BEFORE THE WASHINGTON STATE

UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, vs. AVISTA CORPORATION d/b/a AVISTA UTILITIES, Respondent.	Dockets UE-110876 and UG-110877 (Consolidated) Pages 129-219

SETTLEMENT HEARING, VOLUME V

Pages 129-219

ADMINISTRATIVE LAW JUDGE DENNIS MOSS

2:30 P.M.

NOVEMBER 8, 2011

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SPOKANE, WASHINGTON; NOVEMBER 8, 2011

2:30 P.M.

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P R O C E E D I N G S

JUDGE MOSS: Yes, there is one correction to the testimony that Mr. Meyer informed us of. We postponed that testimony so everybody could make the correction. If you will direct us to the page.

MR. MEYER: Yes. Page 16, please. Imagine that, a lawyer taking away words rather than adding words. It's at line 17.

JUDGE MOSS: Ah, yes.

MR. MEYER: We'll strike the word "take" and leave the word "advocate".

JUDGE MOSS: Well, could have left it a shorter word.

MR. MEYER: Could do it that way, too. I didn't mean to say it.

JUDGE MOSS: Just a little levity.

MR. MEYER: And that really was the only edit that I'm aware of.

JUDGE MOSS: Thank you very much.

MR. MEYER: And just to clarify, because we have already admitted all of the exhibits, including the joint testimony, I don't foresee any need to qualify the witnesses with some examination.

JUDGE MOSS: That's not necessary.

MR. MEYER: Thank you.

JUDGE MOSS: And following up on that comment, we did have a session earlier this morning in which we took care of preliminary matters, such as the entries of the exhibits into the record and taking the appearances of counsel. We won't repeat that.

We do have our witnesses now. I'll just note for the record that Mr. Ebert by prior arrangement was excused from attending today as a witness, but is available to us by telephone if we need him for some purpose.

Otherwise, we have we have our four witnesses here, Mr. Schooley for the staff, Ms. Daeschel for the Public Counsel, Mr. Schoenbeck for ICNU and Northwest Energy Coalition, and Mr. Norwood for the county.

Okay. We think these speakers are voice activated, but we're not certain. We'll let you know. All right. I'll ask that the witnesses who are present please rise, raise your right hands.

Do each of you solemnly swear or affirm under penalty of perjury that the testimony you give in this proceeding will be the truth, the whole truth and nothing but the truth?

THE WITNESSES: I do.

JUDGE MOSS: Please be seated. Thank you. All right. I had alerted witnesses and counsel off the record beforehand that the commissioners have expressed an interest in hearing from probably each of you would be appropriate, since your perspectives on the question may be slightly different or somewhat different, a statement, a brief statement as to your view of the settlement in terms of why it is -- why it is in the public interest.

And I'm indifferent as to whether you start at one end or go across or one of you wants to go first, that's fine with me.

MR. NORWOOD: I'll go ahead and start.

JUDGE MOSS: Norwood?

MR. NORWOOD: Yes. Just briefly I wanted to start out by thanking the parties for the constructive work that went on through the settlement process. I should note that the parties started early on discovery, and we appreciate that.

There were a lot of data requests, lots of information changing hands. We -- we -- the settlement agreement recognizes a need for additional revenues, and even though the parties didn't agree on all the pieces to the revenue requirement, there was agreement in the end on a level of rate increase that we all agree was reasonable and appropriate and in the public interest.

As we worked through the discovery and settlement discussions, there were concessions that we made as a company, but we also recognize there was concessions made by other parties, and in the end we believe it is a settlement that is -- that balances the interests of both the company and our customers.

JUDGE MOSS: Thank you.

MR. SCHOOLEY: Tom Schooley for commission staff. Staff did conduct a thorough audit of the company and reviewed all the data requests from the parties in determining what options we had to take as staff, and we did review a range of options to determine how we would approach this case.

When we got to the settlement conferences, we -- coming up with this settlement, we agreed that the magnitude was less, that the removal of the EELA was in the public interest, that vegetation management costs would be maintained at the actual levels, and the company's still going to be spending that amount.

Update was -- for the power cost was to the most recent levels. The rate design does move towards parity. And there was no issues in the service quality.

Overall among the range of options, the main one is: Does the company receive enough money to meet their needs for the near future. And since the company agreed to it, we agree that that's all right, that seems to us that settlement is in the public interest.

JUDGE MOSS: Thank you, Mr. Schooley. And just for the clarity of the record, you referred by acronym to the EELA, which I will just state is the electric energy efficiency adjustment mechanism that the company proposed at the outset of the case.

MR. NORWOOD: That's correct.

JUDGE MOSS: Mr. Schoenbeck, are you okay to go next?

MR. SCHOENBECK: Thank you. I'm here today to testify on behalf of the industrial customers that kind of procure both gas transportation services from Avista as well as electrical service.

An important part of the black box revenue requirement in both cases is there is a substantial reduction from what the company first requested with respect to the electric revenue requirement. The reduction from 38 million down to 20 million was a substantial haircut, if you will.

In large part we felt that recognized several significant power supply adjustments we would have been advocating in the case, so we certainly thought a 20 million dollar revenue requirement level was quite equitable on behalf of both the company and the industrial customers.

With respect to the gas revenue requirement, again it was a substantial reduction down to 3.75 million dollars. And we felt it was appropriate, given the black box nature, but there were significant reductions in our -- in our belief with respect to the return on equity and capitalization structure.

Another aspect of the gas settlement was the fact that the gas decoupling mechanism that's currently in place is staying as is, and was significant for us as well as the recognition of the additional objection per capacity in the revenue requirement.

So from the -- so those are our chief things we'd like to point to on why the revenue requirement's in the public interest.

With respect to rate spread and rate design in both cases, the revenue requirement or the rate spread is being allocated in such a way it's moving towards cost base rates. And the rate design from the industrial perspective, so for the transportation rate schedules in schedule 25, they are also moving in a cost base manner that we appreciate and, again, is in the public interest.

Finally, one thing that hasn't been mentioned, part of the settlement is a stay-out period, so we considered the tradeoff of having the price certainty of the rates going in effect on January 1st with the tradeoff of Avista cannot convene for a new general rate increase until April 1st of 2012 being a significant thing as well.

So taken together, we think the settlement on both the electric revenue requirement and the gas revenue requirement is in the public interest. Thank you.

JUDGE MOSS: Thank you. Ms. Daeschel.

MS. DAESCHEL: Thank you, your Honor. This is Lea Daeschel on behalf of Public Counsel, for the record. I'd first like to state that Public Counsel recognizes that Avista's residential and small business customers are facing severe economic hardship, and that any rate increase will pose a significant challenge for them.

We are pleased, however, that the settlement substantially reduces the proposed electric and gas rate increases by nearly half of the original proposed increases.

Public Counsel endeavored to review a number of areas within Avista's file case, including and particularly the accounting audits arising from Avista's last general rate case. As part of this review, Public Counsel issued over 450 data requests in this case on various issues.

There were a number of issues of particular concern to Public Counsel, and we feel that the settlement addresses each of those.

First, Avista asked for a substantial increase to its return on investment, and the settlement includes no increase to return on investment.

Second, Public Counsel opposed the proposed energy efficiency load adjustment, and we are pleased that the settlement includes no such adjustment or any other decoupling-like adjustment.

Third, the settlement includes an adjustment for the costs related to the accounting audit, training and reporting required in Avista's last rate case. We also note that Avista will be performing further audits in the next two years, which will give the company the opportunity to continue to improve in this area, which is very important to Public Counsel.

And fourth, the overall A&G adjustment reflects a reduction in the amounts of executive compensation included in the company's file case, which we also believe is very important.

