reserves. I'll give you a little more about M-S-R in a moment. I'm not going to -- I'm trying to avoid reiterating the things that the Northwest Wind Group said and Iberdrola said.

Notwithstanding that, I would tell you that for the most part, M-S-R agrees with those statements made, except that we're not prepared to say unequivocally that there is a cost for integrating wind that isn't already being collected.

And in answer to a question that Mr. Wright raised, since we are a buyer of wind, at $12 it would represent a 3 percent -- that price alone, that extra surcharge alone, would represent a 3 percent rate increase for M-S-R customers. So it has significant impact.

M-S-R Power Agency is comprised of Modesto Irrigation District, Cities of Santa Clara and Redding. They buy the total metered output of Big Horn, just under 200 megawatts. That makes it one of the largest, if not the largest, purchaser of wind in the region. Redding itself also owns significant rights on the California/Oregon transmission line.

We're not here just for Big Horn and the costs that M-S-R will have to pay if this rate is instituted at the levels in the initial proposal, or for that matter, anything more than a dollar would be problematic. But we are anticipating greater cooperation and coordination of activities between Northern California and the Northwest region. That's coming.

In the future, we can expect that solar will be coming this way. Wind will be going that way. And perhaps wind will stay in the region and solar will be brought in. We want to make sure that what happens here takes the right approach and sets up the future in a way that works for everyone, not just this rate period, but for the next ten rate periods.

We see that some of the major purchasers of those renewable resources will be public preference customers, both in California and as M-S-R is comprised of and in the Northwest. And so this is a bigger issue than just wind versus publics. This is how do we best accommodate wind as a renewable resource in the Northwest and in the West Coast.

I'm here to tell you three things, and before I get started, I should ask if you have any questions. I don't want to debate with Randy about whether something is duly or unduly or just moderately discriminatory. Those are legal analyses that probably don't foster the discussion that I really would like to have, which is one on how do we move forward from here.

MR. ROACH: So I do have a question, based on what you said.

MS. FISHER: You couldn't resist, could you, Randy?

MR. ROACH: So you said $12 would be a 3 percent rate increase. 3 percent rate increase on what? On the total that you're paying?

MS. FISHER: No. Rate increase to M-S-R customers.

You asked questions and Mr. Wright asked questions of Mr. Hall. I leaned over and asked Mr. Arthur, who is here and my client representative, and said: Okay. Can you answer this question? No, that's confidential. Can you answer this question? No, that's confidential. But I can answer the next question which was, if you have to pay the entire amount yourself, meaning M-S-R, and there's no accommodation made as between the project developer and M-S-R, what kind of rate impact will it have on your customers, your regional customers, your customers of a preference load? Because we are preference customers in California, even though we're not Northwest preference customers. And that would be a 3 percent rate increase.

MR. ROACH: Like the last attorney, I oftentimes am reluctant to do the math, but by my math,

$12 is 3 percent of 400. So what you're saying is that a charge to your customers is $400?

MS. FISHER: Randy, like you, I don't do numbers. I gave you my authority and that's all I can do today.

MR. ROACH: All right. Thank you.

MS. FISHER: I'm here to see that we ought not to be here. It's wrong on three counts. It's wrong because the approach taken is, I think, subject to debate with Randy, against FERC rule. We shouldn't be here because it's bad policy. And we shouldn't be here because it's premature. So that's all I'm going to tell you.

By way of background, Bonneville currently anticipates approximately 3,000 megawatts of installed wind during this rate period. That's kind of a fudge number because there is some testimony that there may be some additional adjustment within the final proposal reflecting additional wind reductions, and there is a discussion about what Puget Sound Energy, Iberdrola and other wind projects may be doing, which would reduce the amount of wind.

Beginning in this rate case -- in the beginning of this rate case, it appeared that the reason for the rate case was that there was a humungous, perhaps as much as 20 percent rate increase that the public preference customers were going to face. That would be pretty dire for this region, as you all know.

As part of trying to find ways to make some additional revenue, it also appears that every nook and cranny was searched, every rock overturned, and suddenly we came up with a wind integration charge that has some very interesting aspects, different than you might find if you went to - I don't know - Portland General & Electric down there -- not Portland General. PG&E, Pacific General & Electric.

What this does is set up a series of rates or charges that effect wind development or wind projects specifically. So we have a lot of verbiage, we've discussed that already at length this morning, about the persistent deviation charge. And the testimony is replete with what I'm going to call is straight-out anger at wind developers and, by God, that persistent deviation charge should apply.

Then we have a great deal of testimony in this case about generation imbalance, and it kind of goes all over the map, discussing it in terms of cost, causation, imbedded costs, but not variable costs, and maybe it covers this and maybe it's not.

Generation imbalance has been described

variously as settling the energy used within the hour to capturing a variety of ancillary services applied, all within the hour, to generation. That sounds suspiciously like the charges -- no, the description of components of the wind integration charge.

The wind integration charge apparently reflects a cost of providing the same ancillary services, but that cost is not calculated as a cost. It's calculated through various computer simulation models that set up a proxy. And what is that proxy based on? Outside the hour variations. Essentially it recovers and is intended to recover the lost secondary sales. It does that through the 120-hour band width, if you will, of impacted power sales. It does not - and I'm searching for the specific quote - it does not cover instantaneous capacity, energy and uses of the system that use the combination -- and uses of the system that use the combination of capacity, energy and flexibility within the hour. Well, if it doesn't cover the instantaneous capacity, energy and uses of the system within the hour, what does it do?

Well, we have lots of models. They're just models. They're based on no empirical evidence. They're based on best analytical work. But, you know, remind you, garbage in/garbage out. Put away the assumptions. What are the assumptions behind each of those models? How do they fit together? How is it one set of models we can look at minute, ten minute, hourly data, and the next set of models we can't do something because we don't have minute, ten minute, hourly data?

I put your testimony down for a week or so and came back to read it for this presentation. I pro temmed for 11 years as a judge in Multnomah County, and what I saw repeatedly is that attorneys and their clients often became too enamored with what they were doing and didn't understand the bigger picture.

When you have as little space as a judge does, or as an outsider does, you see that there are conflicting studies, if you were to put them all together and a lot of unknowns. Mr. Wright, you said it. We're all learning this stuff now.

So the third thing I want to tell you -- the second thing I want to tell you is that it's bad policy. I'll go into that.

But the third thing I want to tell you and I want to tell you forcefully, it's premature to be here. There's too much we haven't got, too many analyses that go part of the way but not go all the way. It's too soon to set precedence on things that we don't understand fully.

Now, back to FERC. I think the generation imbalance charge under FERC Rule 888, 890, 206(b), 661 all require exactly the same charges or exactly the same costs be covered in the generation imbalance charge. I won't argue with you that maybe your generation imbalance charge isn't appropriately recovering all of your costs, and maybe that's some place that you ought to be looking at in the future.

MR. ROACH: Ann, let me interject. And I want to hook up what you just said just a tad bit ago with what Iberdrola was saying.

Iberdrola was saying we are making decisions and will make decisions based upon what we are charged, and I can well envision and your position seems to be that we should just sit back for another period of time and in terms of the charges that are at issue here, not charge anything, that Iberdrola would then have to make a decision without the information as to what Bonneville would charge.

And I can well envision that, let's say, that in the face of that two years from now, Bonneville came back and, based upon all their experience, charged exactly what has been proposed in this case, that they'd be screaming bloody murder that, wait a second. We sort of like this 400 rate increase that people are yelling about or 350. And they'll say, wait a second. We decided here based upon what you had done and the rate case settlement before and we didn't have fair notice, et cetera, et cetera. How is that good public policy?

MS. FISHER: You're asking a really different question than what I would call public policy, but I'll answer it.

I think this case, when I say we're premature, this is a case that you ought to settle. M-S-R tried to advance that several times, part of which was stricken from its testimony. And you might settle it at the dollar that Ms. Skidmore suggested. I don't know what the right amount is because I don't know what people would agree to.

And then I think you need to make a commitment that's different than the commitment you made in 2009, and that commitment would be that for the next rate case, whether that's 2011 or 2012 - you could conceivably have another one within a year - that the wind integration team be part of the rate case. Because one of the problems that has been consistent throughout this process is the wind integration team is over here busting their tail trying to figure this stuff out, working against a deadline that is in humane. And the rate case is over here with a revenue requirement based on lost opportunity costs and a need to supplement PF rates and some other concerns out there, and never the twain will meet.

We put in some testimony. It was a big concession that they would be allowed to have some testimony from the WIT team talking about some of the things that were going on. But what the testimony didn't say is we've got it knocked. We've got it figured out. It's not there. It's in transition.

Now, the second part of your question is how am I going to keep Iberdrola from raising bloody murder in a year? Honest to God, I've been doing this stuff for over 20 years. I guess that makes me something of an old-timer. But I've got to tell you, you want to know how many people in this room I have seen over the last 20 years? It's not just you guys that I saw 20 years ago. Look around. These people are raising holy heck often. That is the nature of the rate case. And I can no more guarantee that Iberdrola won't in the future than I can guarantee that CUB won't raise the same issues that it did in 2009 in this rate case. It's just the nature of the game.

The important part is that we find a way to accommodate some concerns that Bonneville legitimately has and also a way to figure out what the right answer is.

It's probably not worthwhile to say anything more about FERC, so I'll skip that part in the effort to be short.

The second part is public policy, as I view it. I think public policy is the job description that Mr. Wright has. How in the world does one balance public preference rights with the ever-increasing demands on the federal based system? It was not all that long ago when we thought fish would be a small demand and would probably go away. It would get fixed easily. And look where it's gone.

There is a sense among preference customers that all of the secondary revenues are available. All of them that might be, possibly could be forecasted or maybe imagined, despite knowing from 2009 that we can't really tell those numbers, should go to offset preference rates. And that in itself, you can write volumes in legal briefs.

So I'm not suggesting that it's a legal answer, although I think the legalities are against you. I think the answer is how are we going to make it work for the people that you care most about. The public preference customers, certainly. Wind development, as opposed to developers, just as certainly.

And then you've got all those other obligations. Coordination. The return on the treaty rights. And so in doing whatever you do, you have to put all those together.

Now, we don't have -- there's no place in the testimony, in actual verifiable, ascertainable, quantifiable costs associated with integrating wind. Intuitively we know there must be something as vast as the hydro system is, it's not so vast as to take wind without any kind of limitation. Okay. Put in a marker. All your methodologies, all your simulations are only proxies anyway. Pick a marker that we can all live with.

The 400 percent rate increase that you quibbled over, Randy, that's not a rate increase based on a precedent. That's a rate impact. People will see a price 400 percent greater than it is now, if you stayed with the initial approach. If you picked another number, obviously that would be much, hopefully, less.

I think that's your job. That's your job to figure out how to get both of those in the door, and both of those in the door in a way that everybody can live with.

If you want me to argue law, I can argue law. If you want me to argue analyses, I can tell you about how pathetic it is to use a methodology in the absence of actual verifiable data. And I can tell you there are a lot of wind developers in the room that will help give you that.

So public policy means you've got to do it all and you've got to do it to the best of your ability, and that means you can't price people out.

And I know, Mr. Wright, you don't think people will go away or find other alternatives, but you have to consider that they might. It's like having income taxes and unemployment. The greater the unemployment, the lower the money that actually comes in in income tax. If you push out some developers, you can just put a number, some developers, you're going to have reduced revenues overall. You're going to have reduced revenues for your transmission. You want to assume that all of this stuff will be in the Northwest, but it might be in other balancing authorities. It might be in other kinds of trade sales. So keep in mind that there's a greater impact.

We've already talked about that we've got the loss of secondary sales. We talk about that a lot in our briefs, and I think you see it in the other wind people briefs.

I think it's, first, never good to use one rate class to subsidize others. You're going to hear that again in other DSI questions.

Two, even before Obama, if you just looked at FERC in the past administration, we know that wind has a bit of priority. The bold way, the whole tiered structure adopted Bonneville's tiered structure, mind you, in a case where, for the life of me, I couldn't get a methane plant in there in the right place as an exception, has supported wind. The emphasis on renewables will continue, and so you need to figure out what to do.

One of the things that you asked earlier was about additional wind farms or wind projects. I know that makes PGE very irritated when I say wind farms. And a question you have to deal with is the socialization of new projects, because right now what you want to do is charge everybody, everybody the same when FERC tells you if you've got new projects that you can't actually accommodate, they have to pay an incremental cost. It's not just the incremental cost for transmission. It's the incremental cost of buying the reserves, if you will. It's another component to be considered.

So where should we go from here? And the answer, I believe and M-S-R believes, is we need to settle the case or set it at a rate, the wind integration charge at a rate that the wind developers can live with, public power can accept, albeit, I'm sure, unwillingly.

In figuring that out, you need to look at both the revenue requirement and the reserve calculation. It isn't enough to say, well, we'll do a 30-minute persistence if you have the same revenue requirement, because what that means is that each reserve itself carries a bigger cost. So you have to look at both of those things.

We need to continue to have the WIT team work and work hard at finding out the real costs and where to put them. We need to figure out how tiered rates are going to fit in. You can count the number of cases that we actually dealt with the cost of capacity on one hand, maybe on one finger, and yet capacity is a component of this. And historically, outside of those few cases, capacity has been recovered in sort of a strained allocation through energy. That's going to change with tiered rates and that's going to impact things and may have come up with a different price.

We need to consider why we can only look at load -- we can easily look at load forecasts in terms of ten minute past, 30 minute past, 50 minute past, but we're not willing to do the same forecast for wind using those same data points, which would radically change how much reserves would be needed.

A big problem for Bonneville and part of the reason you can't do any of these things right now is that your AGC is not complete and it needs to be complete. You're going to have to do it under the NERC standards and it would make a radical difference to the amount of reserves required.

We need to do dynamic scheduling or at least facilitate it. We need to investigate self-supply so that you understand the impacts of it on your system and third-party supply and how much costs.

Again, as you said, Mr. Wright, we're all learning this stuff and we need some additional time to complete it. Don't let the schedule of this rate case drive you into poor decisions.

And other than Randy, does anybody have any questions?

ADMINISTRATOR WRIGHT: I want to clarify two things that you said because I think they're wrong, and so I want you to know.

First, I think you misinterpreted my earlier comments with respect to whether renewable resource development will occur on the Bonneville system. The issue at hand I think with the testimony was whether this rate will discourage renewable resource development overall. It's the broad public policy question, the national question that's out there. I'm having a hard time from seeing this testimony is understanding how that would occur.

I'm really not that worried about whether renewable resource development occurs on our system or whether they provide the integration services or not. If we were worried about that, we wouldn't be going down the path of developing self-supply options, et cetera. So for me, that's not the critical question.

And I think that gets to what seems to be the basis of your sense of our motivations, which I have to admit really troubled me, and I think displayed a shocking display of lack of historical knowledge about how this rate evolved, that some place along the way we thought we were going to have a 20 percent rate increase for preference customers so we had to invent a wind integration rate in order to charge someone else and not charge the preference customers, which was certainly, I think, the implication in your statement.

MS. FISHER: No. I would say it more directly. I think you developed a series of rates all with the idea that it would supplement revenues.

ADMINISTRATOR WRIGHT: I'm not sure if I see the difference between that and the way I just described it.

So we started working on this years ago with the wind integration steering committee, and we identified that these were significant issues and costs that needed to be addressed. We put together the issue in the 2009 rate case and we did settle that and we said we'll come back with a lot more data. And an awful lot of work has been done to understand this.

MS. FISHER: But you're looking at the other side of it.

ADMINISTRATOR WRIGHT: If you just hang on for a second and let me finish, I'd appreciate it.

To describe this as garbage in/garbage out models I think is really inappropriate, given the amount of effort that's gone into this. Now, do I believe we're done and we understand this completely? No, I do not. I know we have a long ways to go and you raised the question of incremental rates, so incremental rates are a challenge we'll face in the future. At the moment, we believe we haven't met the needs of balancing services, that we don't have to address the incremental rates, fortunately in that regard.

But the characterization of what the motivation of the Agency were are so off base that I feel it's important to clarify the record here and say we are doing the best we can to get this right. A lot of people have worked really hard to do that, and I felt that your comments were denigrating to that work and deserved a response.

MS. FISHER: You know that I think the work of the WIT team has been phenomenal, and we are big supporters of the WIT team. That doesn't get you to using lost opportunity costs as a proxy for the cost. And we can disagree on that.

There's an old saw about that there are some things that reasonable minds may disagree. But the minute you put in a component that is based on lost secondary sales outside of the wind within hour requirements for balancing, you raise that specter. And I'm sorry that if I offended you by that, but I'm not going to be the only one who sees it. And chastising me for that, as you are entitled to do, won't change the public perception.

And what I'm suggesting is that you continue the wind integration team work so that you can actually quantify those costs, not so that you use a proxy that is based on something that raises serious questions.

ADMINISTRATOR WRIGHT: Okay. I'm giving you the last word on that.

MS. FISHER: Reasonable minds may differ. You said you had two points. Did you have another?

ADMINISTRATOR WRIGHT: No, those were both of those. The two points were how we look at the question of whether this rate is impacting renewable resource development broadly across the region versus whether we are trying to provide integration services. And the question of how this rate evolved.

So with that, I've given you the last word.

MS. FISHER: Okay. I wanted to comment on your renewable development within and without the region.

I think that many of us believed that Bonneville was going to be a leader in wind development in this region. Certainly the handouts on various meetings talking about conditional firm transmission or the network over the season have been put in terms of this will help facilitate wind. So seeing you as a potential leader in that narrowed my reflection on what this rate would do within BPA's balancing authority. Broadly across the country, you know, it's hard to tell what is going to be developed where.

Anything else?

ADMINISTRATOR WRIGHT: No.

HEARING OFFICER PETRILLO: Mr. Wright, the next argument was scheduled to 20 minutes. I'm just wondering, we're intending to go a little long, do you want to break for lunch now or would you prefer to hear the next argument?

MR. MURPHY: Paul Murphy. I'm the next one up. I certainly intend to keep my remark well below the 20 minutes for information.

MR. ROACH: If I can make an inquiry on that, I didn't see on the schedule that indicated that Snohomish had a preference for the morning.

HEARING OFFICER PETRILLO: It does say that.

MR. KALLSTROM: We're fine with keeping the schedule as it is.

HEARING OFFICER PETRILLO: We can go forward.

ADMINISTRATOR WRIGHT: I think I'm inclined to go forward.

HEARING OFFICER PETRILLO: Mr. Murphy?

MR. MURPHY: Good morning, gentlemen. My name is Paul Murphy. I'm here on behalf of Cowlitz PUD, and it is my intent to address only those issues that we covered in our main brief. There are other people that are going to be arguing the briefs that we either joined in or the trade associations which we're associated with.

I know that Mr. Roach read at least a portion of my brief. I assume he read all of it because he quoted or paraphrased something at the tail end of it. And from past experience, I'm sure Mr. Wright has done the same. So I'm only going to address two issues.

One deals -- I want to emphasize the importance which my client attaches to it, and the other one is I want to change a position that we took in the brief we filed. And I want to be clear on that.

The issue that I want to address for purposes of emphasis is the issue of stepped rates. Ms. Fisher stated that Bonneville looked under every nook and cranny or looked at every nook and cranny and under every rock trying to keep the rate increase down. I think maybe the implication drawn from that is different than the one I'm suggesting. I believe that Bonneville has looked in every nook and cranny and turned over every rock to keep the costs down, to find new sources of liquidity. And my client very, very, very much appreciates the effort that Bonneville has taken to minimize the rate increases necessary to keep Bonneville to be sound. That will help us; it will help our customers.

But stepped rates will, too. And we very, very strongly urge the Agency to adopt stepped rates. There is a significant difference, at least in the initial testimony, I think maybe some of the costs will have changed, the difference between the FY 2010 and 2011 revenue requirement was $238 million a year. That's 8 percent of the total revenue requirement. That will have a material effect on the health of the consumers in Cowlitz' service territory and we assume in the service territory of others. So we urge Bonneville to not develop rates that are going to pre-collect 2010 for costs that aren't going to be incurred until 2011.

And I realize that that's only about a 4 percent difference in the wholesale rates. But our customers are doing everything they can. They're looking in every nook and cranny, and they very much would like to see stepped rates. They're worried about how they are going to fair in 2010. They have more hope for 2011.

And some utilities took the position that they preferred rate stability for the period to lower rates in the beginning, if the difference wasn't all that great. We put in our brief a proposal which we believe would allow you to accommodate my client's needs and the needs of the other utilities that prefer stability. Publish, adopt stepped rates, and we're not asking you to relook at them or reconsider them as others have, just adopt the stepped rates and publish at the same time what the average rates could have been. And those utilities that prefer rates stable for the two years can use those published average rates to set their own rates for two years. And utilities like my client that would like to do more to help their end-use consumers, can adopt their own stepped rates. So that's the one point.

The other point that I wanted to address is the question of what sort of scheduling accuracy should you base the wind integration rate on. We took the position in our brief and in our testimony that it should be at 45-minute persistence. We have discussed this with some of the other wind developers and we are now persuaded that we are better off if you adopt the 30-minute persistence, adopt the DSO and hold the customers to it as described in the DSO, largely for reasons that have already been hit on by Mr. Hall and Ms. Skidmore.

We think that the DSO will target the incentives to improve directly on each different wind operator, and we believe that that's a better way to separate, to give direct incentives. And we also believe that it will ultimately be cheaper for the wind developers and it will avoid the high cost of reserves for the other customers, as well.

And the reason for that, you were quoting Mr. Hall about how that works out. Well, if there's 720 or

744 hours in a month and a customer is subject to two or four or ten hours of curtailment, there's still -- they're still probably way ahead given that you're looking at $12 for the wind integration rate, even if the total value of the energy was worth ten times that. You could put up with 72 hours worth of curtailments, almost. The economics clearly are in favor of set the reserve requirement based upon a DSO that you are going to enforce and then enforce it. So those are the two points that I wanted to bring up.

Now, I'm more than happy to answer questions about any position we've taken in our brief or otherwise in this proceeding. But those are the two points that I wanted to emphasize this morning.

ADMINISTRATOR WRIGHT: Again, as with Mr. Hall, would you go through the math again for me?

MR. MURPHY: There's 720 hours in a month, in a 30-day month. There's 744 hours in a 31-day month. If the numbers that Mr. Hall said as to the frequency of curtailments is even remotely correct, you get curtailed for two hours, but you avoid $12 per megawatthour for the other 720 or the 718.

MR. SILVERSTEIN: It's not $12 per megawatthour. It's $12 per kilowatt month.

MR. MURPHY: The rate was 268 per kilowatt month, and Mr. Hall says that turns out to be approximately $12 per megawatthour. I believe that was the figure he threw out.

But it's the number of hours. How many hours are you paying the rate versus how many hours are you subject to curtailment. And so the -- it really does make a big difference. And like I said, because the incentive is more focused, it is a much better rate.

It has been suggested this morning that there's some sort of public policy that you should be trying to pursue, and what's right public policy I suppose is very much in the eye of the beholder. My client happens to believe that public policy requires cost-based rates. That's why we took a position contrary to most of the public utilities in this case on the wind integration rates.

We believe that the recommendations made were inconsistent with cost-based rates. We also believed that to the extent you can, if the rates have target incentives, that is better than a rate that just hits everybody the same irrespective of the costs that they're actually imposing. And unfortunately, a dollar per installed kilowatt type of rate doesn't give the right -- doesn't give incentives for individual behavior. It just says whatever your machine is, you pay.

I'm sure Ray can do the math for you. He's pretty good at that.

MR. NORMAN: Paul, Ms. Skidmore said that she based her assessment that it would be better to go to 30-minute persistence and take the risk of curtailments on the assumption that there would be on the order of a $3 megawatt delta between 45-minute and 30-minute persistence in our rates. Is that the point you're thinking?

MR. MURPHY: It's not entirely -- we didn't go through a calculation.

Our view is Bonneville's testimony is abundantly clear that through the DSO, Bonneville can operate within the reserve levels that it sets. Therefore, it seems to me, it is the risk that the wind operators have to take. If you hear the unanimous view from the wind operators, we'd rather have the curtailments than pay the higher rate all the time, then you should accept that. It isn't costing anybody anything to accept that.

Now, I can understand how Bonneville is asking a number of questions, which I think in part were to get on the record the views that the wind operators would take with respect to certain things. I can assure you that Cowlitz won't challenge the DSO if it's adopted as basically described to date. And I can assure you that we will accept the curtailments, and I'm sure they're going to have to do some learning, because I suspect that Cowlitz is probably on the wrong end of the scale in terms of accuracy.

They understand that. They intend to take steps to improve their accuracy. And they believe that something that directly incents operators is a better rate. And the DSO does that, because every time you curtail or reduce the transmission schedules, that will cost them something and that will have the same effect as a rate. And they will change their behavior in response to that.

MR. NORMAN: And back on the separate, what's your reaction to a concept of, say, having a unstepped posted rate but using the flexible PF provisions to step the rate for individual utilities who want the stepped rate?

MR. MURPHY: Well, I'm not exactly sure what you're suggesting. But if what you're suggesting that Bonneville would -- if you're basically saying that you would, in effect, step the rate for individual utilities who wanted a stepped rate, that's the functional equivalent of what we're asking for and we're looking for results as opposed to particular methods, and that would be very acceptable to us.

MR. NORMAN: Thanks.