In addition, the settlement includes a spread of both electric and gas rate increases to assign less cost responsibility to residential customers than the company initially proposed in its filed case.

And finally, the settlement includes no increase to the fixed customer charge for either electric or gas customers, which is very important to Public Counsel.

We also hope that Avista will continue to manage its costs aggressively going forward, thereby reducing a need to continually increase rates and hopefully reduce the overall rate increases it asks for in the future.

I'm also happy to answer any questions at this time or later in the settlement.

JUDGE MOSS: Thank you very much. Now, Mr. Roseman, we did excuse your witness, Mr. Ebert, from attending, and I don't think we need to go to the trouble of calling him on this particular question.

But if you would like to make a brief statement on behalf of your client as to your perspective on the public interest, I will allow you to do so. I don't insist that you do so, however.

MR. ROSEMAN: Thank you. As we heard today, the economy and the State of Washington and the citizens in Avista's service territory are increasing need of assistance, people -- with their energy cost. As you heard earlier, many of these customers are seeking assistance for the first time ever.

There was also a reduction in the federal money coming to the state. We aren't sure what that amount will be or how great it will be, that even pushed harder on the need for rate assistance.

So we are pleased that in this case that five hundred and fifty thousand dollars will go, ever so slightly, but will go to assist more customers in Avista's territory, and we believe that's necessary and step in the right direction. Unfortunately, the need is substantial.

JUDGE MOSS: Thank you, Mr. Roseman. With that, I believe we are ready to proceed with questions from the Commissioners. Questions from the bench? Who wishes to begin? Pat? Mr. Oshie?

BY COMMISSIONER OSHIE:

Q. Yeah, I can. You know, I'll start. So get right to it, I guess. It's not that I drew any straw here that would indicate my going first. But, you know, let's talk a little bit about, you know, the -- the reasons why the parties believe that the settlement is in the public interest.

And, you know, perhaps we could -- what -- for one, Mr. Schoenbeck, you just testified that the settlement recognized ICNU's power cost adjustments or at least some portion of them.

Well, since there was no testimony on file, we have to rely on the witnesses at this point to tell us what is it that ICNU was taking issue with with the company? What are the power costs adjustments that ICNU was prepared to make? And what was the value? And what do you -- how do you believe that that is reflected in the settlement?

BY MR. SCHOENBECK:

A. That's a obviously a very good question. I have to be careful, because you might get a different answer from Mr. Norwood, because there are tradeoffs.

Q. And I understand that. And each party made a decision to accept the settlement or not oppose it or whatever position that they're taking here for their own reasons.

It's not that you all have to be joined at the hip as to why you entered into it. Really the question is -- I'm going to be digging in a little bit with each of the witnesses on what was going on, what drives your thinking as to -- in some detail as to what, you know, what got you to the table when you settled on this number.

A. Well, focusing on power supply, in collaboration with staff, we had identified somewhere in the range of 11 to 12 power supply adjustments. It included several purchased power units, some interutility, another one that -- a qualifying facility or a (inaudible) facility.

There was an issue with respect to REC revenues. There was an issue with respect to market prices, short-term sales transactions, both on the electric side and the gas side, as well as what the current market price of power is.

In addition to that, there was also a traditional issue we've raised several times, and it has to do with the whoops three agreement and how that cost is reflected in rates.

So having a total amount associated with all these adjustments, you also have to consider what is your likelihood of success before the decision makers sitting in front of us. And you look at each adjustment and generally give it some sort of a weighting or probability based on what's occurred in the past.

At the end of the day we say, yes, this 20 million dollar revenue settlement we have before us may not be fully reflecting all of our adjustments, but it's pretty much reflecting an expected value, and what are we getting for recognizing a value, an expected value that I think we might get if we went to the full litigation.

And that gets into the tradeoff I mentioned about the price certainty, particularly for industrial customers where their electrical costs is not an insignificant amount of their annual budget when they're preparing an annual budget for the next one year, two year, three years, whatever the budget cycle is.

Generally in the fall of the year, there's a certain benefit to having the price certainty of knowing exactly what their electrical costs will be the following calendar year, in this case. So that's really the tradeoff.

That coupled with what I said in addition to that, the fact that the rates were coming in maybe a month or two earlier, but we're getting the benefit of Avista cannot turn around and file a new general rate case until April, which pretty much says their base rates won't change for the full calendar year of 2012, absent some extraordinary circumstance. That kind of probability of things.

Q. All right. And that was, of course, I think one of your the last comments you made in your initial representation to the Commission.

So you also talked about are we in cap structure, and as if that is changed, and yet there's nothing in the settlement -- there is, and the settlement does reduce the overall return, but I didn't see anything in the settlement testimony about cap structure.

A. There's an overall number. And fundamentally a utility needs an overall number to be able to approve their AFUDC.

Q. Understood.

A. So -- and of course, so when you have an overall number, that can give you at least six components. It's your debt. It's your preferred. It's your equity. And it's the cost of each of those items.

So again, if you asked me what's the rate of return in that overall number, I'm sure you'd get a much lower number than if you'd ask Mr. Norwood what's in that rate of return.

Q. I'm sure that's true. But you were just working, and I guess all the parties were, working from just the overall return number, and there's nothing in the settlement that would give us any indication as to what the parties believe to be the company's return on equity or their overall capital structure in specific terms and the short-term debt cost. I didn't see anything about short-term debt cost.

A. No, that's correct, you did not. And I think part of what was going on in two very long days of trying to settle this case was realizing, going item by item by item by item down the whole list of issues that were on the table, we weren't going to get anything done.

And that's why we reversed field, so to speak, and said, well, maybe can we agree to an overall number instead of a whole host of how we treat 30, 40 some odd adjustments.

Q. Now, I think one of the other comments and that you made had to do with the Jackson Prairie revenues. And your understanding of the effect of the settlement is, you know, how is that going to change?

You know, is this -- is this just a settlement for one year, and will those -- maybe you can describe -- let's start off, just for the purpose of the record, what's going to change.

There are additional revenues, as my understanding, are going to be included in the overall revenue requirement, and they're not going to be required in the PGA.

Is that understanding correct?

A. I think it's explained on page 1 of the settlement. I think there's basically two aspects of it. There's the increased revenue requirement, I think there actually is going to flow through the PGA.

And then the other aspect of it is also from a cost-to-service perspective within the cost study, what percentage of the Jackson Prairie costs should be designated as provided system balancing services as opposed to storing services.

And that in part was what my comment was addressing was the fact that recognizing the additional capacity associated with Jackson Prairie, that the system -- that percentage of the cost used for system balancing goes down. It goes down to 15 percent.

Q. So I had it just the opposite that, you know, it's going to be moved from overall revenue requirement and going to the PGA.

MR. NORWOOD: May I clarify on that?

BY COMMISSIONER OSHIE:

Q. Certainly, Mr. Norwood.

A. In the last case there was recognition that the additional amount of JP storage was going to come in to our system beginning in May of 2011, after the last rate case had concluded.

And so the agreement was to calculate a return on the inventory balance and put those dollars in the PGA. And then also the additional O&M and put those in the PGA until those dollars are reflected in base rates.

And so now that these dollars will be in base rates, if the stipulation is approved here, January 1 they'll come out of the PGA and into base rates.

Q. That's what I -- that how I read it, but I wanted to make sure I understood it that wasn't the intent of the parties that would have been -- wanted to make sure I understood what was going on here. Okay. Okay. Because I do -- I recall that now, the memory of how that was to be treated.