MR. MURPHY: I did want to answer one other question. The question with respect to the ICAC for the DSIs, which form of ICAC. From our perspective, the ICAC is just a bad idea. That's quite aside from the issue of what you're using it for. These little targeted things for a particular variation, I can well see a situation where you're increasing the ICAC charge at a time when your revenues are coming in for other reasons that you don't have the need for the money. And I don't think that's a good idea.

I think that doing your best forecast and having a CRAC type of thing to deal with your overall revenue situation makes much more sense and not have a whole bunch of targeted ones that might be operating in opposite directions.

ADMINISTRATOR WRIGHT: That's clear.

MR. MURPHY: Are there any other questions? Thank you very much.

HEARING OFFICER PETRILLO: Thank you, Mr. Murphy.

I'd like to inquire of Snohomish if your commitment to the morning is -- still stands?

MR. KALLSTROM: I think lunch would be acceptable.

HEARING OFFICER PETRILLO: Let's break for lunch and reconvene in 45 minutes.

(Recess taken at 12:02 p.m.)

AFTERNOON SESSION

HEARING OFFICER PETRILLO: Next up is Snohomish PUD.

MR. WRIGHT: I just want to let you know, Brian Silverstein had to deal with an operational issue and Paul will be right back.

Go ahead and get started.

MR. KALLSTROM: My name is Jeff Kallstrom. I'm here on behalf of Snohomish County PUD. Good afternoon.

I have several issues to touch upon today, but like Paul, I'm going to keep it as short for you as I can. I know you've read Snohomish's brief, and feel free to ask me any questions on that that you may.

Like Cowlitz, Snohomish also signed on to or supported a couple other briefs, mainly the brief submitted by PPC and the other members of the joint party 11, as well as the brief submitted by the Slice customers. I do not plan on addressing those issues. Others will be addressing those later.

In addition to that four items that we raised in our initial brief, I also want to touch upon a couple others. One is diminishing rate increase and one is the step rates, just kind of give you a preview where I'm going. But to start out, I want to note that this has been a very interesting case for Snohomish staff. This is really the first full rate case that many of the members of the Snohomish staff have participated in in-depth, and through the course of the case, we've learned a great deal.

One of the things we saw is just how much time Bonneville staff puts into these cases and we certainly appreciate the effort and want to acknowledge the effort that staff puts in.

However, as we worked through the case, we saw a few area where we felt that there could be improvement. This is what led to the testimony and the statements in our brief about the rate case process. I want to emphasize to the panel, to the Administrator that our intent is to improve the process. It's not to necessarily undermine the existing process. It's to make it better going forward.

Along those lines, we're very encouraged by staff response to our testimony. It was -- staff could have been hostile, but instead were open, kind of acknowledged that this rate case had a condensed time frame and there were external circumstances that bore on this particular rate case, but expressed a willingness to work with customers to see if there are efficiencies and ways to improve the process going forward.

We very much appreciate that and it's our hope we can have that dialogue as we kind of move forward with these additional processes, particularly ones that don't have the time constraints that we're currently faced with.

In particular, one item I also wanted to note, it's my understanding that Bonneville's -- Bonneville staff is already working on improving the RAM model and improving transparency documentation. That's very encouraging. We're very eager to see how that goes, so I want to encourage and support those efforts and we're looking forward to seeing how that comes out.

The first substantive issue that we touched on in our brief is -- that I want to talk about is the reserve requirement and the availability of reserves in integrated wind resources. This is not my personal area of expertise, but I was asked to hit a couple of high points to let you know about concerns Snohomish has.

The first is, you know, we obviously want our rates set that does not involve a subsidy or a shifting of cost from preference customer -- or from wind developers to preference customers. So it's really the general principle of that whatever rate Bonneville set, it needs to take into account the full suite of uses of the FPS and price those wind integration services appropriately in light of those alternative uses.

The second issue, the second concern we have is as Bonneville provides certain wind integration services, it has an impact on the flexibility inherent in the FPS, and for a Slice customer, like Snohomish, this is a particular concern. It's a concern that's been expressed before this notion of off-the-top obligations.

So we'd like the Administrator to keep that in mind as he moves down the path of trying to integrate wind and constraint, how to price and what the appropriate levels are and that sort of thing.

Another issue raised by Snohomish in the brief is the customer charge. Our brief has our detailed justification as to why we believe the customer charge is appropriate, but I want to elaborate on how Snohomish came to actually propose the charge.

As we were examining Bonneville's initial proposal and evaluating rates and rate components, we were doing so through the lens of cost causation, and this notion that if an entity imposes a cost on the system, they should pay for that cost. And from that analysis and that examination flowed the notion of a customer charge. And that's establishing this idea that some costs are directly proportional to the amount of energy that a customer consumes while other costs are proportional to the number of customers as opposed to energy.

Unfortunately, based on the information we have, that's kind of where our analysis stopped and this is why in our testimony and our brief we were trying to get across that one of the things we want from Bonneville is a further investigation of that to see if this shift, this possible cost shift that we've identified is actually real.

And Bonneville possesses that information, and if it turns out that it is something that's a real shift, then we can pursue it. If it turns out that it's not, then, you know, that ends the inquiry and we have enough information to make that full decision.

The final issue that we addressed in our brief that I want to raise today is the variable IP rate, and it's really a -- well, in this discussion, it's kind of setting aside the notion or the debate about whether Bonneville should or should not serve DSI load. It's really just what rate should that be at.

As we explained in our brief, we don't believe the variable IP rate is consistent with the Congressional directive. And that really stems from the simple fact that the Power Act directs the Administrator to set the rate equitable to preference power rates that preference power customers, public agency customers charge their industrial customers, and then went on to say that that equity is based on a particular formula and then set out that formula in the Act.

Our concern is the variable IP rate doesn't seem to have any real tie to that formula. It's really based on the world price for aluminum with the outside goal that over time it will in some way or another equalize the standard or statutory IP rate.

And so from that end, we see a legal infirmity in adopting the variable IP rate, and so we urge the Administrator not to go that route and stay with the standard IP rate to the extent the Administrator decides to serve the DSI load.

So moving on to the issues that were not in our brief, the first one I want to touch on is managing the rate increase. Again, I want to express appreciation to Bonneville staff for working with customers to try to keep rates low and to respond to the general turmoil that has come over the region in the past several months. Despite the greatly changed conditions, market conditions, new administration, other conditions that have befallen us, BPA was able to hold the line on rates in 2009. Again, that was very good news for the district.

However, the one statement I would make about this is that in addressing future rate increases, Snohomish would like to see Bonneville look beyond risk mitigation. In particular, we want to see Bonneville kind of continue to put pressure on keeping costs as low as possible wherever IS possible and to continue exploring these cost-cutting measures in the middle of the next rate case, not just do a one-time cut rate now and let it go.

Other utilities in the region as well as Snohomish are continuing to look at ways to cut costs now and in the next several years, so we want to encourage Bonneville to do the same.

Further, as we go forward, the IPR process will become increasingly important, and so we need to ensure that it's a robust, transparent process and the information that is shared with customers is sufficient to allow an informed discussion. And in particular, one item that we've mentioned and commented upon this in the IPR process, and I recognize that this isn't the direct place to address the IPR, but we've noted the direct link between the IPR and the strategic plan, and in my view, if Bonneville is going to continue to keep its program levels in the IPR rather in a rate case, then we need to make sure the IPR is sufficiently robust to allow a good examination of those rates -- of those program levels. And again, more detail on that is in our IPR comments.

The last issue on my agenda is the issue of step rates. Snohomish takes the contrary view as Cowlitz. Several parties, including Cowlitz, argued in favor of step rates. We don't believe that step rates are necessary right now given the rate increase that we understand is coming down the pike. You know, if we were talking double-digits increases, 15 percent rate increases, we might have a different story, but our understanding right now is we're in mid single digits and we believe that step rates bring with it complications that are not worth the small benefit that stepping the rates would provide.

Our experience has shown us that it's really the frequency of small rate increases that cause problems for us in our rate setting, not the magnitude. Again, keeping in mind the realm that we're talking about right now. So I kind of wanted to make it clear, we did not address this in the brief, I wanted to make it clear that it is Snohomish's position that we are not in favor of step rates right now.

And then finally you asked a few questions, a couple on the wind balancing rate. This is not my expertise, but I'll let the panel know that we do agree with PPC and PPC's going to be addressing those issues, I guess, next so I'll defer to Mark on this. One wind-related question I was asked that I would like to address is whether Bonneville should -- whether small wind generators should be exempt from the wind integration rate. We do not believe that they should. We're not in favor of adding a subsidy into Bonneville's rates. It fits with our general belief that if an entity imposes a cost, then they should pay the cost.

Then finally the question -- you asked a question about DSI service and if we proposed a downward CRAC, an up-and-down CRAC or no CRAC at all. Our first reaction was that we don't like the CRAC -- or the ICAC -- excuse me. We oppose the ICAC, but beyond that, I'm not really sure how to answer.

None of the options seem appealing and one concern that I have is that Bonneville has not demonstrated that they've met the Congressional and 9th Circuit direction as far as applying business judgment over its decision -- decisions related to DSIs, and I think the 9th Circuit, the most recent 9th Circuit decision, PNGC case, trusts Bonneville's business judgment to the center of the Agency's decision-making process. So I think right now the Agency's focus should be on providing that business judgment justification. And the evidence that I've seen in the current rate case doesn't seem to meet that standard.

So with that I open up to questions.

MR. NORMAN: I'm sorry. I was late for yours, but I had a question in your brief, the customer-specific charge and whether -- there's been concern over the years about kind of splits within public power Slice, non-Slice, et cetera.

Does Snohomish have any concern that Bonneville's institution of that kind of charge would tend to create a split between small and large utilities who would be affected differentially by a basic charge?

MR. KALLSTROM: I haven't talk with our policymakers about that direct question, but my personal feeling is that if there is a split, then that seems to indicate that there's a subsidy going, and some people don't want to give up the subsidy and that sort of thing. And I think that question's going to be informed as far as the size, and that's definitely one of the factors that needs to be considered when this issue is looked at.

Unfortunately, Snohomish doesn't have the information to make that evaluation. I do think it's a relevant consideration. I just don't know if it's enough to stop the whole thing. I don't think it's enough to stop the investigation or the -- kind of the look into it.

MR. NORMAN: Thanks.

MR. KALLSTROM: Thank you for your time.

MR. WRIGHT: Hang on. I've got a couple more for you.

So the PPC had comments on the rate case process. They're a little vague, so I'll be asking about them, but were you endorsing the PPC comments on modification to the rate case process?

MR. KALLSTROM: I believe so, yes. I did not read them as inconsistent with our --

MR. WRIGHT: So when you said that there our improvements and the work on RAM is good, is that it or is there something else that you're looking for? Because I'm unclear on where you're going with this, what you're looking for.

MR. KALLSTROM: One of the problems is our testimony had a big chunk stricken where we had a lot of recommendations and ideas that we had about the rate case.

MR. WRIGHT: I see.

MR. KALLSTROM: Where this discussion really stemmed from is when we got into clarification, so we worked down the road a little bit into the rate case.

We had a lot of questions about the initial proposal and we tried to pursue those as best we could through clarification, through data requests, but, you know, there are lingering questions.

Bonneville ratemaking process is admittedly very complicated, particularly to someone who's kind of coming in from the outside. So a lot of the suggestions we had were stemmed towards, A, additional time; but B, means of gaining that additional clarification outside of the formal clarification process.

And I can provide you -- unfortunately, off the top of my head, I can only recall one of the specific recommendations, which was this ombudsman role or this individual who would be available to kind of bounce questions off of, and we have to figure out how to answer ex parte issues, but it was really someone we could quiz to gain a better understanding of Bonneville's proposal. But it's those kinds of things we're mostly concerned about.

MR. WRIGHT: This is more of a comment to take back to your clients than anything else. I am frequently but particularly recently increasingly struck by the dichotomy between folks in public power asking us to do more work and then asking us to cut administrative costs, which I just saw happen again here. And, you know, we have tried to resolve a number of issues within public power and which we've said, look, basically as long as we achieve cost recovery, if you guys can work it out amongst yourselves and it's not a violation of the law, we try to find a way to make it work.

But when we do that, we frequently end up with processes that add costs, and then we get to that point when we're doing rates and we get no recognition of that, candidly.

So I will just ask that you take that comment back to your clients, that that dichotomy is becoming just increasingly obvious to me. Struck me with respect to your comments today.

MR. KALLSTROM: I will definitely do that.

MR. WRIGHT: On the DSI issue, so what I was trying to do with the question was push public power outside of its comfort zone. I understand your position. I understand it immensely clearly, let me assure you, that you don't think that anything should happen for the DSIs, sound business principle and the Court decision. I got it.

I'm just saying so if you assume there is a -- from a rate-setting standpoint, if you assume there is a non-zero probability that we might do something for the DSIs and the fundamental promise of setting rates is that we set rates high enough to ensure that we have cost recovery, then we need to do something, and we're trying to create three alternatives.

So if you choose not to answer, basically what happens is you forfeit your right to have input into that decision should we go down that path. And what I heard was we're not going to give you an answer to those on the choice between those three.

So is that the right conclusion to draw?

MR. KALLSTROM: The way -- the initial or the way I led into that response was that we don't like the ICAC, so I think however Bonneville decides to deal with it, it should not involve the ICAC. So of these three choices, it is the third choice.

But there are pieces of the third choice we don't like, for example, moderately higher rate than expected. But the general gist of what I would like to take away from that is we don't like the ICAC.

MR. WRIGHT: Got it. Okay. That helps a lot.

I missed it the first time. Good. Thank you.

MR. KALLSTROM: Anything else?

HEARING OFFICER PETRILLO: Thank you, Mr. Kallstrom.

PPC.

MR. THOMPSON: Thank you, good afternoon. Mark Thompson with the Public Power Council. And I will like to claim my bonus points for wearing my name tag. I can use those probably.

You know, just by way of introduction, I wonder if you made the same mistake as me. It seems like a lot of us entered this rate case thinking, oh, good. The last chance to have sort of a status quo rate case before we get to tiered rate methodology and, thank goodness, the WP-07 supplemental rate case was behind us. It just seems like we got into this process and very quickly it became apparent, now, this is also a very important rate case and it's going to take a lot of time and effort.

And I think a lot of that was due obviously to just that, the timing, you know. The rate case is coming at a time when the region is facing severe economic problems, and I think we submitted this in the IPR process, but I just wanted to reference again the Public Power Council did a survey of our membership to see what they were doing to cut cost and really what was happening at the utility level.

And it was pretty clear from that, you know, that people are hurting, that they feel a real need to cut their costs and keep the rates as low as possible during these times. Seemed like all of the utilities have a goal to cut costs pretty significantly.

Examples of people deferring significant capital expenses, cutting back travel and training for their employees, freezing salaries, freezing hiring and in some cases reopening and renegotiating salaries with their unions. And the range of cuts that people are seeking are also pretty wide but pretty substantial, and I think there were some that were close to the 10 percent range and some were seeking 20 percent reductions of certain portions of their budget.

I know you understand that and Bonneville's been engaged in a process to do a similar thing, but just wanted to emphasize the point, again, that it's real pressure that all the utilities are facing, and to the extent we have an increase here, they feel compelled to find a way to offset that at the local utility level. So it's a harmful prospect to have a rate increase right now.

That said, I think you probably have not been thanked enough by anybody for the efforts of staff and yourself, everyone here today to try to reach, you know, new arrangements that would really help the rates, and we did that and did you that in the rate case.

The great example is the agreement with treasury to increase your liquidity. That's a huge impact on the rates, so thank you very much for those efforts. And we hope that that's an impact -- we hope we realize that when the final studies come out that, yea, we didn't. We weren't in a situation where we were looking at double-digit rate increases, but the final studies have yet to be updated so we want to continue to push for the lowest rate possible.

Today I won't go through everything that we covered in our brief, but I did want to hit a little bit about DSIs, a little bit about the residential exchange and then a few points on wind integration and the wind integration rate.

So like you just said, you're very clear on Public Power's position on DSI service. We are against it. We think it's a bad policy decision to continue to serve the DSIs under current circumstances. But I realize that's an issue that really wasn't debated in the rate case and it's for a different forum, but the issue that is in the rate case is the variable rate.

Should Bonneville adopt a variable rate proposal, either the one that Alcoa proposed or the one that staff has proposed? And even that debate I think has grown a little bit tiresome.

You probably know our position and we know your position, so rather than just say -- repeat that again, I'm trying to think of something new to talk about on this topic, so this is my attempt.

I want to make a proposal, and I hope you'll receive it in the context that I intend to offer it. It's not a real proposal, but I think it helps the discussion a little bit more.

So as I said, the publics are hurting financially. I think there's real pressure to keep rates as low as possible for their end-use consumers. At the same time, the Public Power has been a long-time customer of Bonneville. We paid for the costs of the system. And, in fact, Public Power is one of Bonneville's preference customers.

So among the proposals I would like to make -- I would like you to consider how you would respond to a proposal to have Alcoa and CFAC pay a little bit above the IP rate in order to help out Public Power at this time, due to the economic trials that we're having?

Again, it's not a real proposal, but I hope you consider how you would respond to that proposal if I said you ought to make the DSIs pay more so that Public Power would benefit.

If I had to guess, I think you would say it's inappropriate to require the DSIs to act as a bank for Public Power, giving you loans in the hard times. You would probably say there's a risk of driving the DSIs out of business if we were to do that because they can't afford the costs.

You might also say, you know, just represents basically an unfair cost shift from the DSIs to the preference customers. You might say this is really a particularly bad time to propose something like that given the economic downturn and the challenges that the companies are facing.

So it's probably painfully clear where I'm trying to go with that. I think that all those reasons apply here from the public's perspective. The publics don't want to act as a bank for Alcoa, and they don't think it's appropriate for Alcoa and CFAC. The publics are very concerned that some of their end-use customers will be going out of business due to power rate increase, and adding to that risk really does mean that there's a risk that some of the customers could be going out of business because imposing something like a variable rate. And just fundamentally, we think it bad timing and it's an improper cost shift.

So what I would urge the Agency to do is, you know, we are against service to the DSIs. If you're going to serve the DSIs, do it at the IP rate. It's not a good time. It doesn't further a good policy to implement a variable rate at this time. So from sort of a policy perspective, that's our position on the variable rate.

I would reiterate a few of the points that Jeff Kallstrom just made. We also think from a legal point of view, it's not a good proposition and the Agency's likely to find it's running afoul of the law.

We have a healthy debate going on right now about what the PNGC opinion means, but even if we were to adopt Bonneville's interpretation that the Court said, the past DSI deal was illegal because it was below both the IP rate and the market rate. I would submit that you'd be violating even that interpretation here. You'd be offering the DSIs a rate below the IP rate and below the market rate, and that same Court said that they're not open to Bonneville using creative nomenclature to get around the law.

So I think that would be very applicable if we're in a situation where the Agency is saying, well, trust us. It's the IP rate. It's just a variable IP rate that happens to be lower than what you were picturing when you said the IP rate. I'm not sure that they're going to be very convinced about that.

The Golden Northwest case, as you know, a public power did not completely prevail in that case, and the Court said, well, you know, assuming that there's a valid contract with the DSIs and the preference customers might have to pick up those costs, but they also said you do have some benefit under the statute because at least the DSIs will always be paying a rate that's higher than the preference rate. In this case, you have evidence showing that the Bonneville proposal could very well lead to the DSIs paying an IP rate that's below the PF rate.

Finally there's the Portland General case, not the recent one but the older one, where the Court did review a below IP sale of power to the DSIs. I think they were called fire sales at the time. And the Court did uphold Bonneville and it said specifically: The reason we are going to uphold you is heavily influenced by a few facts. One is the Agency was facing extraordinary circumstances where it was likely facing revenue shortfall. Two, everybody benefitted from this proposal and none were harmed. Those were their specific words. Three, you know, Bonneville was trying to mitigate a financial disaster and actually took actions that increased its revenues.

None of those reasons would apply in this case. Bonneville is not going to increase its revenues from this proposed FY 2010 and 2011 variable rate, and we're not trying to avert a financial disaster to the Agency, and it's not true that everybody's benefitted and nobody's harmed. I think it's very clear Public Power would be harmed, and Alcoa and CFAC would be benefitted.

So without belaboring those points any more, for those same reasons, we would encourage the Agency not to start a new process to look at a long-term variable rate. I think you know you said that the positions don't change very much and we know each other's positions. Those are ours relating to the interim variable rate, and those would be our positions in the long-term variable rate proposal, and I think there are good reasons for abandoning the variable rate proposal.

I'd like to talk a little bit about the residential exchange. First of all, thanks again for allowing your staff to enter into a standstill agreement with the parties. I think that was a good example of everybody, you know, coming together and trying to find a better way to do things so that we're not having to reiterate all of our positions on the residential exchange. We just agreed to carry those forward, so I'm not going to belabor any of our points that we've made before.

However, there's a couple new points that I just wanted to touch on, and they're in our brief, but I think, again, the Agency's going to likely be in trouble in any future litigation to the extent a Court can say, look, Bonneville, you've basically implemented the statute in a way that is not based on an objective reading of the statute, but you've reserved for yourself the right to make the call about what the right result is. And to the extent the Court can do that, it's going to be problematic.

The examples that we point to in our brief and the specific example that I'm referring to are -- there's various -- so assuming Bonneville's right in its interpretation about how conservation should be treated under the rate test, the question arises how do you determine the costs of those conservation resources for purposes of the 7(b)(2) rate test?

And PPC argued since those are resources and resources of significant size, you ought to assume that the cost of those resources are basically capitalized and amortized over 15 years or the useful life of the resource.

Bonneville disagrees with that position and says, well, we'll apply various criteria to determine how much of the costs are expensed and how much is capitalized.

So one of those criteria, Criteria No. 3, it's called the cost recovery criteria, and basically Bonneville staff proposes, well, we'll look. We'll make an allocation between expenses and capitalization and then we'll ask ourselves how much of that -- the cost of that resource is then recovered during the rate test period?

So we argued, you know -- say it again here, that that's not an appropriate inquiry to say, okay, now we've decided what the costs of the resources are, but let's double-check and see if we're getting the right result, if we're getting enough costs in the rate test period such that they come out with the outcome we envision from the rate test.

Another example --

MR. ROACH: Mark, stop right there. I thought the rate test requires a comparison of the program, the 7(b)(2) case for the five years. So how do you not look at what the costs are for those five years? I hear you saying that it's inappropriate to do that.

MR. THOMPSON: You're right. It requires that comparison.

So what I'm saying is the fact that you're doing a comparison should not be a factor in determining how much of the cost should be put into that five-year period. Does that make sense?

MR. ROACH: No. I'm still lost, because in order to do the comparison, you have to know what's in the five-year period. So what is it you're saying that Bonneville is doing differently?

MR. THOMPSON: What we're advocating you should do is you should say, okay, assuming that conservation is a resource that can be applied to load in the 7(b)(2) case, and then what's the cost of that conservation, and then you say, well, it's a resource and it's a big one, and so costs of a resource like that would probably be capitalized and amortized over the useful life of the resource. But that's not Bonneville does.

Then what you would do is say, okay, we've made that assumption for costs. How many of those costs fall within this five-year period, and then you'd have your answer.

But what Bonneville's proposing to do is say, okay, well, we're not going to capitalize over the 15 years. We're going to come up with some other approach, and that approach is going to be informed by how many -- how much of those costs we can put into that five-year period.

So I think it's a -- can easily be painted as an attempt to reserve discretion for the Agency to say, look, we have the discretion to put all these things in the five-year period and get one result or take them all out and get another result. And that in itself is going to be a factor that we're going to take into account.

So I think the point is also applicable to Cost Criteria No. 4, comparability of costs where the Agency says we can look at the difference in revenue requirements between the program case and the 7(b)(2) case, and if they get to be too much of a difference or something that appears to be off to us, then we'll modify our conservation financing in substance and come up with a better, more appropriate result.

Again, I think it's pretty easy to point to that and say the Agency is reserving major criteria so it can have discretion in what the result of the rate test is.

On to wind integration. Just a few points. It's been kind of funny. Some of the PPC staff has been around for a long time and this -- that sounded bad. We have a few people -- we have some older people that have been around the block a few times. And this rate case has sort of brought back this nostalgia of the olden days.

I remember when we used to really argue about technical issues in the Bonneville rate cases, and there was lots of cross-examination, lots of calculations, lots of need for expert testimony, and wind integration was definitely an issue that kind of brought that about again. So my point was it's been interesting to see kind of that nostalgia come back.

So these are very difficult issues regarding wind integration, and I'll just state that PPC's generally been supportive of Bonneville's efforts to quantify the costs to figure out how many reserves you really have to hold out and to make forecasts. And then issues are new and they're tricky and they're technical.

PPC's position is that wind power is obviously a very important source of energy, and it's important for our members and allows them to set their renewable portfolio standards, and it's probably going to be around for a long time, so we need to do this right and we need to allow wind to be integrated into the system.

But at the same time, it's very clear that it is a resource that tends to strain the system a lot, and for that reason, we think it's important to stick to cost causation principles and find out what those costs actually are and then assign them to the correct entities, in this case, the wind generators, so that those who are not purchasing wind aren't picking up the cost of wind power in their rates. And also for the reason that, it doesn't improperly push down on the scales of other renewable resources that might be competing to meet load in the region.