Okay. So maybe, you know, Mr. Schoenbeck, as long as you're there, and I want to ask a question about one of the tables here in appendix 1. I'm on page 1 of 1. I'll let you get there. You're there.

I'm looking at the -- it's under the term "authorized power supply expense." And it's a -- the complete -- the line item is, "system numbers, paren, 1, closed paren." And there you have "account 447, sale for resale."

Now, can you explain what that -- you know, what we're -- what's being reflected there? When I think of sale for resale, I'm thinking of revenues that are being generated through the sale of electricity to county departments.

And -- but the way that this -- maybe I don't -- this is included as an expense item. And I'm looking for -- I didn't see a counter item on the revenue side. So I mean, is it -- what's going on with that?

BY MR. SCHOENBECK:

A. It actually is a credit. It is being a credit.

Q. So should there be parens around all those numbers?

A. There could be. If you actually got down to the formula and in the power supply expense, if you're in the Excel spreadsheet, like unfortunately some of us have to be, you'll see there's actually that line, the 447 line, is actually subtracted while the others are summed.

Q. Okay.

A. And that is reflected, both the modest amount of short-term berm sales they've made, plus the market sales that are through the overall modeling. So that assumes a credit, because all those costs are in the fuel and the purchase power lines as well. We include all the revenues to the end.

Q. Now, I didn't see anything here as far as -- as an expense item as the cost that the company incurs in hedging its natural gas requirement for the electric side or the gas side.

So let's start -- just let's stick with the electric. Where's that found? And Mr. Norwood's up there. If we wanted to look deeper, where would we find that expense?

BY MR. NORWOOD:

A. On the same page down below you'll see broker fees.

Q. Uh-huh.

A. We generally do not enter into options; in other words, buy an option. We typically will do fixed-price transactions, and so you don't pay dollars up-front. All you're paying is a broker to do the transaction for you, link up with another party. And so you can see the total amount for the year on a system basis is about $366,000.

Q. And what does that reflect, Mr. Norwood?

A. That reflects the fees that we pay to a broker to help us find parties for the transactions that we need to do, whether it's making a sale or purchase.

Q. Is that -- is that the full extent of how you made, either financially or physically hedge your gas requirements for the year?

A. No. We also have contacts with a number of utilities and marketers in the Northwest who will go directly to those parties also in addition to going through brokers.

Q. So let's talk about financial hedges. Does the company enter into financial hedges for its electric, you know, power supply for its natural gas generators?

A. Yes, we do.

Q. And what's -- what is the cost of doing that?

A. There isn't an up-front cost. What we would typically do is contract with a party to fix the price for us. For example, if in the third quarter of next year we want to buy gas for one of our combustion turbines, and the market price is, for example, $4 a decatherm right now, we may contract with a party to fix the price at $4.

And when the -- we come to that period, if the price is actually 4.50, then we get the gas at $4. And they would have to -- if they haven't hedged it themselves, they would buy the gas for 4.50 and deliver it to us.

Q. And what's the cost to the utility for -- I mean, I know it can vary from transaction to transaction and the quality of your counterparty and lots of different factors, but what -- you know, you just used a hypothetical, so maybe give us a hypothetical cost. And you can pick a hypothetical amount of gas so that gives us some meaning.

A. Right. It isn't based on volume. It's based on a transaction fee with the broker. And it's -- I'm trying to think of how much it is. But it's just a fee for the broker linking us up, if we didn't do it directly with the counterparty.

So it's literally in the hundreds of dollars for a major transaction to buy the gas. So in other words, we're not buying an option and paying a premium up-front for this. This is simply fixing the price for a portion of the gas, and so there is no premium you pay up-front or when you get there.

Q. It seems, if I remember from your last case, we asked the company for -- to, I think, rerun its power costs including updates on natural gas, which would include an update on cost.

And one of the -- and if I recall correctly, the testimony that we received in response was in part, "We hedge -- have hedged 90 percent of our fuel supply requirement."

And so the question that I think it asks is, well, if the company's hedging to that extent, then what's the purpose of a PGA or the bands in the ERM as -- not the PGA. Excuse me. Strike that.

But the ERM, you know, if -- because the ERM is there, I mean, that's a risk-control mechanism, and so are hedges. I mean, is this like a belt and suspenders thing where you're within the bands of the ERM, but the rate payers are also paying?

And if it's reflected as this amount, you know, it's a lot of money, but maybe not in terms of the overall cost of fuel for the utility. But, you know, if it seems like one somewhat substitutes for the other.

One is that, you know, it reflects what the company can control, and it can control its costs year over year based on the hedges. And the PGA, if you're coming into rate cases -- or excuse me. Strike PGA. ERM. Going to do that all day.

It would -- you know, so what's -- what's the relationship there? And do another parties have any questions about whether, you know, given the extent of hedging that it's, you know, an ERM, at least the bands, the way they're structured now, maybe should be readjusted going forward?

I mean, this is -- you know, it's all about risk management. And so let me ask Mr. Schoenbeck, at least to start off. I'll ask Mr. Schooley, Ms. Daeschel, and then the company can respond.

BY MR. SCHOENBECK:

A. Certainly. We actually do look at the company's individual hedges in every rate proceeding. In this particular proceeding, there -- in all those proceedings ultimately there ends up being a mark-to-market adjustment.

So it goes beyond the broker fees that you were talking with Mr. Norwood about, which I agree with his answer that the administrative costs of entering into a hedge is minuscule.

It's -- you can do it electronically, and you miss platforms, and it's lost in routing of the calculus. But with respect to the ultimate mark-to-market adjustment, those generally do run into the millions of dollars in total.

And it is reducing your risk to a certain extent, because you locked in a given price for a given volume. So with respect to that, yes, it has reduced their risk, and it's reduced the risk that -- or the volatility exposures that ultimately end users can see.

But there are additional risk that are being addressed through that ERM mechanism. For example, the hydro risk. You can't lock in what the hydro is going to be.

Also going back to just the amount of hedges you enter into, they are -- it is for a specific volume, so you truly don't know what your gas need is going to be that far in advance.

That's why I personally feel it's bad to hedge a hundred percent in advance of your need, because you don't truly know what your need is until you get close to the period and you'll actually be burning the gas.

But given the less volatility in forward prices, most utilities, including Avista, have not procured as many hedges, basis swaps, as they have in the past. I can't recall the exact number, but they're somewhere -- it's either 4 or 14 million dollars of mark-to-market adjustment in the company's revenue requirement.

And it's probably -- on the gas side, it's probably reflected under the fuel cost in this first page of the first exhibit or appendix you pointed to.

Q. So is it then based -- I'm left with an impression based on your testimony that the utility perhaps is not hedging its -- the gas costs to the extent that it had and that we saw in the last rate case.

A. I believe that's correct. It certainly is with respect to what the market-to-market adjustment is. And I think as a general rule from what I've seen looking at several different utilities, there's almost -- they're almost getting too comfortable with the long-term forecasts that are saying the price of gas is going to be $4 or $15 dollars the next year.

So I don't think the volatility in the forward market aren't as broad as they used to be, so I don't need to hedge as much. And that gives me some discomfort as well, but that generally seems to be the attitude.

So generally most utilities have not bought the hedges in the last 12 to 18 months that they have in the past.

Q. And I would assume, too, Mr. Schoenbeck, that if -- as the -- as the companies rely more upon natural gas as a fuel of choice for generation, that the -- that would have to get reflected somehow in the ERM.

In other words, the hydro risk would diminish as the use of hydro power begins to decrease by the utility because of load changes.

A. It becomes a smaller percentage.

Q. That's right; okay. And given the detail in that answer, Mr. Schooley, Ms. Daeschel, would you like to add anything as to what your particular party is going to be concerned with, with regard to hedging and the mark-to-market adjustments and any reflection in the bans in the ERM?