On the question of what persistence -- scheduling persistence you should use, PPC's original position was you ought to stick with two hours. That was the Agency's position.

The Agency then said, well, we've got some new analysis that shows we can go down to -- assuming a 60-minute persistence for scheduling, and PPC is agreeable to that.

We think that there's enough evidence to show that you can make that assumption. But we're not supportive of going below 60 minutes at this time because the evidence showing that generators are, in fact, doing that is based the on very small data sets, and we're just not confident that we can actually rely on that.

So we're not comfortable with an assumption below 60 minutes, except I want to emphasize that JP-6 parties made an alternative rate design proposal in their initial case, and I'd like to reiterate that we would be open to a rate design like that, modified so that the backstop rate is not based on two-hour persistence but instead based on 60-minute persistence.

So in other words, if the generator says, look, I'm a lot better at scheduling than average. I can meet 45-minute persistence. Maybe we should allow them to do that and pay the 45 minute rate. Except if it turns out that they were wrong, they can't meet it, then they need to be put back into a rate where they're paying charges based on 60-minute persistence.

MR. ROACH: Mark, so it's asked several different ways, but are Public Power and the wind community so far apart that there's no reasonable prospect of settlement? Or is there a reasonable prospect?

Ann Fisher was up here saying we ought to explore settlement. So what's response to that?

MR. THOMPSON: What I know is there was a lot of effort put into that, so I would probably be inaccurate or wrong for me to say, yeah, I think there's a good chance to settle this case and be on with it because I think there was a lot of efforts to try to do that, and we weren't able to get there. And I don't think I can comment on all the reasons that people would give for that.

But that said, maybe we're not so far apart. We're talking about similar things here. It's in PPC's interest that the reserves Bonneville holds out to integrate wind are as small as possible. We think we're both aligned on that. And that's why we're saying we ought to give people the chance to be rewarded for being good schedulers.

Another place where I think we're aligned is that we want to encourage and enable self-supply. We don't see any reason to try to keep people on the Bonneville system if they find they can do it cheaper on their own. That's great. Allow them to do that and make a way for them to do that.

So the other thing I wanted to say is PPC would be supportive of allowing people to self-supply. How you do that is kind of tricky. We don't think that the Agency's in a place where you can now say, okay, let's rerun a bunch of studies and break apart the components of the rate and then come up with a final ROD that will specify exactly how crediting will be done and how the rate will change based on self-supply. Unfortunately, we're just not there.

So what our proposal is is that if during the rate period, Bonneville says, look, we've got significant commitments to self-supply, so many, in fact, that we think we can materially lower the rate, then Bonneville would institute a supplemental case, a very limited supplemental case and would reset the rates so that they could be affected at the beginning of 2011.

MR. SILVERSTEIN: Haven't we already identified the relative value of the components and evidence that's already been introduced on the rate case?

MR. THOMPSON: My understanding is we don't think that's sufficient. I mean, I think that there could be --

MR. SILVERSTEIN: So you had said that we hadn't done it. Now you're saying the analysis wasn't sufficient.

MR. THOMPSON: What I can say is PPC's position that is you're not yet to a point where we can just wrap up this rate case with enough information and studies that would allow you to just implement changes to the rate based on self-supply without going through another rate case.

My understanding is that there's a lot of new studies that need to be run, probably in addition to the ones that you've already run. So I think it's more than just what you've done. You did all the right things, but it's just insufficient. I think there's more to be done.

We have a couple of concerns, as well, we think would have to be addressed in that supplemental case that I don't think have had a chance to be fully discussed. One is we have a concern that even if people decide to self-supply and they commit to you that they're going to do that, what happens if they aren't able to do that? What happens if they don't meet that obligation? Can they just come back to Bonneville's system and say, sorry, I guess we're not self-supplying after all, basically lean on Bonneville to sort of be the backstop. I don't think we've developed an appropriate rate to charge to them in that circumstance.

Also even if wind generators form their own balancing authority area, it's nested within the Bonneville control area, does that really let Bonneville off the hook from holding out reserve sufficient to back them up in the case that they do have to lean on the system, in case they aren't able to supply their own reserves?

So what we want to avoid is a situation where Bonneville would be resetting the rates and lowering the rate for the wind generators while not truly reducing the amount of reserves that the Agency has to hold back. And I think that that's something that would need to be worked through in a supplemental rate case to make sure we've gotten to a good position on that.

You asked -- the Administrator asked a question about reliance on the DSO. I'll just point out, we do see a couple of problems relying too heavily on the DSO.

First of all, it's possible that some of the wind generators will challenge its implementation, and if that happens and if they prevail, then Bonneville can't use that. And so we'd be stuck where we have a rate based on the assumption that you could use it, and if you end up not being able to use it, we would have a problem.

The other problem is PPC does fear that even if you are able to enforce it and you continue to do that and it becomes used fairly often, that that's going to present a practical/political problem for the Agency to continue to curtail wind and cut off generation and prevent generators from generating, which prevents them or their investors from realizing some of the benefits from incentives for wind.

So something to consider I think is if we do have a supplemental case because we think we need to change the rates during the rate period, we might at that time have a lot clearer picture of what the DSO looks like. We might actually have some language, and the wind generators and other parties might be able to commit, yeah, this looks good to us. We will not challenge this. And it might make it a little bit easier for the Agency to rely on the DSO in setting up a rate, but that will probably, again, have to wait until the supplemental question.

Another question just briefly you asked should small generators be exempt from the wind integration rate? I got to admit I think that kind of feels like it came out of the blue, so let me know if that was one of our members that proposed that. I think our position --

MR. WRIGHT: Might have been.

MR. THOMPSON: We discussed this. We don't see a reason to exempt small generators.

You know the variability of wind is what causes most of these costs to be incurred, and small generators also add a lot of variability to the system.

Additionally, the rate designed right now is set up so that small generators will, in fact, pay much less than large generators because it's based on installed capacity. So if you're a small generator, you don't have to pay as much as you do if you have a large capacity.

Also we had a concern, you know, if we do exempt small generators. What's to prevent large generators from breaking up their project into smaller components so that they can make each part of the project exempt? Those are some of the concerns we have about exempt wind generators.

With that, I think I'm done with my presentation. I'd be happy to answer any questions.

MR. WRIGHT: So you do have the testimony on the rate case process. Can you just elaborate on what you're thinking about in terms of --

MR. THOMPSON: You commented that it was vague, and I will agree with you, it was pretty vague. And I think also we expressed within that same portion of our brief that we had no complaints about the level of cooperation we got from Bonneville staff. So it's not meant to be a complaint, you know, staff did something wrong here, but it's just to explain sort of a sentiment that we are hearing within our membership which is, look, how come we're having this whole rate case when we have no idea what the rate is? And so we're not really arguing very much about numbers. We're arguing about constructs, and it just feels like we're departing a little bit from the purpose of a rate case.

I don't have great concrete examples how to fix it, but something that comes to mind is we spend a lot of time, we do and so does your staff, complying with kind of formalities in the rate case. Like, for example, it probably took me about 45 minutes to compile my post-hearing exhibit list on the end of my brief, and I think it can probably be recycled.

So we tend to spend a lot of time doing things other than actually discussing the rates and what forecasts look like and what would be a good natural gas price, for example.

The hope is we could come up with a process that would allow us to engage better with each other so we have a better idea what's actually on the table as far as a rate proposal goes.

MR. WRIGHT: Okay. The reason for the exemptions for small wind is a comment that came in in the participant comments which is unusual, so we're dealing with those, and you may want to check those in terms of understanding where that came from.

So the wind folks this morning responded to questions and said as long as the DSO 216 stays where it is, and given where they think the rate is going, and on the basis that we would operate the system in terms of holding reserves consistent with the decision we make in the rate case today, we would still prefer 30-minute persistence, which seems to address some of the concerns that you and your members raised.

Does that mitigate some of your concerns?

MR. THOMPSON: I think it mitigates it.

I think we expressed two reasons why we're nervous to rely too much on the DSO. One is, well, they can challenge it, and if that prevents from you implementing it, then we shouldn't have set a rate based on the assumption we could implement it. And the other reason is we just think it presents a problem to continually apply that.

You know, I heard them say, well, I don't think we'll be complaining if that happens, and that would be great if that were the case, but we're just unsure. And it feels like it could definitely easily be painted as Bonneville's not doing enough for wind generators. Look, they cut off our generation X hours last month and they did it the month before, and we're losing out on production tax credits. And it's easy to turn it into a story that the Agency is doing something wrong, so that's our concern.

MR. WRIGHT: One other question.

MR. ROACH: Steve, if I can just interject. Sometimes phraseology is important and people can come back and use your words against you. I think it would be more fair, I want to test your hearing as well, I don't think that the wind community said DSO 216 where it is, but rather where Bonneville in its testimony has outlined where it's going.

MR. WRIGHT: Oh, okay. Thank you. That's what I meant.

So I want to make sure I understand. You said that PPC proposed an alternative rate design, but then I think you modified it at the podium here. So when you go back to look at that again, let's be clear, what's the modification?

MR. THOMPSON: I seem to have lost power somehow, but the modification is if you go back to the JP-6 -- if you go back to the JP-6 direct case and take the rate proposal there and substitute two hours with 60 minutes, I think that's basically what we're proposing.

MR. WRIGHT: Okay. That was it.

MR. THOMPSON: Thank you.

HEARING OFFICER PETRILLO: Thank you, Mr. Thompson.

Avista.

MR. ANDREA: Good afternoon. Mike Andrea on behalf of Avista Corporation.

At the outset, I'd like to thank the Administrator and the panel for your time today, this opportunity to address this panel. I'd also like to thank your staff for all the hard work they've done in this process.

Just to kind of set out a road map, today I will be addressing only two discrete issues and the other members of the Pacific Northwest investor-owned utilities who joined in our brief will be addressing some other issues, and I'll set out just kind of a quick road map of what those issues will be so you know where we're going and who'll be talking about what. It's not meant to be an exclusive list and they may have other issues that don't make the list.

The two discrete issues that I'll be addressing are whether the output from PRC's 10 percent share of Boardman coal plant should be included in the section 7(b)(2) resource stack. That will be the first one.

The only other issue that I'll address is the shares the savings approach to allocating benefits from the DSI reserves that the Pacific Northwest investor-owned utilities advocated in their brief.

Ryan Flynn for PacifiCorp will be following me, and he will address the 50 percent rule that BPA has said it will apply when collecting assorted look-back amounts.

David White, attorney for Portland General

Electric Company, will address the treatment of the 7(b)(2) case of conservation costs that are expensed in the program case.

Mr. Strong, attorney for Idaho Power Company, will address some Idaho Power specific issues, and I'll let him go ahead and talk about what those are.

Don Kari for Puget Sound Energy will address the treatment of conservation in the 7(b)(2) case, allocation of a share of the 7(b)(2) industrial adjustment, 7(c)(2) delta surplus sales and adjustment of the CRAC allocation to reflect the recovery of the portion of the costs causing CRAC from Slice customers.

So those are generally the major issues that we'll be addressing. Obviously, we welcome any questions that you may have, whether they're on that list or not. If I can't answer them, I'll hopefully point you to the attorney who'll follow who will be able to answer those questions.

So starting with whether PRC's interest in Boardman should be in the 7(b)(2) resource stack, it's our position that it should not. According to BPA's testimony and as we've seen, BPA is treating this resource as a Type 1 resource, which is a resource that's owned or purchased by a public utility or cooperative. Even though there's no dispute that that resource has been sold out of the region to Turlock Irrigation District under what we understand to be a long-term contract, given that the resource is clearly not owned or purchased by a public utility or cooperative and, therefore, it does not satisfy the threshold requirement for inclusion in the 7(b)(2) resource stack.

What we gather from Bonneville's materials is they're relying on reasoning from WP-07 supplemental rate case to justify its decision to include the resource in the Section 7(b)(2) resource stack. And that reasoning, as I understand it, is that if the resource was owned by a public utility or cooperative, the resource continues to be owned or purchased by the public utility or cooperative even after the public utility or cooperative sells that resource to another entity that is not a public utility or cooperative, or for that matter, is a public utility or cooperative or a regional IOU that commits to resource load.

BPA stated in the WP-07 supplemental ROD that this must be true because the resources included in the Section 7(b)(2) resource stack if it's purchased from the preference customer by the Administrator. In BPA's view, that appears to prove that the owned or purchased means owned or purchased prior to the sale. We respectfully think that that is not correct.

Section 7(b)(2), little i, expressly states that resources purchased from preference customers by the Administrator are included in the Section 7(b)(2) resource stack. There is no similar provision that allows resources purchased by entities such as Turlock to be included in the Section 7(b)(2) resource stack.

The reason for this I think is clear. Resources sold by preference customers to entities such as Turlock, for that matter other preference agencies that commit the resource to load, are simply not available to the Administrator to be used to meet the preference customers' general requirements. They're just simply not available.

The intent of Section 7(b)(2) is clear in this regard. Only resources that are available to the Administrator, either because of the Administrator's already purchased such resources from preference customers or because the Administrator can purchase such resources from preference customers, may be included in the 7(b)(2) resource stack.

As I said, PRC's interest in the output from the Boardman coal plant has been sold to Turlock. Accordingly, that resource has not been and cannot be purchased by the Administrator from preference customer to meet preference customers' loads or meet preference customers' general requirements. Again, it simply is not available as contemplated by Section 7(b)(2). It necessarily follows that such resource is not a Type 1 resource and cannot be included in a Section 7(b)(2) resource stack.

On the issue of --

MR. ROACH: Let me ask, so it's your position that at the time Bonneville does the test, it has to be available?

MR. ANDREA: Right. I don't think there's any basis for assuming that a resource that's been sold, especially out of the region to an entity like Turlock, can be available during the rate period to meet the general requirements of preference customers.

MR. ROACH: Extrapolating from that, it's your position that Bonneville can't take a sort of with and without act approach, look to see what in the 7(b)(2) world, what resources Bonneville could have acquired from preference customers that were owned or operated by them?

MR. ANDREA: I'm not sure I fully understand what you mean, with or the without portion.

MR. ROACH: If I recall, the Boardman sale was after the Northwest Power Act had passed, and so in a world where the Northwest Power Act hadn't passed, I'm not saying this as a matter of evidence but perhaps argument, that it may well be possible that Bonneville might have acquired that resource. Although, I think that's a stretch given the resource acquisition authority of Bonneville -- afforded Bonneville under the Northwest Power Act.

I think I hear you saying that the ownership is a strict test that applies only during the period that Bonneville does the test.

MR. ANDREA: I think that's correct. I think you have to look at -- I'm sorry -- at what resources are available to the Administrator to meet those general requirements, and, you know, it seems -- I really haven't thought your question through entirely, but it just strikes me as sort of arbitrary to try and determine kind of given the realities that maybe you would have purchased those in some different world.

MR. ROACH: Okay.

MR. ANDREA: With regard to share the savings issue, we briefed this issue, but we just wanted to hit on it kind of for emphasis.

DSI service benefits are required to provide a portion of BPA's reserves for firm power loads within the region. That's clear from Section (5)(d) of the

Northwest Power Act. The value of such reserves should be shared among Bonneville's customers.

It's our position that BPA should adopt the share the savings approach advocated by Pacific Northwest investor-owned utilities when crediting the DSIs with the value of reserves. Under this approach, basically BPA would credit the DSIs for half the value of the reserves provided.

BPA has previously used this approach, it's not novel, and it was affirmed by the 9th Circuit in the Central Lincoln case, so it's clearly within the Administrator's discretion to apply such approach.

We do recognize that BPA did not use the share the savings approach in the '96 rate case and instead credited the DSIs with all the savings. The conditions that existed that may have justified that at the time don't exist. As we understand it, Bonneville took that approach in '96 because it was concerned that varying the credit the DSIs for all of the projected value reserves would establish an IP rate that exceeded market rate and BPA could lose DSI load. Again, that environment does not exist today. The IP rate is not near above market prices.

BPA acknowledged in its rebuttal testimony that the competitive forces that existed in '96 are not present today and there is less reason for losing DSI load to competitors.

Also adoption of a share the savings approach is consistent with Section (7)(g) of the Northwest Power Act which requires the equitable allocation of all costs and benefits not otherwise allocated. Accordingly, the BPA should adopt the share the savings approach to the DSI reserves as advocated by Pacific Northwest investor-owned utilities.

DSI reserves must provide benefits to the region. Crediting 100 percent of the reserves to the DSIs means only the DSIs and not the region receive benefits from the reserves.

Finally, if BPA is concerned that share the savings approach would result in an IP rate that may prevent the DSIs from operating, that concern is misplaced.

As we demonstrated in our initial brief, Bonneville should project significantly larger reserve benefits than BPA is currently projecting. Such a larger reserve benefits properly valued should result in lower DSI rate even under a share the savings approach. Moreover, Bonneville is now proposing a variable DSI rate which would enhance the viability of DSIs.

For all of these reasons, we urge the

Administrator to adopt the share the savings approach for DSI reserves. And that was all I had. Those are my points, but I'm happy to take any questions you might have.

MR. WRIGHT: No.

MR. ANDREA: Thank you.

HEARING OFFICER PETRILLO: Thank you, Mr. Andrea.

PacifiCorp.

MR. FLYNN: Thank you, Your Honor. Good afternoon. My name is Ryan Flynn appearing on behalf of PacifiCorp.

Today I'd like to address the provision of REP benefits to each utility of not less than 50 percent. Notwithstanding the fact that we do not think that there should be any look-back in the first place, PacifiCorp supports BPA's position in this proceeding with regard to the 50 percent minimum threshold. We appreciate staff's and the Administrator's efforts to strike a balance in this proceeding in this regard.

PacifiCorp would like to make the following three statements in support of BPA's proposal. First, to the extent that any look-back is undertaken, BPA's proposal is not a departure from the WP-07 ROD. Contrary to suggestions by some parties to this proceeding, BPA has not reversed itself or otherwise changed course from the approach established in the WP-07 S-ROD.

BPA determined in the ROD that it would adopt a goal for repayment of look-back amounts within a seven-year period where possible and provided that the amount of benefits for any IOU would not fall below 50 percent.

In this case, BPA is proposing to adopt the same approach and has determined it is appropriate to continue the 50 percent threshold.

Second, to the extent that any look-back is undertaken, BPA's proposal strikes an appropriate balance. Some parties have suggested that this is the wrong policy choice given the current economic circumstances, and PacifiCorp would note that the same recession -- recession-related economic hardships are also impacting IOUs, small farms and residential customers, particularly if you reside in Oregon, which is experiencing abnormal unemployment rate today. If you look more specifically at PacifiCorp-served counties, it's an even more substantial impact.

Consistent with the WP-07 S-ROD, BPA is attempting to balance the impacts of its decisions on residential and small farm ratepayers under these circumstances, and PacifiCorp supports that approach.

Finally, to the extent that any look-back is undertaken, BPA's proposal is fair and reasonable. In the WP-07 S-ROD, BPA established a number of policy objectives with regard to repayment look-back amounts. In light of those objectives and as applied in this proceeding, BPA has determined it's appropriate to maintain the 50 percent minimum benefit level. PacifiCorp believes that BPA's proposal is fair and reasonable under the circumstances.

So that essentially concludes my remarks here today, and I'm happy to take any questions. Thank you.

HEARING OFFICER PETRILLO: Thank you, Mr. Flynn.

MR. MILLER: Your Honor, I think that there's been some interest in calling back a couple of parties from earlier. I don't know. Steve can correct me if I'm wrong, but my understanding is that one of -- Mr. Hall actually has to leave, and if there was a follow-up question for Mr. Hall and Mrs. -- Ms. Skidmore, it would be an appropriate time maybe if we could squeeze them in.

MR. WRIGHT: If that works. If the other parties are willing. We've got follow-up questions for the wind folk we'd like to get in before they have to

leave.
HEARING OFFICER PETRILLO: That's okay with me.
Mr. Hall.
MR. HALL: It's okay with me. You want both of us to --
MR. WRIGHT: Sure, might as well.
MR. HALL: This is Stephen Hall for the Northwest Wind Group.
MS. SKIDMORE: And Lara Skidmore for Iberdrola.
MR. NORMAN: I had a question just briefly, and I apologize if I'm asking you to kind of over-specify a prior statement, but I'd like to know if you can tell us if hypothetically the delta in the wind integration rate between 30-minute and 45-minute persistence were only a dollar a megawatthour, would that change your point of view about whether you'd prefer 30- or 45-minute persistence?
MS. SKIDMORE: Without having the benefit to talk with my client about this, I mean, I guess I would say you're talking about the delta. I'm not sure that we're as concerned about the delta. We are advocating 30 percent -- I mean, 30-minute scheduling accuracy because we think that's where it should be, and that that's a better projection, a better use of the reserves and something that's achievable.

And so as far as the price goes for us, for our self-supply decision, it depends on the bottom line. So I don't know where that dollar is relative to something. If it's above -- if both 30 and 45 are above our number, I think we're going to do what we're going to do regardless. If it isn't, if something is at or below the number we've given you guys, then we might have a different course. But that probably is dependent on what level of forecast accuracy you're at, depends on what the number is. So I don't know if that answers your question. Steve's answer might be different.

MR. HALL: Maybe I don't completely understand the question that you asked, Paul, but if you're asking that if the rate is going to be a dollar per kilowatt month and --

MR. NORMAN: No. Let me ask my question again.

So you both said on balance, you'd rather take the potentially higher risk of curtailments if the DSO is being implemented on a 30-minute persistence than a 45-minute persistence. You'd rather take that risk than be locked into a higher rate and 45-minute persistence.

MR. SILVERMAN: $3 was used for conversation purposes.

MR. NORMAN: I'm not holding you to it, but $3 a megawatthour was, I think, the figure you mentioned.

I'm not trying to hold to you that.

MS. SKIDMORE: Thank you.

MR. NORMAN: My question was if hypothetically if you knew that the savings in the wind integration rate if you go from 45 minutes to 30 minutes is only $1 per megawatthour, would that change your mind? Would you say, oh, well, if that's all I save, then I'd rather stick with 45-minute persistence?

MR. HALL: That is assuming that you'd also have the WIT protocol of the DSO 216?

MR. NORMAN: No change in DSO, but, of course, with the 30-minute persistence, it's going to trigger more often.

MS. SKIDMORE: Well, again, I think my client feels pretty confident in its schedule at 30 minutes, so we would prefer to see the number as low as possible and we prefer to see 30 minutes.

MR. HALL: And subject to check for the Northwest Wind Group, I believe that they would also prefer the 30-minute persistence in connection with the WIT protocols, the DSO 216.

MR. NORMAN: Sorry to spring that on you, but thank you for your answer.

MR. WRIGHT: That's it.

HEARING OFFICER PETRILLO: Thank you.

PGE.

MR. WHITE: Good afternoon. My name is David White and I'm appearing on behalf of Portland General this afternoon.

On behalf of Portland general, I would like to first thank Bonneville staff for all its hard work leading up to and continuing through this rate case. Since 2007, it's been pretty much a full sprint with no break between the WP-07 supplemental case and this proceeding, and we just really appreciate Bonneville staff working with us and the other customers in a highly professional cooperative spirit throughout these demanding and challenging times.

I'd just like to touch on two topics. The first is one of the wind integration questions that was posed to the parties, and my comments on this are just for Portland General Electric and do not necessarily reflect the views of the other investor-owned utilities.

On the question of should small wind generators be exempt, Portland General's position is that there should be no exemption for small wind generators. As you heard this afternoon, our position is similar to some of the other publics. We believe that Bonneville should follow cost causation principles, so regardless of the size of the project, if a wind project is causing costs for the Bonneville system, that project should be subject to a Bonneville wind integration rate.

And we also believe that setting an exemption level will lead to gamesmanship. As you heard earlier, projects will be divided up and try to fit underneath that exemption, so we would oppose a small wind generator exemption.

The second topic I'd like to address --

MR. WRIGHT: Actually -- I didn't actually read the comments. I heard about them, and if I got it wrong, I apologize. But I think part of the argument is that the PUC has said what it cost for purposes and that's influencing the decisions here.

Do you know whether PGE would choose not to purchase from these small wind generators as a result of integration charges that Bonneville is potentially placing on them as a result of this rate case? Would that actually be the tipping point for PGE purchase of a small wind generator?

MR. WHITE: You know, I don't know the answer to that question. I don't know whether or not any projects are in that position where delta one way or the other in terms of wind integration rate would cause them to make a decision not to acquire from that wind generator.

MR. WRIGHT: Thank you.

MR. WHITE: The second topic I'd like to address is the 7(b)(2) issue and it relates to the initial proposal's treatment of conservation costs that were treated as operating expenses in the program case. And for shorthand, I'll refer to those as expensed conservation.

In the 7(b)(2) case, the initial proposal's position was that it should defer and recover over a five-year period those conservation costs that were expensed in the program case.

It's our position that expensed conservation should be covered in the year in which it is incurred, or at a minimum, in a period less than five years. In this regard, we're asking for nothing novel. It's standard industry practice to recover such expenses in the year the costs are incurred, and prior to WP-07 supplemental case, it was Bonneville's treatment of expense conservation in both the program and the 7(b)(2) case.

We're not asking for anything exceptional here. We're asking for, in fact, symmetrical treatment. Bonneville continues to follow the industry practice of recovering expense conservation in the year it's incurred for the program case, and we're asking that

Bonneville recover these expense conservation costs in the same manner in both the program case and the 7(b)(2) case.