BY MR. SCHOOLEY:

A. I think -- from my point of view, I think there's a -- quite a dilemma in determining what a hedge is as opposed to what the financial -- financial institutions and the accounting field wants you to think it is.

In the example Mr. Norwood gave is that they buy a certain amount of gas at a certain price at several months in the future. I consider that just a contract for a purchase.

But in the interim between those times, the accounting industry wants you to mark that to market, because in part it may not need all the gas you've contracted for, and you have to sell it at whatever the market is at that time.

So they're viewing a risk in the interim as to what the price of that gas actually will be and cause this mark-to-market fluctuations in cost over time.

But if you in the end take delivery of that gas at the price you've set, all those mark-to-markets will wipe themselves out over time, and you'll just be purchasing gas at a price that you said you would. So that mitigates or eliminates the need to have an impact on the ERM or a PGA in the between time.

Q. Yeah. The mark-to-market -- and if I understand, it's just a snapshot at any particular time and can vary day to day, and that would get reflected in some accounting way. And when it really the rubber hits the road is when something's actually done in gas, whether it's sloughed off, you know, to another party or actually used by the utility.

A. And I think that's where the ERM picks up the actuals at the time they're intended to.

Q. Mr. Norwood, so without giving the answers that you've heard -- well, Ms. Daeschel, do you have anything to add on this?

BY MS. DAESCHEL:

A. I don't have anything to add. We pretty much know, as we develop limited resources in this case, we didn't focus on power costs. I don't have any specific contributions.

Q. Okay. So Mr. Norwood, given the answers, they didn't seem too prickly to me as far as the effect on utility. So is there -- do you have a -- any other further reaction to, you know, to the questions that were being addressed?

BY MR. NORWOOD:

A. No. I think Mr. Schoenbeck did a very good job of answering your question. I want to add to that. I think what it does is it points out the amount of time and energy that Mr. Schoenbeck puts into reviewing our costs, he and Mr. Buckley on behalf of staff spend a lot of time reviewing what we do. I think that's demonstrated in his answer.

Q. So Mr. Norwood, why is -- well, let me -- this actually wasn't your testimony. Mr. Schooley, so let me ask him first.

Why is removal of the EELA in the public interest?

You use that as one of your primary reasons why. Why did that rise somehow to the top as to why this was -- why staff believes that that was such an important component of this settlement?

BY MR. SCHOOLEY:

A. We look at their load-adjustment-type proposals coming from the companies as introducing its own level of complexity that doesn't seem necessary. The measurements themselves are suspect as to how much is actually being accomplished, at least from an accountant's point of view.

And it's difficult, therefore, to quantify exactly what is -- what that number means, as to whether it's 4 million dollars or 6 million dollars or -- or is there how many kilowatt hours were saved over time.

So staff is struggling in general with those types of adjustments. And we're looking -- we don't -- so removal of those is in our interest, and I think in the public interest, because it's taking out sort of unknown and unmeasurable quantities from rate making.

Q. Ms. Daeschel, you also -- I think this was your reason number two, no EELA. So what's the -- what's Public Counsel's beef, if you will, with the EELA as proposed by the company?

Maybe asked this way: Is Public Counsel, are they opposed to the EELA for what it represents or are they opposed to the operation mechanism, because you don't think it was designed properly?

BY MS. DAESCHEL:

A. I think we would -- I think we were opposed to it for a couple of reasons. I think any type of mechanism, such as a load adjustment like this or what we might call a decoupling-like mechanism, we've certainly taken a position in the past in this type of mechanisms and have not been in favor of them and opposed them.

In this particular case, we saw the EELA as more of an opportunity for the company to essentially institute a surcharge on customers for conserving energy. So we didn't agree with how that was structured, and it also left it about a 4.3 million dollar increase to customers.

So it was a combination of the policy and how it was structured and also what it does to customer bills and the dollar amount reflected.

Q. And so this was the EELA itself, the 4.3 million dollar cost, you know, that's part of the -- the total decrease that's being advocated here; is that right? Okay.

So you also talked about -- Ms. Daeschel, you talked about an adjustment for audit findings. Now, there were issues in the last rate case that had to do with the certain costs that were -- that were included in the initial filing by the company that were for, at least it appeared based on the testimony that we heard, that they weren't costs that were related to the operation of the utility or they were -- and as a result that they should be removed.

So there was an adjustment made at that time. And there was a requirement that the company do an internal audit to, I thought in my mind, remedy, take corrective action.

I kind of thought of this as a material finding in an audit anyway, that there were -- that things were slipping through the cracks and were not properly identified in the accounting process as either falling within the utility's regulatory sphere or outside of it.

And so that took place, and maybe you can describe from Public Counsel's view what happened and why we're still seeing it here in the settlement.

A. Sure. Yes. So in reviewing the company's audit, which was an exhibit to their filing, we did see that there was an error rate or instance where they found how many -- out of all the A&G transactions they reviewed in a set sample, how many errors occurred.

And so there was a prejudice or a total number of errors identified. And so the audit essentially put forth what that percentage was, how many errors were found. And then in the company's case, they removed the costs that were identified in that audit.

And this settlement, of course, we did include a term in the settlement stipulation that went a little bit beyond just removing the costs for performing the audit and what the audit found, but we also included what we termed -- I guess what we called it an extrapolation.

So what that attempted to do, we didn't assign a particular dollar amount as a part of the overall miscellaneous adjustment in the settlement, but it did attempt to incorporate what might have been the total dollar amount if you were to take that percentage, that extrapolation of the error rate identified across the whole subset of A&G accounts.

So what we attempted to do was to recognize that this audit found a certain number of errors. But if you were to actually look at all of the transactions throughout the whole test period, there would probably be more, because we understood that that was a likely scenario.

So the settlement does attempt to recognize that. And in the case of finding additional inappropriate expenses in this case, as you noticed, we did review certain costs again and identify cases where they were still included, and those have been removed.

As far as why we're still seeing those, I would say that we did anticipate in the last case that this wouldn't be something that could get fixed within one year.

And we also recognize that when these changes the company decided to implement occurred, that was already part way through the test year in this case. So it was part way through 2010.

And so I think it's fair to expect that you maybe would see some errors still within this case, because there was that overlap. And I think we did realize that it would take a number of years, and so there are this -- there is this provision to continue doing these audits and hopefully continue to improve where we don't see as many instances as we did last year or this year.

Q. So what's the -- and how many years do we expect to see adjustments like this? I mean, for example -- and I'm not going to ask any more questions about this. I think my colleagues have particular questions that they want to ask about several line items here.

But I guess my -- let me just ask it this way. And the company's probably in the best position to answer this, but when is this going to get fixed? If we're seeing some recurrence here of issues that -- over a period, you know, not just question what's happened in the past, but it's going to question then what's going forward.

Some of these seem like simple accounting fixes, but obviously, you know, nothing really is maybe that simple. But, you know, when can we get some confidence that these kinds of issues have been eliminated from the initial filing so that there -- you know, can't be used as some chip in bargaining for some future -- some future particular meeting of the parties?

BY MR. NORWOOD:

A. I'd be happy to respond to that. I think, Commissioner Oshie, that we have fixed the issue, and let me give you some color around that. In the last settlement agreement, these issues were raised.

We agree to, number one, establish some additional guidelines and accounting policies, and then conduct training of our employees, which we did. And that occurred early this year, 2011.

Which means that with the 2010 test year that we have in this case, you're still going to see probably more errors than what you'll see going forward, because we hadn't conducted the training yet, nor had we established new guidelines and policies.

The other thing that we had put in place is the corporate account manager every quarter is reviewing a lot of these cost categories to make sure that employees are booking them in the right place, whether it's electric or gas, utility, non-utility.

And our group, the rates group in fact just recently in the last month did our own review of 2011 expenses to see if we were experiencing some of the same kinds of problems, and what they're finding is much fewer errors occurring in 2011.

But I will tell you that there is over a half a million transactions, expense transactions that occur a year in the company. And we will likely see some errors, but hopefully we'll see very few compared to what we've seen in the past.

Q. All right. Any comments from staff on this or -- all right. So my last area, I believe this is has to do with the -- the deferred accounting for maintenance costs (inaudible) agrees to, which is part of the settlement agreement.

So just in general terms, what's going on here? I mean, why is this in the public interest? What's changed over the last year that it creates like a material change of circumstances where we have to change rate treatment for the costs of maintenance of that Coal Strip?

Just use Coal Strip as an example. The settlement talks about volatility, but there's no description of what really is happening, you know, what are -- what is -- you know, I guess someone has to define what volatility means here, and it's a variance of what from baseline.

I mean, what kind of exposure is the company asking to be protected from here? And in particular, you know, maintenance has, you know, regular patterns and irregular patterns. In other words, some things you do annually, and some things you do every other year. And so, you know, really what's driving all of this?

I would like to hear some particulars on specific items that are either costing more or you didn't have to do before, and are not built into base rates. And the way that we do this now I would expect it was some kind of an average cost of maintenance over time that resulted in a baseline, and how are we going to adjust the baseline?

So those are, you know, a bunch of general questions. I'd like to hear some details about what's -- you know, what's driving this specifically, and what kind of exposure is the company going to be seeing. And let's start with Coal Strip and then we'll get to Coyote Springs.

BY MR. NORWOOD:

A. If I may respond. I'd like to direct you to Exhibit -- it's EMA Elizabeth Andrews 1T.

Q. I don't have it with me, Mr. Norwood.

A. Okay. Because I want to --

Q. The chairman has it. Maybe he may follow up. This might just be a softening action.

A. And it's page 52.

Q. Okay. So let's go into so what --

CHAIRMAN GOLTZ: What's the exhibit number? I'm sorry.

MR. NORWOOD: It's at Exhibit EMA 1-20. Is that the official exhibit number?

BY COMMISSIONER OSHIE:

Q. Is that the graph, the bar graph?

A. It is.

Q. So let's go -- I mean that has -- yes. I mean, that's a bar graph depiction of what you think. But what's -- what I'm asking is what's going on? What do you have to do at Coal Strip that's going to increase your cost by what factor, and why does that -- and why is that such a material change in what's going on that you need to have some special rate-making protection that is I think considerably different from what we're doing right now?

A. First of all, what we have been doing in general rate cases is not using an average, but using the test year numbers. And in the past we have proposed pro form in the cost for the upcoming rate year, the year that we're going to incur the cost during the period the rates are in effect. And there's been resistance to pro forming in a future number.

And just with regard to Coal Strip, there's two units there, and they typically do major maintenance every third year. And so two out of three years you'll have major maintenance where you may incur 3 to 4 million dollars of additional costs, Avista's share for those units.

But that's compounded by the addition of Coyote Springs 2. And in the bar chart that I referred you to, just as an example, in 2012 the expected major maintenance on that is 11.4 million dollars versus 2011 of 4.4 million. So there's a 7 million dollar change just in one year.

And that maintenance for CS 2, Coyote Springs 2, will occur about every four years. And so there's a lot more lumpiness that we're experiencing now with the addition of Coyote Springs 2 in addition to Coal Strip.

We believe this really provides a smoothing for both customers and the company. And that as we roll through, for example, 2012 or 2012 as the test year, and we don't smooth this in some way, we're going to build into rates 23 million dollars of expense when the actual cost going forward is less than that.

And so customers benefit from paying really more of an average over time, and the company experiences that, too.

BY MR. SCHOENBECK:

A. Can I throw my two cents on this one, too? I've represented cogenerators which are basically combine gas RTTs for years and years, and you do basically rebuild the plant based on either the 30,000 hours reflected or the numbers of starts that have occurred. So like Mr. Norwood said, it's basically every four years.

This is always a problem how do you reflect that, how do you reflect any major overhaul, major rebuild rates on a prospective basis.

I actually think, staying with just the test period values as adjusted is wrong. I actually do think you need to normalize the fact that the maintenance is occurring over four years, and smooth it over four years.

So you basically have to either use some sort of a four-year average for the maintenance or come up with a benchmark, and then give a deferral balance either above or below that benchmark.

So we're supportive of the maintenance deferral we came up with this in case for several years. And one of them is it's true, it's just the maintenance accounts. It does not include the operational accounts at these plants.

So it is just trying to really truly focus on the extraordinary maintenance that's going on. It's not the day-to-day operations that we're seeking the deferral.

And another important aspect from our point of view was Avista was willing to forgo any sort of carrying charge on the deferral. So in my mind it was a win-win for the -- for the customers.

And by levelizing the rates, normalizing the rates, it would be a more constant level as opposed to year-to-year fluctuations provided by the test period guidance, coupled with the fact that there's no carrying charge, and it just focused on the M accounts, not the O accounts.

Q. So why would that be true for Coal Strip? I mean, I can -- I understand your point with regard to Coyote Springs as an example, and I suppose with any other combined cycle generator that there's going to be that kind of maintenance requirement going forward.

But what about, you know, Coal Strip? It doesn't seem to me the variance really isn't there. What's in -- I guess one of the problems that I have in particular with this is I am not quite sure what's in the baseline anymore and how -- you know, how we're going to -- what the deferral's going to move from.

And it would seem as if, you know, we have to be comfortable where the baseline is, why it's set where it's at, and then move from the deferral. Unless this is -- the parties are just -- what it seems to be happening, a lawyer's going to carry it over from the last -- from the last test year, we'll carry over that number, and then we will -- you know, we're going to build this deferral in.

So is that -- is that what's going on with the baseline?

BY MR. NORWOOD:

A. Actually beginning in the very next year, you'll start to amortize away the deferral. So the baseline would be whatever your actual maintenance expense is in the test year minus what you've deferred plus what you're amortizing. So it's a pretty straightforward calculation, and you start to amortize away the balance immediately in the next year.

Q. It will be your actual. But what if your actual is, you know, twenty-three four six six, so that's your baseline then for the next year?

A. That's the starting point. But then if you're deferring anything that year, you would subtract that away, and then you would add in any amortization amount. And that would help -- in other words, if this were the year two or three in the deferral process, and your baseline was 18 million, as an example, you'd take your 23 minus the 18, so you're deferring the five.

And so your baseline now is 18 plus anything that's being amortized, which might be a million dollars. So then you have a 19 million dollar number that you use for rate making instead of 23. So that serves to smooth it out.

BY MR. SCHOENBECK:

A. And to -- and to answer the other part of the question, I think you're going -- the theory is the baseline value, the baseline value should be set at an amount that does reflect all the day-to-day reoccurring maintenance costs for the plant.

So anything above that would then be an extraordinary one-in-two-years, one-in-three-years, one-in-four-years maintenance event.

Q. And I can certainly -- you know, I can get my arms around that. And so once the baseline is set, then that's the recovery, that's in rates for the general O&M costs. But it's these extraordinary events that drive these extraordinary costs, and there's now a mechanism proposed to recover that.

A. In a levelized manner over a number of years.

Q. So let's get back to Coal Strip. If they're floating 2 to 4 million dollars a year, you know, why -- why should that be included in this mechanism? We're not seeing those big swings from, you know, 4 million to whatever that is, 12 or approximately 11.