This is an important issue for the investor-owned utilities because it has a substantial impact on conservation costs and the level of residential change benefits we receive. Conservation costs in the 7(b)(2) case with the five-year recovery period for expense conservation are about $19 million lower in the 7(b)(2) case than in the program case.

By contrast, if you recover the expense conservation in the year that it's incurred, which is our proposal, it results in nearly equal conservation costs between the program case and the 7(b)(2) case, so this has on an annual basis about a $19 million impact on our residential exchange benefits. We see no legitimate basis for using a different recovery period for the 7(b)(2) case as compared to the program case.

A change in the recovery period is not one of the five assumptions that must be made in the 7(b)(2) case. In this case, Bonneville's primary reason for the five-year recovery period is the claim that recovering these expense conservation in the year that it was incurred would cause a rate spike in a 7(b)(2) case for the fiscal year 2010, and we find this reason unpersuasive for three reasons.

First, the 7(b)(2) case is applied over a six-year period, so there's no reason to unduly focus on one year over the other over the entire period. The use of the six-year period ensures that the effects of any particular year will be mitigated and avoided.

Second, all of the other criteria that Bonneville staff lists for evaluating the recovery period for expensed conservation, and those are the financing cost impacts, the cost recovery during the period and the comparability of costs, all these factors favor a short recovery period, or a recovery period -- or recovering the costs actually in the year that it was incurred.

The analysis under Bonneville's decision criteria taken as a whole, therefore, favor not deferring the expense conservation but recovering it in the year that it was incurred, or at a minimum, recovering the expensed conservation over a period less than five years.

In this regard we note that Bonneville's testimony concludes that a four-year recovery period would be very similar in terms of achieving its objectives as the proposed five-year period would.

Finally, the rate spike for the fiscal year

2010 at best justifies a delayed recovery for fiscal year 2010. It offers no basis for a five-year recovery period for the years after 2010. So at a minimum, we believe Bonneville should recover expensed conservation for all other years in a six-year rate period, fiscal year 2011 through fiscal year 2015, in the year that the expense conservation is incurred.

That concludes my prepared remarks. We thank you very much for your time this afternoon and for the opportunity to present our arguments. And I'll welcome any questions.

MR. WRIGHT: No.

MR. WHITE: Thank you.

HEARING OFFICER PETRILLO: Thank you, Mr. White.

Let's go ahead and take a ten-minute break for the reporter, but it will only be ten minutes, so have you back here then.

(Recess taken.)

HEARING OFFICER PETRILLO: During the break, we learned that the participant who submitted the comment that was responsible for the Administrator's last question regarding wind generators is present in the hearing room, and I've learned that the panel would like to hear from that participant. And so what we intend to do is to -- is that after we adjourn these proceedings, to reopen to hear that participant's comments.

I'm assume that's an acceptable procedure, Mr. Wright?

MR. WRIGHT: Yes.

HEARING OFFICER PETRILLO: Thank you. So that's what we will do. Right now we'll go to Idaho Power company.

Mr. Strong.

MR. STRONG: Thank you. My name is Blair Strong and I'm appearing for Idaho Power company.

One recollection I have with the historical perspective is many years ago in this hearing room and other places where hearings were conducted, there weren't laptops all over the tables, and the fact that we have laptops and Internet connectivity even during the hearings is a sign of the courtesy and consideration of Bonneville'S staff for the participants in the rate case, and we've always been treated with courtesy and appreciate it during this hearing as well.

I am going to speak only to the look-back and its application to Idaho Power. We have joined in the testimony and the briefs of the other investor-owned companies, and my colleagues, Messrs. Andrea, Flynn, White and Kari are addressing the issues which are contained, discussed in those combined filings.

On behalf of Idaho Power, I need to say, of course, at the outset that we don't agree that there should be any look-back whatsoever, but the decisions that are required to be made in this case respecting the look-back balance are merely an application or an extension of policy determinations that were already made in the WP-07 supplemental case. So we're starting from that step.

We are suggesting in our briefing and otherwise that Bonneville should resist the assertions or temptations of other parties that it should revisit policy from WP-07 as applied to Idaho Power, and that the recovery of look-back amounts should take some form other than reduction of REP benefits as applied to Idaho Power Company.

In this connection, it's important to note that we believe it's incorrect to assume that Idaho Power will not be in a position to receive REP benefits sometime in the future, subsequent to fiscal years 2010, 2011. BPA's own witnesses noted that if Idaho Power adds new resources, that would change the complexion and the relationship between Idaho Power's average system cost and the prior firm exchange rate. And just one illustration of the fact that change, if I can borrow a metaphor from the wind case, change is ablowing, is the fact that Idaho Power has already filed with the Idaho Public Utility Commission an application for certificate of convenience and necessity for the Langley Gulch power plant, and the commitment estimate contained in its filing is about $427 million.

There are other resources that may likely be coming down the line -- may -- we don't know the timing of those. We don't know what the regulatory treatment of those might be. We don't know what Bonneville's future exchange rates would be. All that is somewhat conjectural, but it clearly is an error to assume, based on the record in this case, that Idaho Power would not be in a position to receive REP benefits in the future.

With respect to Idaho Power, therefore, the only determination that BPA really needs to make in this case, in this rate case, for purposes of determining its revenue requirements is whether it is likely that Idaho Power will be or will not be participating in an exchange agreement during the fiscal year 2010-2011, during the rate period. And there again, the record's fairly clear that it's unlikely that within the next few months or within the period of time that you will be designing rates for that rate period that Idaho Power will execute an exchange contract. It's unlikely that disputes of significant concern to Idaho Power that are currently subject to litigation will be resolved, and it's unlikely that Idaho Power would sign a new RPSA in time to effect the revenue requirement for this rate period.

Given the unlikelihood of that event happening, Idaho Power's status with respect to look-back amounts is -- if I can characterize it as such -- is simply neutral and the Commission -- I'm sorry -- the Administrator need not make any determinations one way or the other. It doesn't have to, and that should be maybe a relief. There's so many issues that you have to face. Why take on one which you don't have to face at this time which itself would be subject to a lot of speculation and disagreement?

Even if look-back balances, however it is determined, and if it were determined and it probably won't be in the next couple months, but even if it were determined that look-back balances from Idaho Power were owed and immediately collectable, we believe that it would be reasonable for BPA to continue to follow the general approach similar to your approach in the -- with respect to look-back amounts adopted in the WP-07 supplemental ROD. That is to reduce REP benefits in the future consistent with BPA's goal of amortizing look-back amounts, subject to preventing those benefits under any contract from falling below 50 percent in any year, understanding, of course, that Bonneville reserved the right to revisit the precise threshold, the 50 percent threshold, from year to year.

We believe that's a sound approach. Bonneville has preferred long-term arrangements in implementing regional contracts, including the exchange contract, and with that preference in mind, resolution of the look-back issue itself can be resolved in a long-term setting.

Idaho Power - I guess I can't avoid not talking about the deemer balance just very slightly - Idaho Power does not agree with some testimony in this case respecting the amounts of the deemer balance attributed to Idaho Power. Bonneville recognized in WP-07 supplemental that deemer issues were not ripe for resolution in that case, and for similar reasons, we don't believe they're ripe for resolution in this case, including a resolution of the precise amount.

However, assuming that deemer balances are owed, and that's, again, an arguendo because we don't concede they are, but assuming that they are owed, we believe that the best approach to resolve that balance issue is by settlement and that a settlement should balance a couple of equities. One is the reduction of REP benefits over time to discharge that balance, if it is owed, and the other is a receipt by Idaho Power's residential and small farm customers of a portion of the benefits that they would otherwise be entitled to at the commencement of an exchange contract.

That's all I have to say, unless you have any questions.

MR. WRIGHT: No. Thank you.

HEARING OFFICER PETRILLO: Thank you, Mr. Strong.

Puget Sound, Mr. Kari.

MR. KARI: Good afternoon. I'm Don Kari appearing on behalf of Puget Sound energy, Inc. I appreciate the opportunity to appear before the panel this afternoon and I appreciate the efforts, and equally importantly the tone set by BPA staff in this proceeding, so thank you.

First, I will address conservation in the 7(b)(2) resource stack. Under BPA's general approach to conservation, BPA first removes conservation costs from the 7(b)(2) case and augments the general requirements of BPA preference customers in the 7(b)(2) case for the conservation assumed to be not achieved. Then conservation is included in the 7(b)(2) resource stack and drawn when needed if it is the least cost resource. If this doesn't sound new, it's not surprising. This is the general approach in the 7(b)(2) case BPA has used since 1985.

In this proceeding, BPA proposes to treat BPA-funded conservation in preference customer service territories as a Type 1 resource; i.e., acquired by BPA, but only if the preference customer is a load-following customer.

However, BPA should treat BPA-funded conservation in the service territories of non-load-following preference customers in the same manner.

MR. ROACH: Hey, Don, is that what Bonneville has done since 1985?

MR. KARI: I don't believe so, but I don't know, Randy.

MR. ROACH: Okay.

MR. KARI: The effect of conservation in BPA preference customer service territories is to reduce the preference customer's net requirements, by which I mean the amount of power the preference customer is entitled to purchase under Section 5(b) of the Northwest Power Act. Any conservation in service territories of BPA preference customers that results from BPA expenditures and reduces the BPA preference customers net requirements is and should be treated as Type 1 resources purchased by BPA. Such BPA expenditures reduce the net requirements of the preference customers and thereby benefit BPA. Accordingly, all BPA-funded conservation and preference service customer territories should be treated as Type 1 resources.

Now, BPA in this regard reasons that BPA-funded conservation in non-load-following customer service territories does not affect purchases, purchases as opposed to net requirements, by customers in the short-term and, therefore, should not be treated as conservation in a 7(b)(2) resource stack.

However, this reasoning is flawed for several reasons. First, there is every reason to believe that when the non-load-following customers establish their purchases from BPA, they are aware of and take into account BPA conservation programs. But more fundamentally, even if BPA conservation does not affect non-load-following customer purchases in the short-term, in the program case, BPA cannot ignore such conservation in the 7(b)(2) case.

The Northwest Power Act Section 33 defines conservation as including any reduction in electric power consumption as a result of increases in the efficiency of energy used, production and distribution. The Northwest Power Act does not limit conservation to only consumption reduction that reduces purchases from BPA. Thus, conservation is a resource and must not be disqualified from the 7(b)(2) resource stack based on whether or not that conservation produces a short-term reduction in purchases from BPA.

This is consistent with the Administrator's WP-07 supplemental Record of Decision, WP-07-A-05 at page 456, conformed, which states as follows regarding conservation acquired by BPA. And I quote: Conservation is defined in the Northwest Power Act as a resource. In addition, conservation is acquired by BPA under Section 6. Under the plain language of the Act, conservation resources acquired by BPA are an available resource for the 7(b)(2)(d) resource stack that may be used to serve 7(b)(2) case load to the extent it is needed and it is among the least expensive resources available, end quote. I've omitted the citations to the statute.

So consistent with the Northwest Power Act --

MR. ROACH: So are you arguing for Bonneville to do something different in this case than it did in that case?

MR. KARI: Yes.

MR. ROACH: Notwithstanding the language you just quoted?

MR. KARI: Right. The language in this case indicates that conservation is a resource. It doesn't say conservation is a resource -- excuse me. The language in WP-07 supplemental says that conservation is a resource, which it should, and is correct. It doesn't say conservation is a resource if it reduces the purchases of a preference Agency. It just doesn't have that qualifier on it. The conservation is a resource, therefore, it should be considered as eligible for the 7(b)(2) resource stack if it otherwise qualifies and is the least cost resource then available in the stack and not be disqualified from inclusion in the stack merely because of a conclusion that it does not decrease the short-term purchases by the preference Agency from BPA.

MR. ROACH: What would you do -- say you wouldn't make any adjustment. You started out talking about how Bonneville previously made the adjustment to load and then took the resource and they added it to the resource stack.

I assume in this case there would be no adjustment to load because it's not a load-following customer, but you would still go ahead and use the resource per your logic?

MR. KARI: No. The reason Bonneville puts -- makes -- it's a -- Bonneville's general approach to conservation is a two-piece approach and it's linked. Conservation is removed from the load and the conservation then goes in the resource stack.

When I say conservation is removed from the load, that means the 7(b)(2) case loads are augmented by an amount equal to conservation. And that's exactly what we believe should happen even in the case of a non-load-following customer. Otherwise, you have sort of a phantom load.

Bonneville's out paying for conservation, acquiring it, and you go to a 7(b)(2) case and it's somehow just gone. We think it's entirely consistent in the 7(b)(2) case to increase the load by the amount of the conservation and put that conservation in the resource stack.

Consistent with the Northwest Power Act and the language of the WP-07 supplemental Record of Decision that I just described and was discussing with Randy, BPA under its general approach to conservation must assume the conservation in non-load-following preference customer territories is available for the 7(b)(2) resource stack. And as a necessary logical part of that same necessity of including a resource stack, then the general requirements of the 7(b)(2) case -- general requirements of the preference customers in the 7(b)(2) case, must be increased by that amount of conservation. The linchpin is the requirement of the Northwest Power Act that the conservation be treated as a resource.

Increased load in the 7(b)(2) case from the treatment of conservation as a resource should be treated just the same as increased load in the 7(b)(2) case that results from the within an adjacent DSI load. Both increases in load in the 7(b)(2) case should appropriately be treated as increases in the general requirements in the 7(b)(2) case and be met as necessary with resources from the 7(b)(2) resource stack.

So in short, again under BPA's general approach to conservation which takes this approach to augmenting load in the 7(b)(2) case and putting conservation in the resource stack, BPA-funded conservation savings in service areas of non-load-following BPA preference customers are Type 1 resources; i.e., resources acquired by BPA.

Now, the only basis I believe on which BPA might conclude that conservation savings funded by BPA in the service territories of non-load-following preference customers are not Type 1 resources is that such conservation savings are not acquired by BPA. BPA paid for the conservation, but if it's not a conservation, Type 1 resource, the only thing that's left is somehow a conclusion that the conservation savings are not acquired by BPA.

But there's an interesting consequence of reaching that conclusion. If BPA concludes that BPA-funded conservation savings in the service territories of non-load-following preference customers are not Type 1 resources, then it follows such resource savings cannot be acquired by BPA, and under BPA's interpretation of non-load-following customers, those conservation savings are not committed to load because they don't -- because BPA has concluded that those conservation savings in the service territories of non-load-following customers don't reduce purchases from BPA in the short-term.

Conservation savings by preference customers that are not acquired by BPA under Northwest Power Act Section 6 and they're not committed to load under Northwest Power Act Section 5(b) are Type 2 resources, therefore, all conservation savings of non-load-following BPA preference customers are Type 2 resources if BPA concludes BPA-funded conservation in non-load-following preference customer service territories are not Type 1 resources.

MR. ROACH: If you could remind me the distinction between a Type 1 and a Type 2 resource and the importance of the distinction.

MR. KARI: Yes. Type 1 is conservation that is acquired by BPA, or resources, Type 1 resources, any kind of resource, conservation or otherwise, acquired by BPA.

Type 2 resources are resources of preference agencies that are not acquired by BPA and are not committed to load under Section 5(b) of the Northwest Power Act, and I'm pointing out that the logical consequence of not recognizing that BPA-funded conservation in non-load-following service territories as Type 1 resources means that all conservation in the service territories of those customers must be a Type 2 resource.

We think the appropriate answer is that the BPA-funded conservation in those service territories is Type 1, but if that is not Bonneville's conclusion, then we would submit that Bonneville must conclude that all conservation is Type 2 resource.

And, of course, again Type 2 resources, same treatment. They should, under BPA's general approach to conservation, augment the load in the 7(b)(2) case and be included in the 7(b)(2) resource stack.

MR. ROACH: Don, a couple of times in your remarks it seemed like you were being careful to reference conservation being acquired to meet load in the short-term. What's the significance of that?

MR. KARI: The significance is that Bonneville's rationale for not -- at the present time Bonneville's rationale for not including conservation in the non-load-following service territory of preference agencies as a resource in the 7(b)(2) resource stack and augmenting the load in the 7(b)(2) case is that in the short term, non-load-following customers, the conservation doesn't decrease the purchase from Bonneville by definition. That's what a non-load-following BPA customer is, in the short term they have fixed their purchase from BPA.

MR. ROACH: But the extrapolation of that is that it could reduce load in the long term.

MR. KARI: And that's another reason that resource should, in fact -- that conservation should, in fact, be a Type 1 resource you can get right there. You wouldn't have to pass go. You wouldn't have to pay $200. You can just reach what I submit the correct conclusion --

MR. ROACH: Even if that long term is outside the five-year 7(b)(2) period?

MR. KARI: Even if it's -- well, see, I don't agree that it is. The first proposition --

MR. ROACH: But what if it were?

MR. KARI: You're asking me to assume that non-load-following customers don't take Bonneville conservation programs in account in setting their demand on BPA, and I am sorry. I cannot accept that -- that premise. I'm sure they do. There just can be no doubt about that. So they do take it into account.

Anymore questions?

That one was easy.

MR. ROACH: What would be hard?

MR. KARI: I'm glad you asked me that.

Next I would like to address the allocation of 7(b)(2) industrial adjustment, 7(c)(2) delta to surplus sales. So let me just provide a little context, set the table if you will.

The 7(c)(2) delta is the amount by which the costs allocated to the IP rate exceed the revenues that would be generated by an IP rate equal to the preliminary unbifurcated PF rate, plus the typical industrial margin minus value of reserves credit.

So basically the 7(c)(2) delta is the amount by which the costs allocated to the IP rate exceeds the revenues you generate from an IP rate set using the unbifurcated PF rate. BPA then takes this 7(c)(2) delta, this excess, and allocates that to the preliminary unbifurcated PF rate and the NR rate. This allocation results in an IP rate that's reduced by the 7(c)(2) delta.

Now, as noted in the initial brief of the Pacific Northwest investor-owned utilities, BPA fails to allocate a pro rata share of the 7(c)(2) delta to surplus sales. I just note that. I won't go into that. It's addressed in the brief, if you'd like to see that at page 56.

After the 7(c)(2) adjustment, BPA runs the 7(b)(2) rate test. If the 7(b)(2) rate test triggers, the PF preference rate is lowered by the 7(b)(2) trigger amount which alters the relationship between the IP rate and the PF preference rate.

BPA has concluded that the relationship between these two rates should not be changed in this manner and, therefore, next performs the 7(b)(2) industrial adjustment, pursuant to which BPA recalculates the IP rate using the preference rate as lowered by the trigger amount.

In 7(b)(2) industrial adjustment, 7(c)(2) delta is the reduced revenue from the IP rate caused by using the PF preference rate as lowered by the 7(b)(2) trigger amount to calculate the IP rate. I should note that it's not clear that the 7(b)(2) industrial adjustment step is required by the Northwest Power Act, but I'm not going there today.

BPA proposes to allocate the entire 7(b)(2) industrial adjustment, 7(c)(2) delta to the PF exchange rate and the NR rate and to allocate none of the 7(b)(2) industrial adjustment, 7(c)(2) delta to surplus sales and none to the PF preference rate. Indeed BPA's proposal allocates the entire 7(b)(2) industrial adjustment, 7(c)(2) delta to the PF change rate since there are known projected NR sales.

Thus under BPA's proposal, the PF exchange rate bears not only its full share of the 7(b)(3) trigger amount allocation determined by BPA, but also inappropriately, in my view, bears the entire 7(b)(2) industrial adjustment, 7(c)(2) delta.

BPA does not allocate 7(b)(2) industrial adjustment, 7(c)(2) delta to the PF preference rate because BPA has concluded that Section 7(b)(2) prohibits that allocation. Therefore, based on this conclusion, the 7(b)(2) industrial adjustment, 7(c)(2) delta is an amount not charged to the preference rate by reason of Northwest Power Act Section 7(b)(2).

Section 7(b)(3) of the Northwest Power Act expressly states what is to happen to such amounts. Any amounts -- and I quote: Any amounts not charged to public body, cooperative and federal agency customers by reason of paragraph 2 of this subsection shall be recovered through supplemental rate charges for all other power sold by the Administrator to all customers, end quote.

MR. ROACH: Don, isn't Bonneville's approach one that is attempting to harmonize that language and the equally specific language in Section 7(c) that the DSI rate is to be based upon the applicable preference customer rate?

MR. KARI: I believe the short answer, slight simplification to your question is, yes, but that does not address at all whether this language of 7(b)(3) requires an allocation of 7(b)(2) industrial adjustment, 7(c)(2) delta to surplus sales, and that's the thesis that I'm advancing today.

MR. ROACH: All right. Thank you.

MR. KARI: And the quote I just gave you, the referenced paragraph 2 of this subsection is, in fact, the familiar Northwest Power Act Section 7(b)(2).

BPA thus takes the position that Section 7(b)(2) prohibits the allocation of Section 7(b)(2) industrial adjustment, 7(c)(2) delta to the PF preference rate. If that is correct, BPA must, consistent with Section 7(b)(3) of the Northwest Power Act, allocate 7(b)(2) industrial adjustment, 7(c)(2) delta to BPA sales of other power, including particularly surplus sales.

In other words, BPA's rationale for not allocating 7(b)(2) industrial adjustment, 7(c)(2) delta to the PF preference rate requires an allocation of that delta to surplus sales.

If, on the other hand, allocation of the 7(b)(2) industrial adjustment, 7(c)(2) delta is not governed by Section 7(b)(3), which we submit that it is, BPA should nevertheless make a modification of 7(b)(2) industrial adjustment, 7(c)(2) delta to surplus sales. The absence of an express statutory requirement to allocate the 7(b)(2) industrial adjustment, 7(c)(2) delta amount to, for example, surplus sales does not and cannot excuse or justify an arbitrary decision to allocate essentially all of such delta to the PF exchange rate and none to surplus sales.

In any event, BPA certainly recognizes that the 7(b)(2) industrial adjustment, 7(c)(2) delta is caused by the 7(b)(2) rate test. So even if there is no express statutory provision governing the allocation of 7(b)(2) industrial adjustment, 7(c)(2) delta, it is logical to allocate 7(b)(2) industrial adjustment, 7(c)(2) delta in the same manner as BPA allocates 7(b)(3) trigger amount, because both are caused by Section 7(b)(2).

The only rationale advanced by BPA staff for not allocating 7(b)(2) industrial adjustment, 7(c)(2) delta to surplus sales appears to me to be that such allocation is not consistent with BPA's sequencing of its rate steps.

Pacific Northwest investor-owned utilities have shown that it is possible, and BPA has recognized that it is possible to allocate a pro rata share of 7(b)(2) industrial adjustment, 7(c)(2) delta to surplus sales using an iterative approach similar to the process that BPA uses to allocate 7(b)(3) trigger amounts.

Use of an iterative approach would, in effect, treat the allocation of 7(b)(2) industrial adjustment, 7(c)(2) delta essentially the same as the allocation of 7(b)(3) trigger amount. Such an approach would certainly not create a BPA revenue deficiency because the iterative approach takes into account the reduced secondary revenue credit that would result from the allocation of 7(b)(2) industrial adjustment, 7(c)(2) delta to surplus sales and, therefore, an iterative approach should be adopted.

So I'm going to move to another topic unless there's some questions on that one.

MR. WRIGHT: We can't wait.

MR. KARI: Finally, I would like to discuss the downward adjustment of CRAC amounts to be recovered from non-Slice customers.

To reflect a portion of the recovery of the cost to a portion of CRAC to Slice customers, BPA proposes the cost recovery adjustment clause or CRAC, which is a downward adjustment to residential exchange program benefits and an upward adjustment to the priority firm preference rate and other BPA rates but excluding the Slice rate.

BPA has analyzed how a CRAC needed to increase planned revenues for risk would be allocated across customers including those that receive REP benefits and has concluded that 20 percent of the revenue required by the CRAC should be recovered through reduced REP benefits.

However, PNRR is a particular cost that is not borne by Slice customers. Because PNRR planned revenues for risk is not borne by Slice customers, BPA's analysis of PNRR as the touchstone or the example for how to allocate CRAC costs is invalid for types of costs that are shared by Slice customers and that give rise to a need for a CRAC.

When a CRAC is necessary to address costs greater than projected or revenues less than projected that are borne by both Slice and non-Slice customers, then REP benefits should properly bear less than 87 percent of the revenue required by the CRAC.

In a parallel situation, the proposed industrial cost adjustment clause, BPA has developed a mechanism for allocating costs to Slice customers, the amount of costs that Slice customers should bear, and after that allocation, allocating 27 percent of the remaining balance as a reduction in REP benefits and 85 percent of the remaining balance to the non-Slice PF preference rate and other customers subject to the CRAC. A similar approach can and should be adopted with respect to the CRAC.

In sum, CRAC amounts to be recovered from non-Slice customers and reduced REP benefits should be adjusted downward to reflect recovery of costs causing the CRAC from the Slice customers.

That concludes my remarks. I'd be happy to answer any questions.

MR. ROACH: I thought you said it was going to be easier.

So the function of a CRAC is to recover, in part, is to recover costs that need to be recovered and that otherwise wouldn't be recovered. Wouldn't you agree with that?

MR. KARI: Absolutely.