BY MR. NORWOOD:

A. Right. The swing is less with Coal Strip. But again, you're going to have lumpiness with two years out, three hitting major maintenance, then the third year you won't.

The other thing is with Coal Strip, the units came on in the '80s. They're getting older. And so you may have more extraordinary-type maintenance that may occur from year to year.

These are some of the actually the lowest-cost resources that we have. The incremental cost is a penny. So, you know, it's -- we think it's really important to capture the lumpiness of this so as we deal with the maintenance part of it.

Q. So aren't -- aren't the maintenance costs, aren't they expensed year over year, and that's why it would get reset in a given test year?

A. They are expensed each year. Currently that's correct.

Q. So what's -- why is it a part of the settlement? I mean, I guess it makes it clear that you're not going to ask for carrying charge, what's being carried.

A. That's correct.

Q. Okay. Yeah, okay. You wouldn't earn that anyway, in other words.

A. We're not going to earn on this; that's correct.

Q. And you weren't going to earn on it if it were expensed in an ordinary manner?

A. That's correct.

Q. Okay. Mr. Schooley.

BY MR. SCHOOLEY:

A. Yes.

Q. Why is this in the public interest?

A. I think that smoothing of the expenses makes it, from test year to test year, less volatile in rates. So if you happen to get a high year and build that into rates, it helps the company in a sense. The next year it's lower so they can turn more profits as reported on the bottom line.

But overall I think that standardizing this cost will perhaps make it easier from year to year to take out some of the volatility in rates, but lead to higher rates (inaudible).

Q. Well, and I understand that. But let me -- and I'll just, you know, be the devil's advocate here. Company's coming in year over year. So, you know, I'm -- if they're going to stay out -- in other words, you don't want 23 million dollars' worth of O&M costs built in in a rate year and finally stay out for three years when they're actually paying 8 or 9.

But they're coming in year over year. And I guess this does smooth some, but if the baseline gets reset at the highest number, how does that help rate payers?

A. I think if we -- this would be one step down the road of perhaps trying to mitigate the need for coming in for year after year if they have mechanisms like this. And I personally don't want to see this expanded for every type of cost.

But I think once we start looking at rates in a holistic manner, and staff is trying to look at ways to mitigate the need for rate cases every year, and this type of program even expanded on a broader sense may result in perhaps fewer rate cases.

Q. Well, I think the public would really appreciate that, there's no doubt. So how is this -- does this set a precedent, Mr. Schooley, for -- for PacifiCorp or Puget to ask for the same kind of treatment? Don't they both own Coal Strip?

A. They do, and Puget is asking for this in many different ways. They already have -- one commenter today was complaining about six lines on their bill when Puget has maybe a dozen lines on their bill. The telephone bills are even worse.

So I think it is not necessarily precedent-setting, but it is a step in the direction that many of the companies are looking down in terms of trying to smooth their expenses in order to mitigate the need for them to be requesting rates every year as well.

I don't want to go down a line-item-by-line-item type of accounting for every variation in expenses, but we need to be broadening this concept in order to come up with fewer rate cases and sufficient returns to the utilities.

Q. So staff looks at this as potentially a driver of either the company's -- I would think it would be an incentive to stay out, if you've got 24 million dollars in base rates and you're really incurring about 11 in actual costs. But I guess it can work both ways.

A. Depends on how it's -- how much it is relative to your total revenues.

Q. Well, that's another question. I mean, what is this in terms of total revenues? You know, given the outside magnitude, what are we talking about here? What kind of risk are we sloughing off, you know, or at least what are we recognizing here?

BY MR. NORWOOD:

A. Total revenues on a system basis, electric and gas are approximately a billion dollars. But in terms of costs and benefits, I really see this as a benefit to both the company and the customer in terms of smoothing out the cost to them.

Q. So again, a billion dollars in total revenues, and this is -- maybe reflects 5 million for between 2011 and 2012, round numbers?

A. Yes. But I think it's also important to keep in mind that if we are in a situation where if we were to use a historical test period number that's lower than what we're actually going to experience, then the effect on the company would be the impact on the earnings of the company, which is going to be a small piece of that billion dollars.

So the impact would go straight to impact earnings. And earnings are in the neighborhood of 80 million dollars, 80 to 90. And so that 5 million dollar impact would go directly to impact the earnings if we're not -- if we don't have some way to deal with that volatility.

Q. Well, you know, how does the company deal with it now? I mean, don't you -- you have things that you have to do, you have things you want to do, and that's, you know, throughout the whole company. It's not just focused on Coal Strip or Coyote Springs.

You know, don't you delay doing certain things so that you would have enough money to do what you need to do in a new area or is it just it's on schedule and you have to do this by a certain day, so we just do it?

A. We have done some of that in terms of delaying, but there's only so much of that you can do. So this is a way to address this cost volatility and allow us to continue to do what we need to do.

Q. All I'm saying is that it's -- I understand, you know, if you have to expense, it's going to effect revenues or total earnings.

But there are -- there -- if you are -- there are ways to avoid having to spend money and to take -- and I think you've heard it this afternoon in the Spokane Valley of people saying that they've had to do budget adjustments that would allow them to accomplish what they wanted to do without -- in their view, the fixed income rate payer's circumstance, they have only a certain amount of money to work with, and they have to make it stretch.

So all right. I don't think I have any other questions. I don't know who goes next.

JUDGE MOSS: All right. Well, I think this would be a good moment to take a brief recess. I emphasize brief. Let's just take five minutes, and then we'll be back on the record.

(A break was taken from 3:34 p.m. to 3:41 p.m.)

JUDGE MOSS: All right. We have our witness panel again, so why don't we continue. I believe Commissioner Jones has some questions.

BY COMMISSIONER JONES:

Q. Good afternoon.

BY MR. NORWOOD:

A. Good afternoon.

Q. I'm going to follow up on some of Commissioner Oshie's questions on accounting, this deferred accounting. And I'm also going to ask some questions on vegetation management, and a little bit on the net power costs.

So why don't we start with net power costs, Mr. Schoenbeck. If we could turn to page that appendix 1 in the settlement stipulation, that's page 1 of 1. I just want to clarify a couple of points.

So you can assure me -- I think Commissioner Oshie raised this question about account 447, sale for resale. It appears it has a mix of revenues and expenses, taking a look at the total column. But is that correct?

BY MR. SCHOENBECK:

A. Yes, it is. The -- the expenses are in fact the first three lines.

Q. Okay.

A. Which add up to somewhere in the region of about 250 million dollars.

Q. Right.

A. And then if you subtract off actually the next two lines, which are the sale for resale amount and our agreed-to black box power supply reduction amount from the company's filed case, that gets you to the net of 191.8 million dollars.

Q. Okay. So you can assure us that the numbers add up?

A. I hope so.

Q. I've never seen this term used before, Mr. Schoenbeck, in a settlement agreement or in a case, "black box power supply reduction." Is this common? I mean, we often see black boxes in cost of cattle, but --

A. Right.

Q. You practice many cases. Is this common to use this type of terminology?

A. As far as I know, this might be the first time we've used it in an Avista case where there's -- again, there's a whole host of adjustments that are being disputed. We came up with a handful that created this precise number. That's why we labeled it a black box.

Q. And as you said, you came up with roughly net power cost adjustments that you wanted to?

A. Yes.

Q. Okay. A couple questions about mark-to-market adjustments. Were you part of a case with Puget a couple years ago where mark-to-market adjustments was a litigated matter?

A. Yes, I was.

Q. And which position did you take in that case?

A. I took the position which I've always taken, and that's a utility should not hedge beyond their need for gas. So if a utility believes it needs to ERM 50,000 hydrotherms per day in its gas facilities, it's not prudent for them to incur costs associated with a value greater than 50 million decatherms. So what -- the dispute in the Puget case went forward to the volume being procured.

Q. So it was not so much the characteristic or the principle of mark-to-market adjustments, it was more the volume. You felt the volumes were --

A. The volumes were in excess of need was my case.

Q. I see. Because I think in that case, didn't we decide to go basically with the company's position?

A. Yes, I lost that one.

Q. Yes.

A. Thanks for reminding me.

Q. So just so I understand how this mark-to-market adjustments work in this case, so what's your -- I think you said the number 44 million.

So is it correct to assume that the mark-to-market adjustments aren't included in this case?

A. Yes, it is. Actually, since I responded to Mr. Oshie's question, I found my work paper. What's reflected in this case is approximately, the Washington basis is 12 million dollars in mark-to-market adjustments.

Q. And how does that appear in the case? Is that a balance sheet item or is that an income statement item or how does that appear in terms of --

A. It would appear within appendix 1 we were just looking at.

Q. Okay.

A. It would appear as a purchase power cost.

Q. What line is that or what account number is that?

A. It would be in two lines. I believe it would be under the purchase power account, 555.

Q. That's account 555?

A. With respect to the electrical amount. And then with respect to the gas hedges, it would be under 547.

Q. Okay. Okay. Thank you. I think those are good clarifications. Let's turn to vegetation management. I want to ask these of Mr. Norwood.

What was your proposal in the direct file case file on vegetation management?

BY MR. NORWOOD:

A. We had proposed to increase the test period number from, I believe, 3.9 million up to 6.9 million.

Q. And what was the justification? I haven't had a chance to read it directly. What was the justification for that? Was it actual -- well, it wouldn't be actual work. You're projecting into the rate year; correct? The level of vegetation management activities. So what -- what was the basis for that, for requesting such an increase?

A. Our energy delivery people had conducted some studies to see, in their view, what the optimum tree trimming cycle would be, whether -- in the past we've had cycles as long as six-plus years.

I think right now we're in the neighborhood of a five-and-a-half-year cycle. And their recommendation was to go to a four-year cycle, meaning you'd go through your distribution transmission systems and you would take your distributions on a four-year cycle.

And as we worked through settlement discussions, the agreement was to -- to not include that level of funding in the settlement agreement, but something less.

Q. My thrust of the questions are a concern about NERC requirements over reliability issues, if you do not spend up to the amount you should be spending on vegetation management. So I'm actually coming at it from that direction.

But have you had any issues with NERC, penalties or lack of compliance with NERC requirements concerning vegetation management?

A. I'm not certain of the answer to that question, but my understanding is we do not have a problem there. I think we have -- my understanding is we've been pretty -- we have covered the transmission area carefully to make sure that we're complying with all NERC requirements. That's my understanding.

Q. And by transmission, you mean everything above 110 floor volts or what do you mean by transmission?

A. Transmission I think is 115 and above, is my understanding. So -- and my understanding is the NERC requirement applies to transmission.

Q. Okay.

A. And so this issue of veg management addresses both the transmission piece as well as distribution. And so my understanding is we will continue to do everything we need to do on the transmission side to comply with everything that NERC lays out.

On the distribution side, as we look at dollars that we've agreed to here. And in fact yesterday and today I checked with our folks to see what the plan is for 2012, and our plan actually is to spend more than what we've laid out here to ensure that we're doing the right thing going forward on veg management spending.

Q. How much more?

A. My understanding is the budget is 4.7 million for 2012 versus the 3.9 here.

Q. Okay. Well, that was my concern is that you are conducting these veg management activities in a way that ensures the reliability both of the distribution side and the transmission side supervised by NERC, and that you are -- that we aren't in effect shortchanging you on this one.

So I guess you can assure me that this 3. -- what was it? 3.908 million, Mr. Schooley, the -- this is for you. What's the -- I'm a little confused. The minimum annual spending, what is it? Is it 4.025 or 3.908?

BY MR. SCHOOLEY:

A. It was 4.025 was the last rate case. The actual for the year was 3.908, and that is the number that is stipulated to be the amount that they will be spending, at least that much, in the future and in this case.

Q. Okay. Okay. But Mr. Norwood, what you were saying was that your engineering staff, whether it's on a four-year cycle or four-and-a-half-year cycle, still wants to spend a little bit more than that 3.9 million, and you intend to perhaps up to 4.7 million?

BY MR. NORWOOD:

A. Yes, that's the current plan.

Q. Okay. Okay. Final line of questioning is on the O&M track that Commissioner Oshie -- we had a good discussion of that, but I still had a couple of questions.

Mr. Norwood, you would read, in the Idaho jurisdiction, to a different type of mechanism, as I understand it, as our staff was analyzing for us at least.

Could you describe the differences between the Idaho improved mechanism and the one in this settlement agreement?

A. Just two differences. One is in Idaho the O, the operation expense is also picked up, any differences in that, so it's O and M.

And secondly, the amortization is over a

three-year period instead of a four-year period, still no carrying charge. So those are the only two differences.
Q. Now, how would you distinguish between an operating expense and a maintenance expense?
A. I've forgotten some of my accounting, but my understanding is the FERC has descriptions of the types of costs that go into the operation accounts, and so that's pretty straightforward. And those that do that work understand they need to charge the O to the O accounts and the M to the M accounts, as I do explain that.
Q. Is this what is described on page 8 of the settlement stipulation, they are -- it -- it has in a parentheses on about line 6, FERC accounts 510 to 514.
Is that what you're referring to, Mr. Norwood?
A. Those are the specific maintenance accounts that we would be picking up.
Q. So that doesn't answer the question of what I asked earlier of what is the difference between operations and maintenance in FERC accounting.
I mean, is it -- is it -- I guess what I'm driving at, is it absolutely clear what goes into these buckets, what goes into these FERC accounts and what does not?
A. Actually, yes. In fact it was the accountants that worked through the specific accounts that are in and out of this, and so there was agreement on these particular

accounts.

The other thing, you'll notice the account, the organization codes. As we work through this, we actually dug deeper, and the agreement was the costs charged to these maintenance accounts would be for only third-party contractor maintenance.

And the company -- to the extent we use company labor to do this maintenance, it would not be charged to these accounts, so we would not be tracking that.

And that's another distinguishing factor with Coal Strip and CS 2 is that those plants, we primarily contract with third parties to do that. We have to contract ahead of time to have them available to do it, because these are major generating plants versus the other plants.

Q. And that's in footnote 7?

A. Yes.

Q. Now, I think it was Mr. Schoenbeck who supports this mechanism. He said there were two ways of getting at this issue of volatility, extraordinary expenses, which I agree is a legitimate issue.

You said there are two ways of getting at that. One would be a tracker like this that creates a regulatory assent according to accounting rules, as what used to be called FASB 71.

And then the other would be to go to normalize it over a three-, four-, five-year period and try to average it out.

BY MR. SCHOENBECK:

A. That's correct, look at the historical expenditures on those accounts for the last three or four years and take an average.

Q. So I guess my question to Mr. Schooley is I've heard you speak before of general skepticism about creating too many regulatory assets, trackers, because it's a burden on staff, they're difficult to track -- excuse me -- they're difficult -- strike that.

They're difficult to monitor every year, true up. But in this case you're supporting an additional tracker. So between those two options, I mean, what swayed you one way or another between those two ways to kind of normalize the expense?