MR. ROACH: And the Slice rate has been immunized, if you will, from CRAC because it recovers a percentage of whatever costs are. The theory being there is no need, therefore, to subject it to a CRAC; is that correct?

MR. KARI: That is not only correct, that is the very reason that Bonneville needs to take those costs into account. Take a really simple example.

There's a significantly increased amount of federal hydro system O&M in a year that triggers a CRAC. Bonneville says, okay, we're going to collect 27 percent of that amount from reduced REP benefits and we're going to collect 85 percent from applying the CRAC to non-Slice rates, and in a way that Mr. Bliven can explain to you that 85 percent and the 27 percent recovers the full amount.

But then next year, Bonneville comes along and says to the Slice customers, oh, by the way, you know, I noticed O&M was up last year. You're going to have to pay an adjustment. So Bonneville has already collected the full amount of the -- that cost through the CRAC, and then it collects more from the Slice customers. I don't mean to say this is nefarious; this is just an impact that needs to be recognized and corrected.

MR. ROACH: Different question. It's not subject to what you're talking about now, but let's see if I get the argument made in your brief right, and it concerns the allocation of the 7(b)(3) trigger amount to Slice surplus.

Is the long and short of what you're saying in there is if there wouldn't be a Slice, there would be more surplus that Bonneville should be allocating the trigger amount to and the result should be the same with Slice as without Slice in terms of the allocation amount?

MR. KARI: No.

MR. ROACH: All right. What are you -- I'm hesitant to say what are you saying. If you can, you know, succinctly state what your point is, I'd appreciate it. If it's not possible, I'll go back and reread the brief again.

MR. KARI: I would suggest the latter, but -- I would suggest the latter, but perhaps as an aid to -- a guide, Bonneville believes that when it allocates costs to a market-based rate, it allocates those rates, takes the reduced secondary revenue into account and runs an iteration such that, in effect, those iterated rates wind up paying maybe 20 percent of the 7(b)(3) supplemental charge that would be added if Bonneville just said, okay, the price is X. Now here's your $7-and-something supplemental charge adder.

Our point is that the Slice rate is a rate that is not set by market, and it is perfectly possible and capable and Bonneville should apply a separate 7(b) Slice adder, the same as it does for the PF exchange rate.

MR. ROACH: Thank you.

MR. WRIGHT: So a more general comment to this whole residential exchange situation. So, Don, your immense knowledge, lucid analysis of this is always impressive.

I would just say, though, that to all of you out there who represent policymakers, and this question is on residential exchange, if there is anyone who questions why we should settle this issue, I would actually ask you to use Don's testimony today as -- and again, Don, I don't want to pick on you because I could have picked on half a dozen folks in this proceeding or the last proceeding for this respect.

But I do want to appeal, once again, to all of the parties here that we need to find a better way to do this than the way we're going about this, and we're now at nine months since we concluded the last rate case, approximately, and I made this appeal to you all. We've made, at best, modest progress in terms of finding a way to settle this and we really need to find a better way to do this.

We will continue to do it this way as long as we have to, and we will do the best we can at it. But there has got to be a better way to do this than what we are currently doing, and I would say that at least for me, my patience is beginning to wear thin with respect to finding a solution at which all the party can agree to. And if we need to move with a smaller group of parties who are more willing to co-settle this, then we may need to try that, either in the best interests or the reason or I would hope empathy to put me out of my misery.

MR. KARI: Thank you.

MR. WRIGHT: That's it.

HEARING OFFICER PETRILLO: Thank you, Mr. Kari.

ICNU.

MR. SANGER: Good afternoon, gentlemen. My name's Irion Sanger. I'm the attorney appearing on behalf of Industrial Customers of the Northwest Uti lites. I'll try not to be down as far in the weeds as

Don was. I'll try to stay a little bit higher.

On wind integration issues, ICNU works with the Administrator to adopt positions identified in the joint party 11 brief filed by the Public Power Council. BPA should set a wind integration rate that fully recovers and identifies all the costs of wind integration and assigns those to the wind generators. ICNU would like to note that many of its member companies will pay this wind integration rate when they take service from the serving utilities, but ICNU believes the cost causation principles are the most important factor in setting the wind integration rate.

The goal for Bonneville should be to ensure the preference customers are not subsidizing wind generators, but at the same time, that wind generators are not overpaying for wind integration services. And the best way to do that is to follow Bonneville's established cost causation principles.

Now, there was a question asked about whether small wind generators should be exempt from the wind integration rate. ICNU urges the Administrator to adopt a wind integration rate that applies to all wind generators and does not exempt any wind generators, including small wind generators.

Exempting small wind generators would provide, ICNU believes, uneconomic or even irrational incentives to wind generators. They can size their projects in a manner that would be specifically designed to avoid the wind integration charge. ICNU has seen this in a state regulatory proceedings when there's been megawatt threshold established for cost rates or for competitive bidding guidelines. And wind generation is particularly suited to taking larger projects and sizing them in a particular way that might meet some arbitrary cut-off point.

I think that Bonneville -- if Bonneville believes it's a good idea to exempt a certain category of wind generators based on their size, there needs to be a lot of thought and process gone into it, and I know the state utility commissions have given this issue a lot of thought when establishing competitive bidding guidelines in PURPA regulations. And it's very difficult to do, especially in the wind area. So I would urge Bonneville to proceed with caution if you do believe this is a good public policy goal and something that we want to do.

There is also a question asked regarding how the Administrator should factor into decisions in this case the likelihood that the DSO 216 may not be successfully implemented.

ICNU recommends that BPA not lower its persistence level based on an assumption that BPA will be able to utilize DSO 216.

First, as has been noted, the DSO has not been fully drafted and it's not been completed. ICNU does not believe that it would be responsible for any party to weigh its rights to challenge the DSO until it's had time to review a fully drafted, fully vetted proposal.

Also BPA should not rely upon DSO's effectiveness to curtail operations when it's not even sure what the end language in the DSO is going to be. ICNU recognizes that some wind generators in this case have expressed a desire that they do not want to challenge the DSO, but they weren't able, and I don't think it would be the right thing for them to do to say they're not going to challenge it because they don't know what it's going to say.

There are many parties in this case which are wind generators which have not given any assurances whatsoever and avoided the issue. So -- or there are wind generators which are not a party to this case, so I don't think you can go on an assumption that the DSO will not be challenged. You can decide how you're going to use that.

Second, ICNU fears that if a low wind

integration rate is set based on the belief that Bonneville will be able to curtail those generators which do not operate at a 30- or 45-minute persistence level, that will unnecessarily politicize the wind integration issues.

In reality, ICNU believes that it is unlikely that all wind generators will be willing to accept curtailments when they actually happen, and ICNU also believes that it is likely that the Administrator will be subject to political pressures to not curtail those generators that do not operate at the appropriate persistence level. It could result in a practical situation where BPA is not curtailing wind generators and it is simultaneously under-recovering actual costs of integrating wind.

I'd like to move on to direct service industry issues. ICNU's simple recommendation, which is no surprise under the direct service industry issues, is the Administrator should exercise discretion and not serve the DSIs. Serving the DSIs will unnecessarily increase the costs to preference customers and cause job losses in their service territories. ICNU supports the brief of joint party 11 which was filed by the Public Power Council on DSI issues. The brief explains why the IP rate is too low, and both the Alcoa and the

Bonneville staff variable rate proposals are poor public policy.

In addition, adoption of the variable rate proposal, ICNU believes would be arbitrary and capricious because there's simply no evidence in this proceeding that the variable rate would equal the actual IP rate over the rate period.

ICNU would like to respond to your question about the three identified alternatives that you identified for DSI service regarding ICAC. ICNU understands this offer was made in good faith by BPA staff and it was intended to benefit preference customers. And it's not -- at ICNU, we recognize that, but we do believe that the way that it has been offered is a classic false dilemma for preference customers because it provides a number of options, none of which truly, in our view, benefit preference customers.

All three options include setting a certain amount of DSI costs in the base rate, which ICNU believes if you adopt an ICAC that you would hide the actual costs of serving the DSIs. The only ICAC that ICNU would find acceptable would be if Bonneville backed out all the costs of DSI service from the base rate and then the ICAC actually reflected the full cost of serving the DSIs. That ICAC would not hide the cost of serving the DSIs from preference customers.

ICNU would also like to address, and what was the main focus of our brief, Bonneville's overall PF rate. ICNU recommends that BPA use all available tools necessary to maintain rates at the current levels.

ICNU would like to express its appreciation, as many others have done, for Bonneville staff led by Ray Bliven. ICNU believes that they did an excellent job in working with the parties, although the initial proposal was outdated by the time it was actually filed. Once the proposal was filed, everybody, and especially the Bonneville staff, rolled up their sleeves and looked at all available options, and even though they were clear there were certain ones they didn't think the Administrator would want to do or that were not their own personal preferences, they worked with us to better design our ideas and come up with a lot of good options in keeping rates lower -- for lowering the rate increase and potentially keeping the rates at the current level.

ICNU believes that the rate case parties have successfully developed sufficient risk mitigation tools and cost reductions that allow the Administrator to maintain current rate levels without unduly jeopardizing BPA's ability to recover its costs.

BPA can keep the rates at current levels by relying on financial liquidity tools, additional cost reductions and removing the DSI costs from rates. However, if cost-cutting and financial mitigation tools are unable to reduce the rate change to zero or lower, then ICNU urges the Administrator to adopt step rates regardless of the level of the final rate increase, if there is one.

Step rates should be used to reduce or eliminate any rate increase in fiscal year 2010 because of the severity of the current economic recession that's facing end-use customers and the utilities that serve them. Most end-use customers and many utilities simply cannot afford a rate increase in fiscal year 2010.

Step rates are also important because they match the significant cost differences over the rate period with BPA likely facing higher costs in fiscal year 2011 than 2010.

The arguments raised by some parties against step rates ICNU simply believes have no merit. Paul Murphy from Cowlitz PUD I think successfully rebutted those. We would support the statements he made regarding step rates.

Simply if the Administrator decides to adopt step rates in the way that the Cowlitz identified in its brief, then the utilities that are against step rates really -- they have no reason to object. They can review the Administrator's final rate and adopt an average rate and go from there. There's no reason for the Administrator not to adopt step rates under the current circumstances facing the economy in the Pacific Northwest.

Finally, ICNU urges the Administrator to preserve the option of reducing the fiscal year 2011 rate if BPA's financial circumstances improve. Given the current economic conditions, the Administrator should retain the discretion not to impose a rate increase in 2011 if BPA's revenues exceed current expectations. This can help keep BPA's focus on cost reductions during the entire rate period even if BPA's financial condition is better than expected.

That concludes my prepared remarks. I'm available if you have any questions.

MR. NORMAN: So with respect to step rates, I guess I'd ask you the same question I asked Paul Murphy. If Bonneville were able to institute a customer-specific step rate where the base rates were not stepped, would that be responsive to your interests?

MR. SANGER: Could you provide a little more explanation of how that would work?

MR. NORMAN: We've had a flexible rate

provision in the PF schedule for a number of years. It gives us the ability to reshape rates for individual customers so long as the present value of their -- the revenues is unaffected, roughly. There's some other conditions. So I'm asking about application of that approach, although the posted rate may be not stepped. If we were able to step it for customers who preferred that, would be that an acceptable first step point?

MR. SANGER: In general, yes, ICNU would be supportive of any approach that allows the utilities to step their rates. I'm not certain if -- if the program's simply just a loan of money, then I'm not certain that would meet the utilities' end-use customers' needs, but if it is something that effectively mimics the step rates without actually stepping the rates, then ICNU would be fully supportive of that.

The substance of this is far more important than the form and how it works out, so if Bonneville has a creative solution to implementing step rates that is different from what everyone else has proposed, then I think that's a good approach to go down if it's more acceptable for Bonneville.

MR. NORMAN: Okay. Thank you.

MR. WRIGHT: So I read your testimony. I have to admit I summarized it in my head as keep the rates as low as possible including using a lower treasury repayment probability, do step rates and put in adjustment clause that can lower rates in the second year but not raise them no matter what the circumstances might be. And my reaction to that, candidly, is this is a business partner who doesn't really care whether Bonneville achieves cost recovery or not.

So my rhetorical question, actually, for you to take back to your clients, would be why should we stretch to work with you when, candidly, as a business partner, you don't come across as someone who worries about the things that we have to worry about, shares with us your problems and your interests, but really just doesn't show a lot regard for the kinds of issues that we have to address here in terms of the cost recovery? That being the number one issue that our rates are reviewed by or at the FERC.

You can choose not to respond if you want to.

MR. SANGER: No. I guess I would start -- I would start in the position that we believe that the cost recovery mechanisms that Bonneville has in place allow Bonneville to increase its rates if it is having problems with cost recovery. So ICNU's position is not that Bonneville should jeopardize its cost recovery probability, there are a mechanism which already can increase rates if there are situations in which Bonneville needs additional revenues.

And ICNU's position was not that Bonneville should set rates lower than what it needs for its cost recovery. Our position is that Bonneville should step the rates based on your determination, based on sound business principles what you believe your costs are going to be, and then if in the second year of that, your costs are lower or your revenues are much higher, then you don't increase the rate. But if your costs are as projected, then you would increase the rate in 2011. So we're not asking for Bonneville not to set rates based on the reasonable assumptions of what your costs are going to be.

So if we gave you that impression, then that was not the impression that we were trying to send. We didn't think that Bonneville should set its costs lower than what its costs are going to be.

MR. WRIGHT: But I think the thing that got me in particular was downward adjustment only in the second year. So what if things go bad? You're comfortable with upward adjustment there, too?

MR. SANGER: Don't we already have that built into rates?

MR. WRIGHT: I'm unclear whether you're okay with that or not, because we have dividend distribution clause in the rates now, too, and you seem to be calling for specific downward adjustment of rates, that unilateral right of the Administrator's decision to lower rates. Are you calling for something separate for what we already have for rates?

MR. SANGER: We are calling for something separate, and I guess the way we saw it was that the cost recovery mechanisms which are not challenging in this proceeding, the CRAC mechanism that the Administrator has that it was proposed by Bonneville, those were sufficient to ensure cost recovery. Now, if there is another -- so we were not going to pose another upward adjustment in rates because we thought that Bonneville developed its rate proposal based on upward adjustments and rates that staff believed were sufficient.

So that was our underlying assumption was that, one, you would set rates based on what you felt were reasonable expectations, and then there already are built into those rates the possibility that you can increase them. So, you know, we do not testify and do not put out that position challenging the CRACs that are out there or that basic structure of how the rates are set.

MR. WRIGHT: And is the dividend distribution clause adequate for downward adjustment?

MR. SANGER: I don't think dividend distribution clause has been used. I could be -- I could stand to be corrected, but we thought that giving you the unilateral right to not increase rates -- this proposal developed over time and at certain points in time, the proposal which I'm not certain how much of that actually got into the record, but there -- the proposal that we made gave you, the Administrator, the complete discretion whether or not to increase the rate in the 2011 period.

There were some proposals the parties talked about having a two-year rate period, two 7(i) processes, and, you know, ICNU did not propose a separate 7(i) process or anything along those lines.

So the proposal that we made on the 2011 rate we thought was providing you with a lot of discretion and was fairly reasonable and pretty far away from some of the proposals that were batted around originally.

MR. WRIGHT: Okay. Thank you.

HEARING OFFICER PETRILLO: Thank you, Mr. Sanger.

NRU.

MR. SAVEN: Good afternoon, Mr. Wright, Mr. Norman, Mr. Armstrong, Mr. Roach, Brian.

Thank you for providing this opportunity for Northwest Irrigation Utilities and Northwest Requirements Utilities to provide comment here today regarding the fiscal year 2010-2011 rate case.

So we start in rather difficult conditions. We have a gloomy regional economy. We have pending litigation regarding the FCRPS operations and the buyout that's quite contentious, and we're faced with a relatively difficult tiered rate methodology for everybody to get their hands on and to understand.

But in light of all of that, we've had a rate case. We're at 2010-2011 which I think has demonstrated a very strong and effective working relationship, particularly between public power and the Bonneville Power Administration.

The BPA staff is to be commended in particular for the tightening of the belt more than a couple of extra notches to achieve cost reductions rather than simply relying on new and creative financing mechanisms to avoid short-term financial problems. It's always difficult to cut internal services, especially when forces that cause that pain are beyond your control, particularly market conditions, river flows, et cetera.

BPA and the other entities funded by BPA help to achieve an additional $107 million during the next rate period of cost reductions, which is very helpful to us. It demonstrates that you are listening to what our concerns are, painful as this might be for you.

We particularly appreciate, Steve, you and your senior staff holding public meetings where the take-back that we got was you got the message. Paul got the message and everyone else did, and you worked accordingly.

So there are other reductions that we are interested in pursuing, such as augmentation costs along the lines identified in the NRU brief, removal of DSI costs from the revenue requirement, reduction in IOU costs consistent with the PPC testimony on 7(b)(2) and the fair allocation of the costs of wind forecasting variability to the generators pursuant to the PPC and the NRU testimony.

As the BPA rate cases become more complex, the issues are perhaps more difficult to deal with. Some of this, from our perspective, could result in opportunities for material changes that are not necessarily anticipated, and we would ask as representatives of load-following customers that the Agency work with us and Slice customers to ensure that the rate case outcomes do not result in unintended cost shifts between customer groups within public power.

The NRU initial brief is available for your review, and I won't restate it in detail here. I would like to thank Geoff Carr, Megan Stratman and Susan Ackerman for their hard work on this.

However, in this setting, it's probably appropriate for me as the CEO of NRU and the head of Northwest Irrigation Utilities to offer comments today, both with regard to Bonneville proposals and also proposals from other customer groups.

Many of these will be addressed in a technical matter when you see our actual comments responding to the draft Record of Decision. I heard your comments, Steve, with regard to issues of potential settlement of differences between, perhaps, public power, investor-owned utility customers, et cetera, regarding the exchange, and I would only comment that as one who has an interest in doing that, other parties should be kind of careful who they're picking on for purposes of what they're doing in the rate case and how that may affect their abilities to work constructively in the weeks and months ahead. But having said that, I am committed individually to consider actively pursuing those matters in whatever forum can be arranged.

There are some particular items I want to bring to your attention today. I've heard discussion about stepped rates, and admittedly, the public power community is divided on this issue. We're all concerned about economic recovery whether we live in large cities, rural areas or communities that are blessed with significant manufacturing and industrial loads. At the same time, our members are concerned about general rate stability over a reasonable period of time, and that's generally thought to be a two-year rate period.

NRU represents the interests of over 50 load-following customers located in seven states that account for approximately a quarter of all Bonneville sales to public power and a third of all of your customers.

We discussed the flat rate versus stepped rate issues at our last board meeting. Our members overwhelmingly supported flat rate for a two-year period, provided that the size of the initial rate increase is no larger than 5.0 percent. Our members like rate stability. When Bonneville changes rates, distribution utilities are often forced to change their retail rates, and a stepped rate creates opportunities for unintended consequences.

Being here this afternoon, I've heard questions posed to some of the other customer groups about perhaps one set of customers being treated with a flat rate and others with the stepped rate. I'm not opposed to at least continuing to explore that issue, but I hope at the end of the day everyone is willing to belly up to the bar in terms of their financial responsibilities for keeping the Agency whole, and I don't want to end up in a situation where in the second year, we have friction within the public power community about the ability of those who were paying less initially to pay more in the second year.

A second issue I would like to address is a proposal from Snohomish with a customer charge. We disagree with a customer charge. It's easy to understand perhaps why Bonneville's largest public customer would want to take a lot of Bonneville's costs and divide them equally among 135 customers. I have some difficulty grasping what small NRU members, such as Columbia Power or the City of Cascade Locks at less than three average megawatts would have to pay the same as Snohomish for a BPA customer charge. Perhaps I don't understand the customer charge because it's not been thoroughly vetted within senior management of the public power community.

This is a significant departure from current practices just when we're moving forward with a fairly complicated tiered rate design. Whether the proposal is based on economic self-interests or academic theory is unclear, but it's very clear that the NRU members would vigorously oppose a customer charge.

The next issue I would like to address is real-time crediting of secondary energy sales. WPAG is again proposing crediting for non-Slice customers on a quarterly basis for the value of secondary sales as opposed to basing rates on an estimate of the volume and price of these sales.

I applaud Terry and the WPAG members for their creativity. However, a proposal that initially raises the PF rate by six to eight mills at a time like this is, frankly, out of the zone of financial reality for my members. Given the state of our economy, I know that many NRU members are very concerned about just covering our current operating costs let alone immediately accumulating significant cash reserves that may be necessary to implement this proposal.

We're not opposed to examining this issue in the future for a rate period beginning after fiscal year 2011. However, there may be a question as to whether this proposal could be accommodated under the tiered rate design, and it may require overwhelming customer consensus before it can be advanced.

So in conclusion, it's good to see that public power and Bonneville are engaged on both great design and cost-cutting issues. We've come up with some fairly creative solutions to these problems.

I'd really like to commend, Dave, your staff for purposes of working with treasury to help mitigate our problems. We're looking forward to working with you in the future, both on a base rate design and an overall rate level that we are comfortable with and that you think is consistent with some business practices.

And more detailed comments would be included in our brief. And that concludes my comments. Be happy to respond to any questions.

THE COURT REPORTER: What's your name. My name is John Saven, S-a-v-e-n.

HEARING OFFICER PETRILLO: Thank you, Mr. Saven. We need to take another short break, ten minutes.

(Recess taken.)

HEARING OFFICER PETRILLO: I think the next party to argue is WPAG.

Mr. Mundorf.

MR. MUNDORF: Thank you, Your Honor. Wait for the panel to compose itself.

While they're doing that, my name's Terry Mundorf. I'm appearing at this moment on behalf of the Western Public Agencies Group and I was given a sign to read speak slowly and clearly, and I'll strive to do at least half of that.

Good afternoon. I'd like to express my personal appreciation for the panel actually still being here, even though you're one short of a full set. And there's a story -- that might sound like a throwaway line. It's not. I can't tell you how genuine it is.

First time I gave an oral argument in a state Supreme Court, quirky lawyer walked up to the podium, grabbed it firmly with both hands, looked at the panel. Three of them stood up and walked out. I hadn't said a word. I'm thinking what's going to happen when I start talking? So I'm clearly happy that at least four of you are still here. So thank you for that.

I'll add my personal and also my client's thank yous to the long list of thank yous you've gotten already from virtually everybody that's preceded me with regard to the way management and staff have dealt with a really tough set of circumstances, finding yourself with a rate case that's essentially been, say, outmoded - that might not be the right term, but you get my drift - by events that none of us saw coming has been remarkable.

This is the second time in a decade we've dealt with something similar to this. 2000 was analogous, different cause, California market meltdown, but the same basic effect. We had a rate case that now really didn't have much relationship to the reality that we were facing. Our reaction that time was I think not good. I mean we, meaning all of us, the Agency to some extent, the customers were all in denial and we stayed there for a while. We didn't react well or promptly. Once we did get going, I thought things went well.

This time completely different story. Early recognition, forthright, clear grasp of the enormity of the situation, and from at least my perspective, the acknowledgement that if things were left unchanged, 15 to 20 percent rate increase was just not something that was acceptable even to the Agency or to the customers or to the region as a whole. Remarkable. Well done all the way around.

Through our collaborative efforts and outside rate case efforts, a lot of tools were identified. At this juncture, we don't really know what size rate increase is going to be because there's a lot of things that haven't been redone that need to be redone in order to know that, but it is safe to say that regardless of where it turns out, it's got to be better than where we were before we started to sort of retool. And that's a good thing no matter where it ends up being.

So there are, I think, a number of steps, decisions, call them what you want, that are still available to the Agency to reduce the level of their increase, regardless of where that turns out, because we have things in place so we don't really know what those are all going to be. But there are some things that you can do that would be of help to your preference agency customers in what everyone acknowledges is a very difficult financial situation.

The first of these is to implement a stepped rate. I had a great argument put together that sounded like great minds thought alike. Most of the arguments have already been made so I'll try not to replicate them in any great detail. I would note that a stepped rate was proposed by Snohomish. Some would argue that might be reason enough to adopt it. I will not argue that, of course, but some might. Although we appreciate their solicitude in determining that all utilities in the region don't need a stepped rate, I think it's probably best for each utility to make up their own mind in that regard. I can tell you at least for what I'll call an exemplary customer of mine, client of mine, Clark, why it is that they are so bound and determined to convince you, hopefully through me, to implement a stepped rate.

They have been looking at a tough situation for some time. Since December their industrial loads have dropped by 20 percent. Their commercial loads have dropped by about 10 percent. These are significant losses of load and with the revenues that obviously go along with them. They have been told by their industrial customers that essentially any kind of rate increase is going to cause those trend lines to continue in a downward direction, which is obviously not good either for you or for Clark PUD, and that it will exacerbate and extend the time, the duration, if you want to call it that, of the economic downturn that they're suffering.

So they have real cause to want to avoid a retail rate increase. They're doing on their side what they can to avoid that outcome so they can give their industrial, commercial and obviously residential customers breathing space, and I've got a list of thing they've done just to be sure we're clear on that.

They have deferred capital. They have deferred programs that they would otherwise do. They have instituted a travel ban. They have a hiring freeze. They got 13 empty positions right now, which is for the size of the utility, not an in significant number. They've done a wage freeze including an approved increase for the CEOs who's going to forego that. And they have gone so far as to reconfigure their fuel supply for the River Road project by doing what they call extend and blend, selling back fuel current supply, buying at a lower price in return for buying at a higher price later on. So they're pulling out all the stops to try to find ways to help their community get through this.

What they're asking of the Agency is something that they don't feel is very extraordinary, and that is do something for them that they can't do, which is give them the lowest rate that you can for the first year. Regardless of where the revenue requirement turns out, a stepped rate does that. So that's what we're asking you to do.

As John indicated there's a fair number of public utilities that aren't interested in that option or at least don't favor it and maybe Paul a little bit. Paul asked the question, well, could we use the flexible PF? And that confused me at first, but I think I understand what he's talking about now, to achieve that goal. And the answer to the objective is an emphatic yes.

We're not particularly fussy about the method used. We're very much result oriented because right now we're in a tough spot. Clark's in a tough spot and the other utilities I work are in a tough spot, Grays Harbor, you know. Pick any of these ones that you want to. They've got bad circumstances. So this would help.

The twist I would offer to you is an individualized stepped rate that's computed sort of on a utility-by-utility basis I think is a lot of opportunity for mischief. Not that anybody would want to, but there's a lack of transparency. There's differing circumstances. Some people just get the formula and do the numbers. Others have special circumstances. Results can turn out wildly different.

Another alternative might be to post the average rate and a stepped rate as part of your rate -- final rates and give people, you know, two weeks, however long you have, to select it. Say, okay, I'm on Plan A. I'm an Plan B. That way, at least, we wouldn't run into the arguments that, well, my neighbor got this step rate and I got that stepped rate, and that doesn't seem fair somehow. So that would be a way to implement it, I think, that might solve the problem that really extends a helping hand to those that really do and are convinced that they need it on what I think are pretty compelling facts.

So that's not what I wrote down, but that's what I ended up saying about stepped rates.

Questions on that?

MR. ROACH: Terry, I can't remember, is Clark exchanging in the residential exchange right now?

MR. MUNDORF: They are not. They're in settlement. They have potential for exchanging when tiered -- in 2012, basically, when the tiered rates go into effect.

MR. ROACH: At least with Clark, we wouldn't have to worry about locating the steps for purposes residential exchange.

MR. MUNDORF: You would not. I'm not aware which, if any, publics are currently exchanging. I thought most, if not all, of them had settled out, but don't take that as gospel. That's just my recollection.

MR. WRIGHT: Can I -- just be clear, I am a bit surprised that the -- how important this is. Is it your proposal that there would be no revisitation of the rate for fiscal year 2011?

MR. MUNDORF: I think in our testimony and/or our brief, I can't remember which, there were a couple of parts to the puzzle. One part was to step the rates. Second part was to give the Administrator the discretion but not the requirement to revisit, if you wanted to, and move it down, if you wanted to, and to retain both the CRACs and the DDCs, so that sort of it was take the current cost collection structure and add to it a stepped rate which would have the ability for you to revisit it and do something with it if you felt it was warranted.

MR. WRIGHT: So candidly, the way that comes across to me is, we want you to keep the rate load today, keep all the CRACs and DDCs. And then next year we're going to lean on you to lower the rate, even if things are worse because you have the unilateral right to do so.

We're really not planning -- the way your testimony is, well, really we plan to pay the full cost across the two years, but implicitly in that it sounds to me like, well, maybe not. Thing are bad next year. We're going to lean on you for a lower rate.

MR. MUNDORF: I'm sorry. Maybe you weren't done. I apologize.

MR. WRIGHT: I was just going to say, this comes back to the concern I expressed with ICU about is this really a commitment to cost recovery?

MR. MUNDORF: I think I can state unequivocally with Clark, they're absolutely committed to the Agency staying solvent, fiscally sound and here for the long haul, so that's not even a question.

So the ability to move the rate down in the second year is not, in my mind, at least inconsistent with cost recovery, because I think the only reason you do that is if you had a bumper year and the second year were wildly over-collecting forecast numbers. If that weren't the case, I doubt seriously any entreaty would be effective and, frankly, my advice would be get on with life. We've got a tiered rate to implement.

When we were putting that together, it certainly wasn't envisioned that the notion that you would have the ability to recognize success in the second year was inconsistent with cost recovery.

MR. WRIGHT: Well, I think the reason I'm perplexed is for a business of Clark's size, basically what we're talking about then, given that the proposal works that way, is a simple cash flow problem, which can be dealt with in a variety of ways.

If you are expecting to deliver a certain amount of dollars to Bonneville over two years and it's a question of whether it's just a little bit lower the first year and a little bit higher the second year, I'm really not understanding why this is so important.

MR. MUNDORF: I think it's as simple as this, and that is Bonneville's costs -- Bonneville's power bill makes up probably the second largest single element in their cost structure, and they're in the process of squeezing all the other ones to the extent they can. You know, a two mill difference in the Bonneville rate in a year is important to them.

MR. WRIGHT: Even if it means it would be two mills higher in the second?

MR. MUNDORF: It would be. But that's not cash flow. I recognize that. What they're trying to do is help their customers by saying we're going to hold off on a rate increase as long as we can on the hope -- and it is that -- on the hope that the economy and you recover, so that when we do have to raise rates, if Bonneville doesn't end up rolling in money in the second year, that you'll be in a better position to accept and absorb that increase.

I'll grant you it's taking an action in hope of a better next year, but, you know, it's kind of like all we have to play with. Those are our options, and in these kind of circumstances, you try to use every option that you have on the table to try and help out because the economy and, you know -- and it's not the economy, this sort of gray thing that wanders in. It's companies with people who talked to the manager. These are real people and you can see they're really suffering. Businesses are closing.

The PUD is sort of doing at the local level what Bonneville tries to do at the regional level, which is helping everybody they can. This is another way they can help. Just like leaving 13 positions unfilled, it's not a boat load of money, but it's what they can do, so they do it. Hope that helps.

MR. WRIGHT: Yes. Thank you.

MR. MUNDORF: Good.

There are, in addition to the stepped rate, some discretionary decisions that are embedded in the -- sort of the case as it now stands that have the effect, I think, of negating a lot of the good work that was done in the cost control and liquidity tool area, and those are in no particular order of importance the allocation of 7(b)(3) surcharge amounts to the secondary, the decision on DSI service -- what's No. 3? -- the decision to delay the repayment of the look-back amount for PacifiCorp and Avista.

Given the time of day, the lateness of the hour, the time you've been here, I'm not going to go through the arguments that are already in the brief. But the bottom line of those three decisions is to essentially increase either the rate or the cost of power in the context of the look-back repayment amount, somewhere between 120 and $160 million a year for the rate period. Those in large measure -- undue isn't the right term, but they counteract a lot of good work that was done in other areas throughout the rate case.

The reasons why we think those decisions ought to be reviewed and reversed are in our brief. You can read them. But I would urge you to give them serious consideration because they -- those decisions wore against a lot of what was done to everyone's benefit through the cost review process and the very good collaborative process that we had with the staff.

Am I running out of time?

The last topic I want to touch on is the questions you posed with regard to the DSI and in particular -- DSI service. I guess it wasn't really a question. It was please make an assumption and then answer the question and the options available. So my first task is to make sure that you clearly understand public power's position on service and DSIs.

MR. WRIGHT: You can be sure about that.

MR. MUNDORF: Just wanted to test whether the answer to that question would be the same now as it was a half hour ago, so I won't.

The second is you gave three choices with regard to the operation of the ICAC, as we call it, and I would very much endorse the comments that Paul Murphy made a little bit earlier with regard to single cost collection mechanisms. I think they've had somewhat of a checkered history and I'm not sure I would -- in fact, I would not recommend them as a way to establish revenue stability, particularly one that takes a cost of risk, I guess you'd call it, from one class of customer and shifts it over to the other. Most of your adjustment clauses work in quite opposite fashion. They take a generalized cost of risk and make sure that it is spread generally, so this one really works in a counterintuitive fashion.

But more to the point in terms of which of the three options we'd recommend, I think we would go with Option 4, which is one that somehow got left off the list. I was surprised to see its omission. And that would be the risk of serving the DSI should be treated pretty much in the same fashion as risk that you incur in serving us is treated. When Vern identifies a risk, and he's been pretty good at doing that, the cost of that risk is put in our rate.

If there's a risk cost associated with serving the DSIs, probably ought to go to the DSI rate. Good place to put it, and it lines up the benefits with the burdens of service. So that would probably be the option, if it were available to choose, that we would choose. Let me see if I've forgotten anything particularly telling.

Yes. One last thing. One of you asked Mark Thompson earlier today about the rate case process. He had some comments in his brief and I think in the testimony, as well, about how the rate case process ought to be perhaps reconsidered or modified. We also add comments to that regard, perhaps even more pointed than his.

In a large measure, one of the reasons why we're kind of facing the dilemma of how do we redo a case after events have caught us short and have made the case that we prepared less than topical, is the duration, the time and length it takes us to actually prosecute a case from start to finish. It's probably close to a year, rough numbers. That's point one.

Point two is that the nature of our process is really litigious in nature and what we're needing, I think -- and that's necessary because we have to establish a record for appeal, but it has predominated the process to an extent that it has gotten in the way of collaborative problem-solving, which is really where we do our best work, and if this case isn't an example of it, I don't know what is.

So to me, what we need to do very seriously is consider ways to shorten the duration of the rate case. And there's a couple thing we ought to look at. How do we get the record established for appeal in a much more expeditious and prompt fashion? Do we really need to run all the studies we run in the way run them? Can we find a way to get a case done from start to finish in six months so that we're not always finding ourselves trapped by circumstances that we didn't foresee? So those are my specific thoughts. I probably voiced something similar to you in prior cases.

Finding time to do something that's of prospective value is always difficult. I'm hopeful that in the process of implementing tiered rates, we can find time to consider doing something like that because I think it would be to all our benefit if we would.

And that's all I've got to say.

MR. WRIGHT: Let me make sure I understand. Your Option 4 is -- I think it is charge the DSIs marginal costs instead of the molded costs?

MR. MUNDORF: I don't believe that's correct, but I'll be corrected promptly if I get it wrong.

I believe the ICAC collects from preference customers as proposed on a monthly basis the difference in revenues that forecast actual, based on differing levels of DSI load. It's not sensitive market price, power sensitive. The DSI load actually places on Bonneville compared with what you forecast in the rate case. So that's the nature of the risk.

What I'm suggesting is if you think that risk, you know, sort of equilibrates over the course of a year, the amount of PNRR, for lack of a better term, that Vern would be put in the rate would be fairly modest. So I don't believe it's equivalent of charging a marginal cost.

MR. WRIGHT: So without having thought through your Option 4, let me assume for a second there was no Option 4. I think what I heard you say is of the three options, you'd choose one that doesn't have an ICAC.

MR. MUNDORF: Yeah, we -- yes.

MR. WRIGHT: That's what I thought.

MR. MUNDORF: If I say anything other than that, I'll probably be lynched when I meet with my clients later this week.

MR. WRIGHT: I just want to make sure. I was trying to think about let's shorten the duration of the rate case. This rate case started in February, so that's -- there's something wrong here because I'm counting five months and --

MR. MUNDORF: So I count as the rate case when your staff starts cranking up the models and machinery to put the initial proposal together, because that's part of the rate case, too, because we have workshops with those folks and they're good. I'm not being critical. I'm just observing facts. We have workshops with them. They show us results. They show us issues that they've identified through this process. A great deal of very good work gets done before there's any initial proposal.

And I guess what I'm saying is we do spend five months doing the lawyer dance and the data request dance and the motions to strike dance and all that sort of stuff, and mostly good work happened October, November, December. So somehow the formalistic part, what I refer to as the Kabuki theater part of the process has sort of overwhelmed the analytical decision-making, grappling with issues part of the case which happens not entirely but to a great degree before the initial proposal even comes out.

MR. WRIGHT: So you like that part, the early part?

MR. MUNDORF: I absolutely like the early part. I'd like to be able to sit down with these people, even Don occasionally, and identify issues and try to talk them through. Once you start, you know, lobbing motions back and forth across the abyss, the ability to problem solve, even understand clearly what the other parties are worried about, diminishes greatly in my opinion.

MR. ARMSTRONG: Having been involved in one or two rate cases, that sounds familiar. In most every rate case, there's a plea to streamline the process and the constraint always comes down to the formal Kabuki that goes on after all the real work is occurring. So none of the parties to date have been willing to waive any of their rights, any of the time required to go through the steps. Discovery is one of the huge processes that has to occur.

What is different now than all of the prior rate cases that would allow us to think we can actually shorten this process, do you think?

MR. MUNDORF: I haven't been doing this nearly as long as you have, Dave. I thought I'd get a modest titter out of that one.

I agree with you that there have been, I can probably count, three faint attempts to try to really take this issue on and say, okay, what are the elements that we need? What are the ones that we do because we keep doing them over and over again? And I'll agree with you further that parties, myself included, being a lawyer would be very cautious about waiving rights that others don't necessarily waive.

What we haven't done is sit down as a group, much like we've done with the TRM, that was a real problem-solving exercise. First, we make something up and then we try to solve the problems that we created by making up. We have not sat down and said what are all the thing we need to do? Do we need to do them? How do we do them? And then look at them as a package and say, okay, in this context, if everybody was stuck with one round of data requests. Okay? We haven't done that.

So nobody's had the opportunity to evaluate what you described as a waiver of rights in the context of a package that everyone, if not support, can live with and all the rules they will have to deal with.

So I'm not sure it's being given a fair trial. What we have lacked, I think, is the time to do it, frankly, because I think it would be time-consuming. So that's all I have --

MR. WRIGHT: Thank you.

MR. MUNDORF: -- on that topic. I'm going to change my coat and come back.

MR. WRIGHT: Thank you.

HEARING OFFICER PETRILLO: Thank you, Mr. Mundorf.

MR. MUNDORF: Thank you.

HEARING OFFICER PETRILLO: Slice customers.

MR. MUNDORF: Hi. You probably don't recognize me, but my name is Terry Mundorf still, and I'm here on behalf of certain of the Slice customers.

As you probably noted from the briefing, all of the Slice customers joined the brief and, however, I don't work for all the Slice customers, so if there's any of the Slice customers that want to take a minute or two of my time to state their point of view since they all joined the brief, I certainly wouldn't have any objection to making that time available.

I just wanted to hit on two very brief points with regard to the Slice issues. One is the interaction of the Slice true-up, how it currently functions and the planned net revenue for risk. And the other is the proposal by the industrial utilities to charge the Slice customers at least twice for the 7(b)(3) surcharges, the best that I can tell, maybe three times, hard to tell for sure.

With regard to the Slice true-up, as you are probably aware, the true-up is calculated by comparing the average revenue requirement for the rate period, which could be five years or two years, to each of the individual actual expenditure patterns for a year. So there's a possibility of getting some mismatches there. And what happened in this case was as a consequence of that comparison. Bonneville staff noted that the planned net revenue for risk included in the non-Slice rates increased just because of the way that Slice true-up operated. Clearly a result none of the Slice customers intended and I'm pretty much certain the non-Slice customers didn't intend it either.

The problem essentially went away when the staff moved some amortization around and then we got the line of credit with the treasury and essentially the whole problem sort of, not went away, minimized itself to a point where no one needed to spend a great deal of time on it.

However, the Slice customers have discussed this and are of the view that there is a probability of this PNRR effect occurring in the future and probably not zero, and we don't intend to cause that kind of problem. We don't want to have PNRR for non-Slice customers increased.

So what they are interested in doing after this rate case is exploring with the Agency a way of ensuring that the true-up under the TRM going forward is done on an annual revenue requirement to annual actual expenditure comparison as opposed to using the average.

We think this will eliminate the likelihood of having the nefarious PNRR impact on the non-Slice customers. It will eliminate their worry about moving amortization around to make sure that the PNRR effect goes away. It will just put that issue to rest.

The reason why the averaging was used in the first instance is because there were five-year rate periods and there were concerns about the Agency moving costs around and triggering true-ups and that sort of thing. With a two-year rate period memorialized in the TRM, that risk I think has essentially been eliminated. So this shift would not only serve the interests of the Slice customers, but also hopefully help assure the non-Slice customer there's nothing funny going on and that kind of thing won't occur in the future. So that's kind of an offer to work on that prospectively to get an issue off the table in order to shorten the rate case process.

The second topic I wanted to touch on was the proposal to impose the 7(b)(3) surcharge on the Slice rate, and I want to start with the following proposition. It's our belief that the approach to the allocation of the 7(b)(3) surcharge to surplus as proposed by the staff is correct. It's the right way to do it if you're going to do that. Might disagree with the legal underpinnings of it. Mechanics are good.

MR. ROACH: You could have just stopped.

MR. MUNDORF: Your smile was to broad. I'm sorry. Had you had your poker face on, I would have flown right by that.

So the mechanics they got down. We'll differ about the legal basis later on. And we believe that the method they have implemented results in the same outcome that would be achieved were there no Slice rate at all. So we think it's absolutely on par the way it should be. We do not recommend changing it.

We think the proposal to impose directly a 7(b)(2) surcharge on the Slice rate double charges them and it, in fact, would require Bonneville to impose directly on a PF rate a 7(b)(3) surcharge, and if we all recall, the 7(b) rate -- I'm sorry -- the PF rate is the rate that's supposed to be protected from 7(b)(3) surcharges. So it would be a pretty far stretch of legality, at least in our opinion, to put such a surcharge directly on the Slice rate, particularly when there's no need to do so.

MR. ROACH: Terry, I was mulling over what Don said, and I don't want to cause Don to get up and protest that I've got it wrong because I may well have it wrong. I think I heard him saying, well, it's not a market-based rate so you have the ability to add a surcharge --

MR. MUNDORF: Yes, he did. Or I heard that.

MR. ROACH: -- to the rate. And implicit in that is the notion that if we were selling surplus to the Slice customers, they would -- I'll make this leading -- they would be so foolish as to pay more than other secondary purchasers would be paying. It doesn't make a lot of sense to me. Does it to you?

MR. MUNDORF: Did his argument make a lot of sense to me? No. And I have read the brief. But having said that, I think it's wrong as a general proposition.

The secondary that is made available to the Slice customers implicitly is market price limited because they sell it in the market if they don't use it to serve load, which means the direct result of that argument is if you accept the fact that the Slice customers can't get anything more than market for the secondary they get on their Slice, that which they don't use to serve their load, then the consequence of putting a 7(b)(3) surcharge onto that is to, in fact, apply it to the requirements portion of the Slice product. So you end up basically putting a 7(b)(3) surcharge on that portion of the Slice product that serves requirements load. And I got to tell you, we think that is just beyond the pale in terms of statutory supportability.

That's all I have to say for today, unless someone else wants to hire me to argue their case.

MR. WRIGHT: Thank you.

MR. MUNDORF: Do appreciate the opportunity and the attentiveness at this late hour. It's remarkable that I have four out of five of you left. Thank you very much.

HEARING OFFICER PETRILLO: Thank you again, Mr. Mundorf.

APAC.

MR. BROOKHYSER: Thank you, Your Honor. Good afternoon, Mr. Wright and gentlemen. My name is Don Brookhyser and I'm appearing for APAC.

I want to respond to two points that were made in other parties' briefs and also have been discussed here today.

The first is Idaho Power's argument, and I'm quoting from their brief, that BPA need not and should not accept as fact that the look-back amount is an obligation of Idaho Power. BPA decided in its ROD in the WP-07 case what the look-back of Idaho Power was. That's a decision that's binding on the Agency until it's changed either by -- modified by a subsequent ROD or by an appellate court, and your decisions in this case have to be bound by that. So I think it's improper to suggest that that obligation should be ignored.

Idaho Power also argues that the scope of the consideration about Idaho's -- Idaho Power's participation in the residential exchange program is limited to the period of this rate case. I disagreed with that to the extent that it seems to me the Administrator in rendering his decision in this case looks both at the facts as we know them with regard to this rate period, but also all the reasonable projections going forward, and at this point, the projections regarding Idaho Power's participation in the residential exchange program are that it will not in the foreseeable future or within the future that was modeled in the initial proposal.

That leads me to the broader point that compared with the WP-07 case, in this case, the uncertainties or the issues about collection of look-back amount have become more uncertain and have been -- have moved to the disadvantage of the preference customers. There still is no plan to collect from Idaho Power. The collections from PacifiCorp and Avista have been delayed or the completions projected to be a later year. And the uncertainties that we discussed in the

WP-07 case have simply become more acute.

APAC urges the Administrator to, first of all, relax the 50 percent principle or goal of repaying the REP benefit -- or paying REP benefits to the IOUs to provide greater certainty that the preference customers will be repaid within the seven years. And further, to provide for some plan to start collecting from Idaho Power.

The second issue --

MR. ROACH: If I could, let me explore with you a little bit about APAC's view of the current residential exchange program. As you know, the statute Section 5(c) of the Pacific Northwest Power Act structures the exchange. Congress chose to structure it as a sale by the utility to Bonneville and a sale back by Bonneville to the utility, and the utility has to file its ASC with FERC. At same time, the benefits of that transaction are to be flowed back to the residential and small farm customers. It doesn't go to the shareholders, and the legislative history is certainly full of statements basically about sharing the value of the system.

So I just want to get a handle on, you know, my perspective on this and I want to see if you agree. This is not entirely a commercial transaction. It's not entirely a public benefits transaction, but it's really something that it sort of straddles both. It has elements of a commercial transaction, but it also has elements of a, you know, public benefits type program.

Would you agree with that?

MR. BROOKHYSER: I think I would. And as I was listening to your question, it occurs to me that because of the repayment mechanism that was developed in WP-07, we've artificially put together, melded the REP benefit payment process with the repayment of this look-back amount. And so that then leads people like me to talk about reducing REP benefits. And perhaps the better way to talk about it and I think it's consistent with the policies which you're talking about is the REP benefits are owed to the utilities, but the utilities owe something in return to BPA to be repaid to the preference customers. The way in which we've chosen or the Administrator has chosen to do that is to reduce REP benefits. It can be done in other ways.

So I think the policies that you're talking about are legitimate and need to be reserved, but at the same time, some process for repaying the look-back amount has to be pursued.

The other issue that I briefly wanted to touch on was the comment made in the brief of the Pacific

Northwest IOUs, joint panel 1, I believe, in which they characterize APAC's argument and its testimony that -- in rewriting the 7(b)(2) test, they were proposing conservation be included at no cost, and that's simply not correct. This argument was made in the WP-07 case and the response is the same.

When Mr. Wolverton ran the 7(b)(2) test, the costs of existing conservation programs are included in that 7(g) amount which is first deducted from the amounts or the costs in the program case. And so the costs or the revenue requirement to fund the conservation programs is already there, and the arguments we're making about how conservation should be treated do not eliminate or remove that revenue requirement.

Thank you. Those are the comments. If you have no questions, thank you very much.

MR. WRIGHT: No questions. Thanks.

HEARING OFFICER PETRILLO: Thank you, Mr. Brookhyser.

Oregon Public Utility Commission.

MS. ANDRUS: Good afternoon, Panel. I am Stephanie Andrus here on behalf of the Public Utility Commission of Oregon.

I'll start my comments by echoing those that have been made previously, and on behalf of PUC, we thank the staff for the professionalism and that of the counsel. They're invariably willing to listen to our inquiries and respond when they can, and we found them to be very helpful and invaluable.

My comments today intend to, one, emphasize a piece of our testimony and also provide clarification on a point regarding the correct interpretation of the Power Act. The piece of testimony I would like to emphasize is that the Public Utility Commission believes that the current 7(b)(2) methodology, implementation methodology, can be punitive to exchanging utilities, and it can be punitive in circumstances when BPA projects that the ASC of exchanging utilities will be escalating during the rate test period at a relatively rapid rate. And these projections ultimately will have the effect of significantly lessening the amount of residential exchange benefits that will be a given to exchanging utilities.

Now, I think this effect is, I think, an artifact - if that's the right word - of the fact that the 7(b)(2) rate test period is six years but the rate period is two years. And I think another way of saying this might be that the problem is an artifact of the fact that the 7(b)(2) rate test trigger, which is based on an analysis of six years of data, is used as the rate protection ceiling for purposes of allocating 7(b)(3) costs for the two-year rate period. Because of that temporal mismatch, the -- and unadjusted 7(b)(2) rate trigger doesn't necessarily provide an accurate measure of what's the appropriate level of rate protection.

It appeared that the BPA staff's testimony in response to our proposal to alter the implementation methodology, their response, I guess, rejecting our proposal, it was based in part on their conclusion that 7(b)(2) mandates that the rate test trigger be used as the rate protection ceiling. We disagree with this interpretation.

7(b)(2), I'll read it, I think, for my ease, Section 7(b)(2) requires that projected amounts charged to preference customers may not exceed in total during any -- says year, I'll use the word rate period -- plus the ensuing years -- ensuing four years -- an amount equal to the power costs for general requirements of such customers if the Administrator makes five specific assumptions.

It's summarizing that essentially -- well, the key words, I think, for purposes of my discussion are may not exceed in total and during any year plus the ensuing four years. So essentially the rate protections which preference customers are entitled is that their rates over the rate period plus four years is no higher than it otherwise would be given those five assumptions.

However, whether preference customers are getting that particular level of protection under the implementation methodology is a question that is not necessarily addressed by the implementation methodology because the rate period is only two years.

So if ASCs or exchanging utilities are rising relatively quickly, preference customers are likely to be getting essentially more than the statutorily required rate protection. And the converse is true in fact if ASCs are decreasing relatively rapidly compared to other costs that are measured in the rate test.

The point of this discussion is simply to ask the Administrator and the panel to consider the PUC's proposal in light of the fact that it is not, in fact, prohibited by the Act. It may be something that the Administrator in its discretion chooses not to adopt, but, in fact, is not prohibited by the Act which appears to be a premise underlying the BPA's staff rejection of our proposal.

Also we ask that even if the Administrator were not to adopt our proposal, that you actually consider the issue that we raise. In fact, I think it was actually raised by APAC first, discussed in some degree by BPA prior to the rate case and then addressed by us in the rate case itself, which is that there can be a punitive effect felt under the implementation methodology, I think, given the disparity between the rate test period and the rate period, the temporal disparity.

That concludes my comments. Any questions?

MR. ROACH: So what is it that you're saying is punitive?

MS. ANDRUS: Punitive is -- and punitive, as I was waiting for my turn, I was thinking that might not be the best word, inequitable at the least, possibly punitive.

In December BPA provided interested parties with an analysis that showed that if you assume the ASCs are going to escalate in every year of the rate period at a rate of 6.8 percent, I think it's correct to say all other costs being constant, the effect on residential exchange benefits would be a decrease of 50 percent. I think that effect -- that is the effect that I would characterize as punitive. It's not a necessary effect.

The Administrator has discretion to make some adjustment to the rate test trigger for purposes of the rate protection ceiling, given the disparity in the period. The question is whether over a six-year period, whether the preference customers would be held harmless by, you know -- I know that's not the appropriate way to say it -- given those five assumptions and the implementation methodology doesn't truly answer that question given that the rate period is two years. You never get to the out years. So I think the Administrator has some discretion to modify the rate test ceiling.

I would assume in cases when BPA projects that there's going to be very little change in ASCs during the rate test period, it would be appropriate to use -- an unadjusted rate test trigger as a rate test ceiling. But when the ASCs are projected to increase relatively rapidly or decrease, it may not be appropriate.

And our concern largely stems from the fact that I think it's reasonable to assume that ASCs are on the increase, not on the decrease.

MR. ROACH: So I think what you're saying is that given the language of 7(b)(2) - and you didn't say this, but I'll say this, try to say this for you - and the fact that Section 7(a) simply says periodically review and revise rates, it doesn't say, you know, establish the rates every five years or every six years is basically you've got a problem in translating a six-year, adds up to six years for a two-year rate period, data into a two-year period and you're arguing that when Bonneville makes that translation, it should do so with a view to not penalizing or being inequitable to the IOUs due to the fact that, perhaps, out year IOU costs are increasing.

MS. ANDRUS: That's correct. That's correct. That's a correct statement.

MR. ROACH: Thank you.

MR. WRIGHT: So I think I understand the problem that you're talking about, and as you suggested in response to Randy's question, I think this was something the Bonneville staff displayed in some workshops in the last year.

I'm unclear on whether you ran through the proposed remedy that you suggest as to what the financial impact would be. What comes out of the back end? What kind of benefit levels would we be looking at if we adopted your proposal? Is that in the record someplace?

MS. ANDRUS: My argument today doesn't address our proposal. Our -- my argument today -- let me answer. My argument today gets, I think -- is a response to what appeared to be an underlying premise of the staff's rejection of our proposal. Our proposal -- I think my primary point today is we ask that you look at the issue and consider that an adjustment is likely appropriate to the 7(b) rate test trigger when you use it as a 7(b)(2) protection ceiling. That's my primary point. And our proposal, I have nothing really to add with respect to our proposal. The numbers are in our testimony.

MR. WRIGHT: And did you run it through different scenarios? What if ASCs are flat or what if ASCs go down?

MS. ANDRUS: Yes. If ASC's go down, residential exchange benefits goes down. And if ASCs go up, they generally go up.

MR. WRIGHT: In the current case that we're looking at, if ASCs being where they are, how much do benefits change?

MS. ANDRUS: My recollect is we did not run specific numbers. We ran hypothetical numbers.

MR. WRIGHT: I misunderstood. I thought you said that.

MS. ANDRUS: I think I did. I apologize for that.

MR. WRIGHT: I think the difficulty here you asked, particularly I think the request was of me to rethink this. And I think the challenges is I can see the problem, but I don't know what to do with it, because there's no remedy on the record to choose from. Moreover, if I tried to choose a remedy, I wouldn't know what the outcome was going to be, either in the current case or under a variety of different scenarios.

I can see why the issue might deserve more attention going forward, but I don't know quite what to do with it in this case.

MS. ANDRUS: Uhm-hum. I see that problem, and I would ask you to consider -- well, there are other aspects of this rate case in which numbers aren't finally decided. I would ask you to consider that I think the rejection of our analysis and our recommendations was based on an incorrect premise. And it might be unfair to penalize us for that incorrect premise or, I guess, unfounded rejection.

So I would ask you to consider and have your staff consider how you might implement our recommendation within the record that you have.

MR. WRIGHT: Okay. I understand what you're saying at least. Thank you.

HEARING OFFICER PETRILLO: Thank you, Miss Andrus.

Idaho PUC.

MR. HOWELL: Thank you, Judge, Mr. Wright and senior members of the administration staff. My name is Don Howell. I'm a deputy attorney general -- I'm the department attorney general and also general counsel of the Idaho Public Utilities Commission. I appreciate your attention. The hour is late. I will attempt to be brief and succinct and to the point.

I want to mention two things that are in our brief and both dealing with REP issues, and in specific, the 50 percent REP level versus seven years, and also touch briefly on the issue involving Idaho Power.

The Idaho Public Utilities Commission supports BPA's staff proposal that balances the goal of repaying the look-back amount within seven years while providing eligible IOUs at least 50 percent for the REP benefits for the two-year period of this rate case.

Setting the REP benefit at 50 percent for Avista and PacifiCorp will, of course, result in -- still result in 143.58 million in look-back repayments for this two-year period because Puget has agreed to increase its look-back payment.

We would note that BPA will recover nearly 40 percent of the total look-back amount, that's roughly $298 million, in the first three years of the seven-year period. We agree that recovery of the look-back amount should allow a reasonable level of REP benefits to residential and small farm consumers of the IOUs and that there should be, quote, stability and predictability of the REP benefits to the IOUs. Those are the fourth and sixth objectives laid out by the staff and the Administrator.

Turning to the Idaho Power issue, you've heard that Idaho Power is unlikely to be eligible for REP benefits in this case. However, simply because they're ineligible or not eligible to receive REP in this two-year rate period should not be construed to say that Idaho Power will not receive REP benefits in the future.

We agree with the BPA staff where it said that there are too many variables to quote, definitively conclude, end quote, for the next six years that Idaho Power will be ineligible to participate in the REP. It is simply to early to tell.

As the BPA staff witnessed, Mr. Young recognized on cross-examination, if Idaho Power adds wind or, for instance, a CCCT generating source to its resource stack, its ASC could rise.

As noted by Mr. Strong today and in our brief, Idaho Power has asked the Idaho Commission for a certificate of public convenience and necessity to construct such a combined cycle combustion turbine with an estimated construction price of $427 million. The commission has that docket under way. No judgment will be made probably to -- and construction, if authorized, would not be complete until after the two-year period. But that is an example of the type of heavy costs that the company is adding to its generation stack.

The bottom line is that it is simply premature for the Administrator to find in this case that Idaho Power will not repay its look-back amount.

And speaking of the look-back amount, the consumer-owned utilities are compensated for the delay because Idaho Power's look-back amount is accruing interest. Idaho Power is accruing interest at the highest T bill rate authorized in the case which was based on a 20-year T bill rate of 5.03 percent.

Finally, we also agree with the staff that it is unwise to withhold payments to Idaho Power in other transactions that it has with the Administration.

First, BPA has decided to recover the look-back from the future REP payments. We agree with that concept.

Second, withholding payments from Idaho Power would likely lead to expensive and time-consuming litigation.

Third, unsure outcomes of such litigation.

Fourth, it is unwise to do so while the look-back appeals are still pending.

And finally, Idaho Power may be eligible for future REP payments based upon the many future cost factors, not the least of which is acquisition of wind and the CCCT. These issues are not necessarily in the record, but the company has the relicensing of its largest hydro facilities, the Hell's Canyon complex. It is facing cap and trade consequences if legislation is passed. RPS standards which Idaho does not currently have. It has a major transmission project that is currently being processed through various state and local agencies.

Simply put, the Administrator does not need in this case to decide that Idaho Power will not be eligible for REP benefits in the future.

I believe Mr. Brookhyser is simply wrong when he says that Idaho Power will not receive benefits in, quote, the foreseeable future, end quote. I guess the length of time which is in one's foreseeable future is subject to change, but as we all recognize, Idaho Power had a large deemer status and that deemer status is, of course, still subject to resolution, and that is also one of the reasons why the REP payments is such a difficult issue for them.

Contrary to APAC's position, there is a plan to collect Idaho Power's look-back, and that plan is to recover Idaho Power's look-back from its future REP payments as those payments may be developed in the future years.

And with that, Mr. Wright, I would stand for questions.

MR. WRIGHT: No. Thank you.

HEARING OFFICER PETRILLO: Thank you, Mr. Howell.

PNGC.

MR. ERICK JOHNSON: Good afternoon, gentlemen. Appreciate your patience all day long. I will try not to take up too much of your time so we can get to the grand finale.

I want to incorporate by reference and not repeat all of the compliments that have been expressed by counsel before me for the performance of the BPA staff in this rate case. It has made a huge difference. PNGC thanks you.

I also want to complement the staff probably including Ray Bliven's team and your IT department for work that's been done to develop the electronic system that we now use for filing service of documents. Ray and Peter Burger might be surprised to hear me say this, but I think this is a remarkable improvement and a tremendous efficiency. It benefits all of us. Next time I'll try to handle data requests in a way that's more convenient for you. I apologize for the inconvenience, but I thought I was following the rules.

Mr. Wright, I want to respond to the question you asked about DSI service. I'm going to give you an answer, and then I want -- before you press me, I'm going tell you why I'm going to give you this answer.

We can't accept the assumption that there should be service to DSI customers at rates that don't collect all of the costs. We would feel we were betraying our retail customers by doing that. Below cost sales to the DSIs, as we argued in a brief in this proceeding, three pieces of testimony had offered testimony on various points pertinent to that. Since the start of this rate case, we filed three briefs in the 9th Circuit on DSI issues. I think you already know our position quite well. It simply doesn't comply, we think, with what Congress asked you to do.

In the rate case we've also asked you to reconsider your treatment of the IP rate under the 1985 methodology. We think you need to rethink things. Times have change quite a bit.

In briefs filed by many parties and in Mr.

Mundorf's description of the circumstances that Clark PUD is facing, you have heard your preference customers saying that things are very difficult. Very, very difficult and difficulty is growing. It's evident throughout the region.

I want to point out to you, though, that differences -- the impacts across the region are not uniform. I took a look at the Bureau of Labor statistics on unemployment figures. This is seasonably adjusted figures for April. In the U.S., 8.9 percent. There have been job losses in Idaho, Montana. Montana has a 6 percent unemployment level right now. Idaho has 7. State of Washington has 9.1 percent. In the Bellingham metropolitan area, which I think includes Whatcom County and Ferndale where the Intelco plant is located, I know they're concerned about unemployment there by reading the Bellingham Harold from time to time. They're at 8.5 percent as of April. Oregon, there is no county that has unemployment levels below 8.9 percent. Statewide it's 12 percent.

PNGC's members serve a fair amount of load for co-ops in the state of Oregon. I think most of the retail loads served by PNGC members is in the state of Oregon. I want to give you the numbers for three of the service territories, and these are just selected counties and it won't surprise you that I'm choosing some of the higher numbers. Vernonia in Columbia County where they've had difficulties from floods, including West Oregon Electric being flooded out of its own office twice in the last ten or 12 years. They can't afford to build out of the flood plain, 15.4 percent unemployment. Douglas County served by Douglas Electric, 17.6 percent unemployment. Crook County served by Central Electric Cooperative east of Bend, 19.9 percent unemployment.

Obliquely, in some of the materials that have been filed in this rate case and not so obliquely in other forums where we're engaged in a debate with Alcoa and with BPA, PNGC arguing on behalf of itself and preference customers have -- it's been suggested that we're maybe being selfish. I submit to you that there is a great deal more pain economically in some of the service territories that we serve than there would be if the Intelco plant were shut down in Ferndale and in Whatcom County the unemployment rose.

This should not be about substituting or favoring one set of jobs over another. We have made that point several times before, and we just respectfully request that you keep an open mind and mull this over.

Mr. Wright, you've expressed informally without communicating a decision in other forums for some time now that you have felt an obligation and a desire to do something for Alcoa. You shared your reasons, at least some of them. That candor, frankly, is welcome. We just simply have a fundamental disagreement about the lawfulness and the wisdom of providing the service to your DSI customers at less than fully allocated costs in these times. It's simply an unwise business decision we feel and it's inequitable.

Any questions for me?

MR. WRIGHT: No surprises there.

MR. HOWELL: Thank you.

HEARING OFFICER PETRILLO: Thank you, Mr. Johnson.

Alcoa.

MR. DOTTEN: Well, I am -- first of all, I guess I should introduce myself. I'm Mike Dotten for Alcoa, and I want to thank each of you for sitting through what has been now very close to eight hours of argument. I also want to thank you for a rate proposal that I think now accurately reflects what the statutes require of Bonneville.

In the past, I think Bonneville has tried to look for some shortcuts, not to achieve some unlawful purpose intentionally, but has looked for shortcuts.

And I think now particularly after the WP-07 supplemental case, Bonneville has correctly applied the statutes and I applaud you and your staff for going through the calculus to do that. That is reassuring to Alcoa.

For Alcoa, it's particularly important to have BPA in the WP-07 supplemental rate case apply the 7(c) rate guidelines in developing the IP rate and in following that methodology here. Because, in fact, in this case I think you have been invited to apply some form of triage to the Northwest economy. We don't think that that is necessarily appropriate, but if you really did, in fact, apply triage to the Northwest economy to determine who could survive and who couldn't, remember that 33 percent roughly of Alcoa's total costs are its power costs and no other customer in the Pacific Northwest region comes close.

And to Alcoa, the difference between market prices and the roughly 36 or 37 mill rate that would likely be derived from the IP rate is the difference between 36 and, say, 50 mills per kilowatt or $50 per megawatthour in the market over some period of time. The delta to other customers is more likely to be $1 on perhaps the low end and $2 on the high end, if you decide to provide service to all of your customers.

Now, it's characterized that this is making the decision to provide service to Alcoa and it is the cost of providing service to Alcoa, and we resist that characterization.

The 9th Circuit has made it clear that Bonneville has the discretion to serve Alcoa, but Alcoa's hardly a marginal load. It is one of your first customers, signed its first contract, according to Gus Norwood's history, in 1939 and has continuously been a customer since 1939. So it's not new to the region. It's not a new load. It's not a new operation.

I get the argument, the legal argument that's being made, which is if it's a discretionary load, you should look at it as a marginal load. But if you do that, and it's pretty clear the decision that you'll be making as the triage doctor or nurse, you would be doing away with one of the customers in the region.

The employment figures that you just heard are really troubling, but they should be troubling to all of us because it's an indication of how dire the economy is in general. The question is what's the logical response to that? Is the logical response to be not to save a customer to whom you know that there's a huge difference based on the decisions that you make? Or is the logical response to say, well, if unemployment is bad in the rest of the Pacific Northwest and particularly in some Oregon counties, we're going to get rid of this customer and hope that the others can survive seems to me not a very responsible or public-minded response. You may not be able to do anything about unemployment in the Oregon counties that were addressed, but you certainly can do something about the survival of pretty sizable employer in Whatcom County.

Now, preference customers have argued that they should not pay a rate with any service costs associated with what they claim is the result from the service to the DSIs. They begin with what I've already characterized as false premise that DSI service is incremental load on Bonneville's system. But the truth is preference customer loads have been growing at the very same time that the DSI loads have been declining.

So if we look at it purely from a public -- an economic good perspective, one could just as easily say that the preference customer loads are causing the increase in costs to Bonneville.

Now, Alcoa's response to that isn't to say charge the preference customers incremental costs of providing service to the growing loads. The response is to say what does the statute say is the appropriate rate under circumstances in which Bonneville is serving all of its customers.

The fact is that that question is answered by Section 7(c) with respect to the DSIs, and it's answered with respect to 7(b) for the publics. And it's true that the publics get substantial rate protection from Section 7(b)(2) of the Northwest Power Act and the surcharge that's applied under Section 7(b)(3), and Alcoa's acutely aware of that. In this case, it amounts to between 7, $8 megawatthour of additional cost.

So it's not a proposition that Alcoa is resisting because it costs more. It is, in fact, what comes out of the statute that Bonneville's obligated to apply and we, once again, I just want to say Alcoa applauds your adherence to the statute in the case.

Now, PNGC effectively concedes that Bonneville has correctly designed the DSI rate aside from the argument that DSIs should be required to pay the marginal costs of power. But it argues in its initial brief that BPA's, quote, methodology for making DSI rates for DSI service is about a quarter century old and, in fact, as you heard in PNGC's argument just moments ago, they suggested times have changed. But the statute hasn't changed. Bonneville still has to adhere to the statute in designing the DSI rates. We were all reminded of that.

It's an interesting situation because I think each of us, Bonneville, PNGC and Alcoa claimed some victory on the PNGC case, but I think the two things that we all were reminded of in the PNGC case is Bonneville has discretion. We argued you didn't have discretion. We argued that you had the obligation to serve the DSI loads. We didn't prevail in that position, but the Court clearly now has said that Bonneville has the discretion to serve that load, and secondly, that when it does serve that load, it's to do so at the IP rate, not some marginal cost rate. So we urge you in this case to adhere to the calculations that you made in the case.

Now, we have in this case proposed the adoption, again, of a variable rate that was pretty effective for Bonneville between 1986 and 1996. That rate worked extraordinarily well. We proposed one modification that I think eliminates most of the objections that you've heard to the adoption of this rate, other than it might help Alcoa and CFAC survive. Those arguments have mostly revolved around the question of do they, in fact, ultimately achieve the IP rate.

Alcoa's clear proposal was that there should be an adjustment mechanism and a long-term variable rate that would assure that Bonneville recovers the IP rate, and in addition, if during times when aluminum prices are high, the average rate exceeds the IP rate, that Bonneville should -- and its customers should obtain some of the benefit of that, meaning that effectively they would capture some of the profits associated with providing this adjustment mechanism for the DSIs.

We think that the variable rate is a reasonable response to the worst and, therefore, the unprecedented economic downturn that BPA is facing in its history.

MR. ROACH: Mike, let me stop you on that. Are you saying Bonneville designed the rate to do that?

MR. DOTTEN: I think you would ultimately have to decide it in a contract, but I think that Jack Spear's (phonetic) testimony suggests that there should be some upside to Bonneville, and in keeping some portion of this, and I think that would be subject to negotiation by contract. I don't know how you would know in advance how much that might be.

MR. ROACH: So how -- I'm trying to reconcile that with what I recall from your brief, which was that Bonneville did not have the authority to charge Alcoa a rate greater than the IP rate.

MR. DOTTEN: I think that as a base rate that is true. I think by contract Alcoa could surrender that advantage in exchange for obtaining the flexibility under the variable rate.

MR. WRIGHT: Let me make sure I've got it right. You're suggesting that on an expected value base, across the term of the contract that the rate in the contract could be structured in a fashion that it would recover more than the IP to, in effect, compensate the preference customers for the risk of variable rate?

MR. DOTTEN: More that it would be built into the true-up, so I don't know that it would.

The problem with the approach that was used in the prior variable rate is it was extraordinary complicated and it required Bonneville to make a number of forecasts. We tried to -- as we were talking about how to develop the rate, we basically said, well, there really isn't time in this rate case to go through all of the calculus that was done in the prior rate case. So how do you overcome the need for that, and we thought that having some look-back mechanism that was agreed to would achieve the same objective.

So I don't think on a forecasted basis you would do it -- you would necessarily attempt to do that, because you don't have to. At the end of the day, you would collect the IP rate based on a contract rate on behalf of Bonneville to collect the IP rate, and presumably some amount in excess of that assuming that aluminum prices are higher than the upper axis of the curve. But the assurance is there's a floor that would be the IP rate and then some upside potentially.

Now, the argument that the parties did not have an opportunity to respond to the variable rate I think is incorrect. Alcoa proposed the rate in its opening testimony. BPA presented rebuttal testimony on the subject and then surrebuttal. If the joint customers were correct in their position that the parties weren't offered an opportunity, then Bonneville would never be free to adopt a proposition proposed by any of the parties in a rate case. That makes a lot of sense economically and as a matter of public policy, because it would be novel and did the parties have an opportunity to respond to it.

I suggest that provisions of Section 7(i) are not so confining on Bonneville and, in fact, are intended to do just exactly the opposite which is to encourage parties to suggest to Bonneville alternative ways of achieving good public policy.

Now, the joint customer brief I think makes two contradictory contentions. First, BPA does not have sufficient information by which to adopt a variable rate, and then later that BPA should not open a proceeding to study the long-term variable rate over a long-time horizon.

Well, the second proposal defeats the first if their claim was legitimate that there was insufficient time to study the variable rate. Obviously, their objective is simply not to have any variable rate. 7(c) formula bases the DSI rate on the PF rate plus the typical margin. And that typical margin is based on the rate of typical margin charged by preference customers to their industrial customers.

Now, the joint customers have asked you to inflate that typical margin in this case by some amount, presumably adjusted for inflation, and their claim is that there's insufficient evidence in the record to support the .57 mills per kilowatthour, typical margin that Bonneville's included in the IP rate. But a little history may be worthwhile. After that claim was made, Alcoa sought through discovery to obtain information about typical investor margins. No one has better access to that margin information than McNeil (phonetic) and its members, and we were unsuccessful in getting answers to discovery of those questions.

So in the absence of Bonneville having superior information, I think it's pretty clear that Bonneville is safest, as a matter of judicial review, in keeping in place the industrial margin. One could just as easily argue based on much speculation that industrial margins have declined from the past because of arguments made by other customers like Alcoa to their preference customers who serve them, that they've got to reduce their margins because they're having trouble surviving at this time. My guess is those efforts have been made. Some of them have probably been successful. But as the record presently sits, I think you have no basis for adjusting the industrial margin.

In addition to recommending that BPA assume without evidence typical margins would increase, the joint customers also recommend that BPA include in its calculation of typical industrial margins a surcharge that includes the Washington State revenue taxes.

Well, first those taxes are not related to utility margin. They are taxes imposed by taxing entities to raise state revenues.

Second, they're not typical margins because they're charged -- not charged by states other than Washington to publicly owned utilities and nothing in the federal statute permits BPA to indirectly impose on the DSIs a Washington State tax as a surcharge above the typical margins that utilities collect for providing distribution service for their industrial customers.

At this stage, rather than go on, knowing that

I am the only thing standing between you and your dinner, I'd entertain any questions that you might have of me.

MR. WRIGHT: I've got a few actually. One of the issues, certainly for the preference customers, if there's an interim variable rate is whether, in fact, that rate will be collected if down the road Alcoa were to get into trouble of some kind. So there's been discussion of letter of credit and I didn't hear you address the letter of credit issue.

MR. DOTTEN: I think that is an issue that could be addressed in a contract. Based on your treatment of other customers who may be in similar financial situations, I think if you ask for a letter of credit based on the need for true-up, I think, you know, the contract negotiations, you could ask for that and it might be reasonable under the circumstances to do so. How large a letter of credit you'd need from a Fortune 50 company that's still in, you know, reasonable health because it's taken the actions it needs to, I don't know, but I think that's a matter for contract negotiations, but I think it is something that you have asked for before and Alcoa has given.

MR. ROACH: Mike, let me test that a little bit. So when we adopted the variable rate previously, the underlying legal rationale for that rate was based on the legislative history of Section 7(b)in the Northwest Power Act which affords the Administration discretion to design rates. The legislative history of Section 7(b) basically says that the rate directives govern the amount of money to be recovered from each class pursuant to a rate, not the rate design, and our approach when we designed the variable rate before was that the design of the rate assured that we would be recovering the amount of money that the Section 7(c) rate directive requires to be recovered.

You seem to be suggesting that, no, we don't need to do that in the rate. We can just leave that for a contract negotiation that other customers may or may not have input to.

How do you reconcile what I related in terms of the underlying legal -- the basis for the rate with your notion that we can just go off the contract on this very essential issue of the vehicle for assuring that, in fact, we recover the revenues we're supposed to recover from your client?

MR. DOTTEN: It is a reasonable concern. I think it's one that could be easily addressed in the tariff that simply says that any contract implementing this will require that there be an adjustment to assure that Bonneville collects the IP rate.

You can also, I suppose, look at the underlying purpose of the statute which was to assure that Bonneville collects adequate revenues from each customer and say to a reviewing court we've assured the underlying statutory objective. Either it isn't the tariff because you don't do what I suggested might be the alternative, or conversely, we have put it in the tariff and here's the contract. We've put it in the contract. The objective isn't mechanical. It's more financial. They want to make sure Bonneville will have adequate revenues.

MR. ROACH: Notwithstanding what people have said today about the rate case process, nonetheless, I would expect many of the same people here to say the rate case process does serve the function of assuring them input pursuant to Section (i) into those kind of issues.

MR. WRIGHT: I think your answer to Randy's question would also suggest that you would not object to placing a requirement for a letter of credit into the tariff.

MR. DOTTEN: Strikes me that there may be conditions where you want it and where you don't, so you could put in a requirement that if Bonneville determines that it needs it to be assured of repayment, it could do it. I don't know that you'd want to tie your hands in a tariff requiring it in all circumstances, but...

MR. WRIGHT: I'm going to ask you to speculate a little bit on behalf of your client, and to the extent that you're uncomfortable, you can talk to them about it.

I actually don't -- I'm trying to figure out where it's most valuable to spend time so I was surprised that Alcoa came in as late as they did in this case with the variable rate proposal. You're very experienced. As you say, you've been a customer of Bonneville's for a long time. You know these things don't happen quickly. You know how long it took to put the variable rate together the first time. I suspect that you had to know that the likelihood of getting to a final variable rate in this rate case, given the time you showed up, was extremely low, which meant that really we were confronted with the potential of doing something like this interim variable rate and a follow-on rate case of some kind.

Now, simultaneously this public meeting yesterday noticed as a rate case meeting, as well, that discussion of a contract, short term or longer term, different terms being discussed, et cetera, candidly, it is extremely difficult given the resources that we have to pursue these concepts simultaneously. Just we're agreeing and put in an interim rate, it has to be followed up with a long-term rate, and I think we both agree to that.

And moreover, this interim rate, in effect, what Alcoa -- if I was sitting on the other side of this, I think the way I would look at it, and you correct me if I'm wrong, that is this interim rate would basically be buying power and we'll tell you what the rate is later because it's subject to true-up and subject to establishment of the long-term variable rate.

Is there a prioritization process going on at Alcoa here about what's most important, and can we decide which of these things is most important? Because I have doubts, serious doubts, that we can pursue both of these simultaneously.

MR. DOTTEN: Candidly, I think we don't know. We didn't know when we got into the rate case at the beginning of the rate case how desperate things would turn. Aluminum prices were halved in a period of about three or four months. So I think Alcoa was trying to propose something that was familiar.

I think they'd like to have an IP rate that is predictable into the future, and because they presently have $60 power that they had to purchase under the monetary benefit approach, they're feeling stuck at the moment.

So the truth is when you're trying to survive, you throw out as many things as you can. And I know it's put you in a difficult position, and I recognize that it's taking a great deal of your and Bonneville's time right now to consider all of these things. And we're appreciative of that because we're trying to save 500 jobs in a plant that we think does important things in the region.

At this moment, I can't tell you what that priority is because I'd need to see what is Bonneville most inclined to do. A variable rate will work over a long period of time just by its nature because it means when aluminum prices are low, it doesn't mean we have to come back to you and ask for some interim solution. It's automatic. Worked pretty well in the ten years it was in place. So I think when we're struggling with this, developing our testimony in the case, we're seeing things are pretty desperate. What can we propose? We looked back at the variable rate and said it worked pretty well before. Don't have a lot of time to get it in place, and what's the solution to that and the solution we thought would be to assure that the recovery of the IP rate by some adjustable mechanism in the end that would assure that Bonneville was made whole as to the IP rate. We think that's probably legally required as well.

And then to sweeten the pot, if aluminum prices are great, we can afford to pay a little more for power. That seems fair and it sweetens the pot to the preference customers. It's an expectancy that they might have. No assurance of it. The assurances they could get repaid at the IP rate. So we were really struggling for alternatives.

I'm not sure that answers your question, but I think it's as much of an answer as I can give you.

MR. WRIGHT: Right on both counts. So I guess I would challenge you to have a conversation with your clients about this because we do have this problem. Once you went down the path of the variable rate and introduced it in this rate case, we're in ex parte, so you -- I think most people in the room know I don't particularly like the rules, but the rules are the rules and we abide by them. So there's no way to really have the conversation you just suggested about what's more likely. Yet I think the company's going to have to make a judgment about what's more likely, because the fact of the matter is if we keep trying to do both of these, neither one of them is going to get done in the time frame that Alcoa is asking for, at least. So somehow, some way you're going to have to think about how you make that judgment and make it now.

MR. DOTTEN: And I will communicate that immediately to the Alcoa folks, and I appreciate your letting us know that.

MR. WRIGHT: Okay. Thank you.

MR. DOTTEN: Thank you.

HEARING OFFICER PETRILLO: Thank you, Mr. Dotten.

Alcoa was the last party on our list for oral argument today.

Mr. Wright, does the panel have any final remarks before we adjourn?

MR. WRIGHT: I just want to thank the parties again for terrific work. It's a very helpful day for us in terms of working through these issues and being in a better position to better understand it. I really find the oral argument to be a particularly valuable piece of this case.

I will just note for the record that we didn't spend any time talking about transmission today because we have a transmission settlement, so there's some really good stuff going on on that side that should be recognized, at least. And with that I'm ready to close.

HEARING OFFICER PETRILLO: Thank you, Mr. Wright.

With that we'll adjourn this proceeding. And what we're going to do, as I indicated earlier, is to reconvene another short proceeding to hear comments from the participant that precipitated the question regarding wind generators. That would be the Oregon Trail Wind Farm, and I think I indicated to the parties that if they have any response to those comments, that they could respond, as well, on the record.

Is that acceptable to you, Mr. Wright?

MR. WRIGHT: Yes, it is.

HEARING OFFICER PETRILLO: So the formal oral argument proceeding is now adjourned. Can we just take a minute or two to get everybody situated here and then we'll reconvene the second proceedings.

(Recess taken.)

HEARING OFFICER PETRILLO: At this time, we're going to take some comments from Mr. Woodin on behalf of the Oregon Trail Wind Farm. Mr. Woodin submitted comments that led to the Administrator's question regarding wind generators.

Please proceed.

MR. WOODIN: Gentlemen, Mr. Wright, thank you for the opportunity to speak today. I realize that this is somewhat of an extraordinary opportunity and I thank you for it.

You've heard our comments in the past. We're here basically looking to generate discussion about an exemption for smaller than 20 megawatt projects. In Oregon and Idaho right now, community projects are basically 10 megawatt and below, that sell in the PURPA contracts.

There is a discussion at the federal level that may move that up to 20 megawatts, so you'll hear two numbers, why it is as it exists today is ten. But if we have conversation, I think we ought to be keeping in mind potential federal changes to 20.

There's a number of issues here and there are people that say, well, why should these smaller projects get breaks that we don't get? They should pay the same that we do. There's probably a couple cognizant reasons and a few ancillary ones. Probably the first one is that unlike the larger projects, our smaller ones sell in the PURPA contracts that are fixed price avoided costs. We can't pass anything on by changing the power rates. So when a new cost is put upon the smaller projects, they have to absorb them internally. Where they can, they will and where they can't, they just don't build the project.

The second issue is is that PURPA contracts are judged by the PUC to be firm-farm projects, so a lot of the auxiliary services, shaping, et cetera, for the larger project are really not required for the smaller ones because the power is basically sold on an as-is basis to the purchaser.

There is sufficient precedence of FERC, NERC and WECC where they define different power generation levels and they're pretty explicit about projects smaller than 20 megawatts. A number of them don't even track them in their system. Others have put in rules that pertain to the smaller projects to give them a fighting chance to compete against the larger more lucrative projects. So our request for consideration has got some pretty good precedence behind it.

Small projects really can't support a threefold increase in transmission costs. I've looked at the economics of a number of small projects, and in the early years while they're carrying a lot of debt, a lot of construction costs, they're lucky if they can see 100 to $200,000 of positive revenue. The proposed changes in a wind integration fees basically are at least that much or more and will push a lot of them right out of the picture.

We're involved at state and federal level to promote favorable policies for community projects. There's a lot of outreach from a number of states around the country, Oregon being one, Idaho being others, and Minnesota, Iowa, Massachusetts, to start to define at a federal level what these smaller community projects are.

The world is shaping up into two types of renewable. Wind by far the largest renewables are the large wind projects, and they will be the predominant renewable project in America for many years to come, and we support those. We definitely don't want to be in a cross position with them. But we want to make sure that there are also opportunities for the smaller projects.

Our organization represents small hydro, biomass, wave energy, geothermal and small wind and so we're very focused on policies that have unintended consequences that can damage these projects.

That is probably enough to be talked about for right now. I know that there are a number of questions that were asked earlier, and I'm here to address any of the issues that you're pondering.

One other comment maybe I ought to make is that in Oregon PUC and Oregon Department of Energy, we've been very focused on the potential for gaming the system, because any time any group gets a special consideration, there will be people trying to find a way to take advantage of that. And we would be glad to work with BPA to help come up with definitions that can give you some confidence that you've got some protection as to who is ineligible. I can think of a couple off the top right now. Like, for example, community projects have to be PURPA-based projects to get an exemption. If they're not PURPA-based, then they can pass their costs on like anyone else.

And there's probably other potential safeguards to narrow down the potential for gaming.

Questions?

MR. SILVERSTEIN: One question. Has there been conversation with the states about mechanisms to pass on the responsibility to the purchasing entity particularly if their balancing authority which would be either to cover the ancillary service cost obviously above the PURPA rate, or to telemeter the project into the purchasing BA so that they then take on the balancing responsibility rather than shifting those costs to other customers?

MR. WOODIN: One thing I didn't mention is that our organization is involved with a BPA grant that is looking for low cost solutions for these community projects to do telemetry. We're working with PGE and

Department of Energy and BPA, and our goal in that particular task force is to come up with a small cost effective telemetry system that can aggregate a number of small generators and pass that on to different control systems.

And also in the case of -- well, in the case of all of them, wind in particular, to be able to provide near real-time forecasting under the system on an electronic basis. So, yeah, we are looking at some of those issues.

The PUC and we have not been involved in any conversations since the last docket about who shares what cost where. The point at the last docket was clear. It was UN 1129 (phonetic). It was fairly straightforward that the PURPA contractors provided non-firm power and that the utilities received it, but there wasn't any more sophisticated discussion than that.

MR. WRIGHT: So if you had telemetry, does it solve the problem? Because the ancillary service needs --

MR. WOODIN: I don't have enough knowledge to answer that. I'm sure that the regulated utilities would say they don't want to bear the cost of shaping and firming. They just want to take it as-is and they'll deal with it. But I think that's a conversation worthy of probably more than me just standing up here right now. The concern we have is the additional costs of the wind integration taken.

MR. WRIGHT: So what are the size of the units that people are building?

MR. WOODIN: Well, again, they're based on whatever the current policy in the state is for community project, and right now it's 10 megawatts. So that could be nine 1.5 megawatt machines, four 2.5 and smaller. They're not all going to be 10 megawatt.

The other question I think I heard earlier today is how many are in the system. In the PacifiCorp system now wheeling through BPA, there's probably somewhere in the range of 70 megawatts with probably another 40 on its way. In the BPA system, I'm not aware of anybody that's on-line right now. There is in the transmission request and work that's being done probably somewhere between 70 and 80 megawatts. These are individual 10 megawatt projects that are -- a few of them are centrally located where they might share a common connection, but a lot of them are spread out over the state, mainly the northern interior of Oregon.

MR. SILVERSTEIN: Our information is there are three 520 megawatt requests in the Bonneville queue and

some smaller ones.
MR. WOODIN: I'm not too sure what they're doing over in Idaho. We're more an Oregon-focused organization.
MR. WRIGHT: So basically these are the same size units as an LGIA, individually, 1, 2 megawatt units.
MR. WOODIN: In some cases. There's some people actually looking at smaller than 1 megawatt turbines. It's difficult because they're not quite as efficient.
We still have to deal with the same light winds and efficiencies that the large projects do. The difference is that where PGE might put in a 450 megawatt system with multiples of turbines. A 10 megawatt project might only be four or five.
MR. WRIGHT: So Bonneville charges a per unit charge, and I guess I'm not clear on why size makes a difference as to whether the charge should apply or not.
MR. WOODIN: Well, again go back to how does the organization have to deal with the increased cost? If you add a cost onto a regular project that is selling on an open market, the price of power goes up slightly they pass it on. If you put that same charge on a PURPA project which has been a fixed avoided cost, they can't

pass it on. They have to absorb it. A lot of cases on these smaller projects, they cannot ignore the cost that's been proposed.

MR. WRIGHT: How often do these PURPA rates get revisited?

MR. WOODIN: Every two years. We're due for another review here this summer in Oregon. Idaho went through a review a little while ago.

MR. WRIGHT: I guess that would suggest to me this is a temporary problem that the Oregon PUC could fix or the Idaho PUC could fix if it wanted to.

MR. WOODIN: Well, the definition of avoided cost is pretty well defined at the federal level. And it does not include ancillary services for wind integration. It's basically avoided costs or calculations done by the utilities. In this case, in the Northwest looking at natural gas prices and then projecting out what a new facility would cost them.

Unless the PUC specifically said that they would integrate these new integration costs into the avoided costs, they're not there right now and it's very difficult to get the PUC to want to make major change to avoided cost.

MR. WRIGHT: So you're arguing for a permanent exemption?

MR. WOODIN: That's correct.

MR. WRIGHT: I have to admit, I'm not quite sure -- I can understand a temporary problem. I'm not sure if I understand a permanent problem, especially if basically we're talking about the same size units as have signed up for an LGIA. So Bonneville charges a cost per unit, then in effect it would be why should this particular turbine not have to pay for ancillary services and why wouldn't we end up with -- especially if it's a permanent, one why would we end up with 8 megawatts now but hundreds of megawatts in years. It's a significant problem.

MR. WOODIN: I understand that BPA wants to look at these in large sizes, 80 megawatts, 100 megawatts here. I don't see it that way. I see ten 10 megawatt projects that are separate LLCs with separate financial arrangements and separate financial needs, and the fact that there's three of item or ten of them doesn't change the economics of those projects. So I don't see it as an aggregated sum and, therefore, we ought to treat them differently.

There are going to be community projects in the Northwest. We're not going to go away. The issue is is there going to be policies that will allow them to exist or will there be policies that basically snuff them out before they get started?

MR. WRIGHT: So I think you were making an argument that because they're small contracts, pass-through projects that they don't create the costs and, therefore, they should be exempted from the cost for that reason.

MR. WOODIN: Well, I'm making several arguments. One is the economics are different than the large projects; and two, that right now the definition from the Oregon Commissioners of the PUC are that they are non-firm power sales and they are not shaped or sent to the utilities with any special extraordinary treatment.

MR. SILVERSTEIN: Unfortunately for us as a balancing authority operator, we don't have any exemption, say, for meeting our liability standards for a firm or non-firm generator, so I don't see the connection how their non-firm status impacts our obligation as a balancing authority to bring the necessary reserves. And since these projects are located geographically in the same area as the larger projects, they electrically perform the same way, and my guess is their contribution to our reserve requirement would be pro rata exactly the same as a large project.

MR. WOODIN: If in the next five years or ten years you start to see you 100, 150 on-line, it's probably time to address it. You don't see hardly any of them on-line right now, so I really don't believe it's necessary to start imposing costs on projects that can't bear the costs when there's not enough to even make the discussion worth considering at this point.

MR. SILVERSTEIN: I'm just trying to separate the economic argument from the causation argument because I'm not buying the argument that these projects because they're small do not make a contribution to our balancing requirement. On a per megawatt basis, the contribution is identical to a large project.

MR. WRIGHT: You're talking about basically projects that are not committed to today. They're --

MR. WOODIN: Several of them are very close to coming on-line and others are earlier in the development process.

MR. WRIGHT: And close to being on-line, does that mean they have a signed PURPA contract today?

MR. WOODIN: No. Oregon Trails is probably, I don't know if that's why I am speaking on behalf for them, is probably the closest in the state that would be a BPA-wheeled project. There's another one out on the east side, but that's going to go into the Idaho Power line. And they haven't signed their power purchase agreement yet. They have done their interconnection studies, have reserved transmission, but they won't sign a power purchase agreement until they've got all their financial pieces put together.

MR. WRIGHT: Just current schedule, how far away is that?

MR. WOODIN: It depends. There's external issues they're still wrestling with. Mainly the financial. The world changed for all renewables, and they're still working that out. They've got equipment selected with pricing. All the other pieces are pretty much in place. They're still trying to work with their bankers.

See, this is, again, another issue with bankers. If you put costs on projects that they can't bear, then all of a sudden the banking community walks away from the project. It's not just a matter of do these projects make profit or not. It's whether they can get the financing, and that's based on operating costs.

MR. WRIGHT: I guess I'm struggling with if they place the same burden on the system as the other turbines, it's really just a matter of how many are stacked up in a string that this comes down to because they're pretty much the same size turbines, why they should be exempted. I can understand --

MR. WOODIN: If you don't want to look for reasons not to, that makes a good argument. But if you look at what FERC, WECC and the others say is these smaller projects, that they are treated differently in a number of different aspects, small generator interconnect versus large generator. When I talked to WECC about several of the transmission reservations that we have on small projects, they weren't even interested in coding them and tracking them.

So again I go back to there are precedences that say the treatment of smaller generators is different in the United States than larger ones, and one size fits all doesn't work in this case. And that's what you're trying apply is that they're all the same so let's treat them the same.

MR. WRIGHT: Can you give me some sense of where you say FERC has treated you differently? Is it for ancillary services or for what things that FERC has treated you differently?

MR. WOODIN: I think specifically for FERC, one of the ones is they came up with different generator interconnect standard based on size. WECC looks at size as to what they want to track in their system. Those are two that come to mind. If I dug deeper, I'm sure there are others out there.

MR. NORMAN: It sounds like a basic economic problem is that we're charging for a service -- well, we're pricing a service here that you're not getting paid for through the PURPA rates, so that the service is basically turning the area wind generation into a product that's firm in an hour, and you're not getting paid for that.

MR. WOODIN: That's correct.

MR. NORMAN: So that would be Brian's question. It sounds like maybe the solution to that disconnect is once we get the technology developed, the telemeter -- basically telemeter the projects into the receiving utility's balancing authority's area so we're not -- we're not providing and you're not having to pay for a service that you can't get compensated for. That would seem to align the economics here.

MR. WOODIN: If the telemetry went into the other control area, would there still be a requirement that the small project bear the cost of the integration fee, or that would be waived?

MR. SILVERSTEIN: No. That would be waived because basically the balancing responsibility would then fall on the receiving entity. It becomes -- I think that's a pseudo tie and, therefore, Bonneville would not be charging that party. And that's actually one of the mechanisms that we've talked for wind integration. Some, in fact, some of the BAs have actually requested that their wind projects be telemetered into their BA and they would take on the responsibility and then no longer pay the rate to Bonneville.

One thing that I wanted to comment on that Paul said, the technology is here today. The project that Portland General and the State of Oregon started and Bonneville has joined in is trying to do that more cost effectively, the smaller projects.

MR. WOODIN: Right. I'm part of that project.

MR. SILVERSTEIN: Technology is here today, guys. The challenge is to get the cost down.

MR. WOODIN: Well, one solution could be -- it will take some time for that. I think it's six months, but that will just get a couple demonstration projects in. It will take time for that to become a state standard. When it does, I understand what you're telling me. Is there a way that you would consider waiving the requirements until that is available and on-line? I think that we're talking somewhere in the time of -- I think the work on there should probably be finished in less than a year 's time, at least that's the goals of the group at this point.

MR. WRIGHT: I just want to restate, make sure I've got what you're suggesting. Somewhere in the range of a year until a telemetering solution can be put into effect, a waiving of the charges for that time period?

MR. WOODIN: Right.

MR. WRIGHT: Is that correct? I just wanted to make sure I had it. Thank you.

MR. WOODIN: Yes.

MR. WRIGHT: Okay.

MR. SILVERSTEIN: Thank you.

MR. WOODIN: Thank you for the opportunity.

HEARING OFFICER PETRILLO: Thank you, Mr. Woodin.

MR. WRIGHT: I would just say to our friends from the Oregon PUC, I suspect that you might want to share this conversation with your folks, as well, and I don't know if our friends from the Idaho PUC left or not, but it would be good to be shared with them, too.

HEARING OFFICER PETRILLO: Were there any follow-up comments from any of the parties on this point, on these issues?

Mr. Mundorf, did you have something you wanted to say?

MR. MUNDORF: Very briefly. If I'm getting the logic correct on this, it's a waiver of the charge, the costs will still be there, so we have to find someone's pocket to dig the money out of, and I'm assuming that would be transmission, not the power customers. But I just leave that at your plate to sort of observe, because if we could waive the cost, that would be terrific, but so far we've failed to find a way to do that. That would be opinion one.

Point two would be my acquaintance with PURPA is modest, but it's a choice that the resource sponsor makes with regard to how they're going to market the resource. So I guess I'm having a slight problem. When a resource sponsor chooses to take the PURPA route as opposed to going to the market and being able to retrieve the cost, why it is that that choice on the part of the resource sponsor results in a cost -- strike that -- a charge waiver for that particular resource? It strikes me as odd that you could make a choice, I mean, limit the amount of money I'm going to get and, therefore, someone else ought to pay the cost that's imposed on the system. That would be point two.

Point three, I was interested in Brian's discussion of telemetering out. I think that just sends the power essentially into some other BA. Does that -- that doesn't make the cost go away. I think all it does is shift the cost out of Bonneville's BA and makes it a cost in the BA that receives the power, because they'll still have to balance it. So what it does is cause the resource sponsor to stop begging at our door for a waiver and go down the road to the next BA and beg for them for a waiver because the cost is going to be a net gain rather than this one.

Is that a correct understanding, Brian?

MR. SILVERSTEIN: Yes. That does shift the cost to the recipient BA, presumably the purchaser.

MR. MUNDORF: Costs are sort of like energy. They never go away; they just move around a lot. I wouldn't look -- I could look at the installation of telemetering as a solution to our problem, but it just sends it down the road to somebody else.

HEARING OFFICER PETRILLO: Anything else?

MR. MUNDORF: Thank you.

HEARING OFFICER PETRILLO: One other comment over there?

MS. DENNISON-LEONARD: Sara Dennison-Leonard for Seattle City Light.

I had one observation which is based on my familiarity with WECC standards and FERC standards. Typically those exemptions for smaller generators have to do with an assessments that they have minimal impact on the bulk electric system from a liability standpoint, so it really is kind of an assessment these things aren't having an analogous impact to the big central generating stations. So I'm not sure if it's really a relevant comparison to say there are thresholds in the WECC standards and the NERC standards that treat small generators differently because it's, in fact, due to their different impact on the reliability of the bulk electric system.

MS. SEYMOUR: This is Melissa Seymour, Iberdrola.

I just wanted to make a point of clarification that large wind generators can't necessarily pass through the cost of the wind integration rate in existing contracts as was proposed here, and it's just a point that we need to make for the record. In some instances, there's no way for a generator to pass those costs on. It's a cost that they're seeing in the economics of the project they develop.

HEARING OFFICER PETRILLO: One more comment.

MR. DRAGOON: Ken Dragoon, Northwest Wind Group.

The assumption that the costs are similar for small wind projects, I think that that's at least an issue in an open docket in the Montana Public Service

Commission and there's quite a bit of testimony in that docket, I believe, that suggests that the costs for integrating smaller units are much less than pro rata. So I just think that's an important consideration.

I think it's a major issue of whether there is, in fact, the same kind of effect on the bulk power system reliability or not, and I hope we don't just assume that it's the same impact and move on because I don't think that's the case.

HEARING OFFICER PETRILLO: Mr. Murphy.

MR. MURPHY: I think we would much prefer a solution that would work for everybody, and that is to get the cost down which is what I suggested this morning is implement the DSO 216 and hold everybody to it and have a lower rate.

HEARING OFFICER PETRILLO: Is there another comment?

MR. HELLMAN: Just one. Marc Hellman, Oregon PUC. And we will forward these comments or conversations on it.

I did want to point out that to non-firm versus firm, firm has to deal with capacity payments on a long-term planning basis, so I would view wind integration, if you know what your power availability is for the next hour, is a different issue than planning how much capacity do I need five years from now. You said, okay, what's it going to be? Well, it's going to be firm, but it's anywhere from zero to ten. That doesn't quite help on that issue.

HEARING OFFICER PETRILLO: Anymore comments? Hearing none, we're adjourned. Thank you very much.

(Hearing adjourned at 6:05 p.m.)

CERTIFICATE

STATE OF OREGON)
) ss.
County of Multnomah)

we, Teresa L. Rider and Karen Smith, Notaries Public for Oregon, certify that the hearing here occurred at the time and place set forth in the caption hereof; that at said time and place we reported in Stenotype all testimony adduced and other oral proceedings had in the foregoing matter; that thereafter our notes were reduced to typewriting under our direction; and the foregoing transcript, pages 3 to 308 both inclusive, contains a full, true and correct record of all such testimony adduced and oral proceedings had and of the whole thereof.

We further advise you that as a matter of firm policy, the Stenographic notes of this transcript will be destroyed two years from the date appearing on this Certificate unless notice is received otherwise from any party or counsel hereto on or before said date.

Witness our hands and notarial seals at Portland, Oregon, this 11th day of June 2009.

Teresa L. Rider, RPR, CSR
CSR No. 29906

Karen Smith, RPR, CSR
CSR No.