BY MR. SCHOOLEY:

A. One -- well, one point to make is this isn't a tracker in the sense that there's not a rate that will be recovering this specifically identified for this cost. It's just a deferral to be recovered through general rates as the expenses vary.

Q. And that's true. And it's important to note this is an expense, not a capital --

A. Correct.

Q. -- expenditure, which is usually done I think through a FASB 71 type tracker; correct?

A. 71 applies to expenses, for the most part.

Q. Does it? Okay.

A. I think the company persuaded us that this was a fair way to handle the volatility in these accounts. As Mr. Norwood just said, this is primarily third-party expenses, like companies like General Electric go out and say, "We'll maintain your plants for 40 million dollars for the next 4 years," and they go off and do that.

So it's -- it's a fairly known amount. There are some variations in there for parts and such, but that's sort of one trend that's going on in the industry that seems to be appearing in all the companies.

The other is the differences from one year to the next are substantial, but they're not highly variable, not like from 3 million to a hundred and fifty million, that type of thing. So it seemed like a fair way to go about handling this expense for this company.

Q. Mr. Norwood, you've filed accounting petitions with the Commission before, have you not?

BY MR. NORWOOD:

A. Yes, we have.

Q. Quite a bit, haven't you?

A. I guess that's a relative term.

Q. Okay. That is a relative term. So why didn't you do it in this case? I mean, isn't one option for the company to file for an accounting petition per FASB 71, create a regulatory asset, and then we would vote on it in an open meeting?

A. We've done some of that. Some of the comments that we get from some of the parties is, you know, why don't you do it in a general rate case where we can look at everything at the time. And so -- and that's part of why we chose to propose this in the rate case so that it could get a thorough review and attention.

So it was part of our original filing, and it was something, you know, it was really an important component for us that we made clear as part of settlement discussions because of volatility and the costs there.

Q. Does this create any -- this may. You may defer this to an accountant, but does this create any GAAP accounting issues or do you have -- and let me pose a hypothetical here.

If the Commission were to approve this on a pilot basis, a year or so, and then we -- since you're filing about every 18 months, we have a chance to review these things frequently. And in the next case we were to reject it, say it's really not working the way it is, wouldn't that create an issue on for -- the company on a earnings perspective?

I mean, you mentioned that this could, in response to Commissioner Oshie's question, that out of 80 million dollars of annual earnings, it could be a 4 or 5 million dollar hit to EPS, earnings per share.

Well, that wouldn't be earnings per share. That would be total earnings. But both from a GAAP accounting standpoint, and let's say the Commission approved, then rejected it, wouldn't that create a real issue for volatility in earnings for your CFO and how Wall Street views your company?

A. If the Commission were to choose to not approve it at some point in the future, it would be important that the opportunity would be there to recover the dollars that are already deferred.

And so if there's an understanding that what's already been deferred would be amortized, then that would not create an accounting issue. But if the Commission terminated it altogether, not allow recovery of deferred amounts, then that would create a problem.

Q. And what does the settlement agreement say on that point? Let me see. I'm referring to page 8 at the bottom of the last sentence.

Doesn't it say, Mr. Norwood, parties have the right to a full review of the actual amounts sought for the deferral amortization for each year?

So doesn't that mean that the Commission would have the opportunity to undertake a full review on both the issue of the deferral and the amortization and approve it at a future date?

A. I think going forward in any rate case, I think all the issues are open for the Commission to review, the parties to review. I think my understanding of this sentence here was that the fact that the mechanism's set up we want to defer these costs doesn't mean that they're automatically approved. So there's opportunity for all parties then to look at all the costs that are current deferred to ensure that they're (inaudible).

Q. Ms. Daeschel, Mr. Schooley, is that your understanding, too?

BY MR. SCHOOLEY:

A. Yes, it is. I think it's intended to look at the expenses or the deferral of any one year and say, well, it looks like you overspent this by 2 million dollars, and so instead of 8 million dollars you're seeking for recovery, it will be 6 million.

I think the important thing on this page 8 is the accounting set up here is posting the deferrals into account 182.3, which is the regulatory assets as approved by the Commission, that is putting the blessing on the Commission of recovering those costs in future rates, once they've been deferred.

That can be the issue of amount and prudence of the amount, but it is -- the Commission would be setting up a regulatory asset and the approval of recovering that in rates in the future. If you terminated it, it would be on a prospective basis.

COMMISSIONER JONES: Okay. Judge Moss, that's all I have.

JUDGE MOSS: All right. Let's turn to Chairman Goltz and see if he has questions.

BY CHAIRMAN GOLTZ:

Q. Thank you. One of the advantages of this format for questioning is we can ask all the witnesses the same question at the same time.

The disadvantage is that you tend to go over things over and over again. My colleagues asked some things. I'm going to be touching on some of those same issues.

The first -- little background. Do you have the written testimony up there? Mr. Norwood, if you could turn to Ms. Andrews' testimony on page 7 of her written testimony. And there is a pie chart which basically shows what went in to the company's original rate request.

Do you have that?

BY MR. NORWOOD:

A. I do have it.

Q. And basically it says that -- the question, which is over on page 6, is, "What are the primary factors driving -- driving the company's need for an electric increase?"

And the response is -- says, "Refer to illustration number 2," and illustration number 2 is the pie chart. It says that increased net plant investment is 64 percent of what's driving it. Production and transmission expenses, 18 percent. And distribution and other expenses, 18 percent.

You have to look at footnote 2 to get the complete picture, as I understand it, because footnote 2 indicates that the 64 percent of the pie that is dedicated to increased net plant development also includes the return on investment.

So it's my understanding that the original filing you asked for a return on equity of 10.9 percent. Your current authorized return is about 10.2 percent.

A. That's correct.

Q. And so that extra seven-tenths of a percent on the expanded rate base would find its way to that 64 percent slice of the pay?

A. That's correct.

Q. So my question -- that was my first question, although I guess 64 percent hardly sounds like a slice. What is -- if -- if you were to -- if Ms. Andrews were to do a simpler pie chart for the settlement, what would it look like? Can you tell us that? Or if you were to do the chart.

A. Actually, we wouldn't be able to do that, because although we did specify some things, like we reestablished some power supply costs, we eliminated some tree trimming costs and some other adjustments, we don't have things like the cap structure, the ROE, and we also don't have rate base. So you need to know what is the increase in rate base that drives the additional investment, what is the ROE and so on.

Q. But you do know or the parties agree about in general terms the amount of the rate increase attributable to in effect new plant or replacement?

A. No, there wasn't agreement. In fact what went on in the room is we had certain pieces. The other parties had their own pieces. In the end we came up with the same number, but we all had different pieces.

Q. So the sums are the same, but what went into them is different?

A. Yes.

Q. So that gets to my next question, which is that our -- the Commission's statutory obligation is to ensure that rates set by utilities are -- and these are statutory terms -- fair, just, reasonable and sufficient.

So are all the parties in agreement that, if we approve this settlement, we will have fulfilled our statutory duty?

BY MR. SCHOOLEY:

A. Yes.

BY MR. NORWOOD:

A. Yes.

BY MR. SCHOENBECK:

A. I believe so.

BY MS. DAESCHEL:

A. Yes, I believe so.

Q. So two yeses and one "I believe so." Don't read anything into this question, but if we were to reject the settlement, as I understand it, the settlement is filed shortly before staff, Public Counsel and intervening testimony; is that correct?

BY MR. SCHOOLEY:

A. Correct.

Q. If we were to reject the settlement, how long after that rejection would it take for staff, Public Counsel and intervenors to file their testimony? Not binding you to this, but give us a ballpark.

JUDGE MOSS: Something short of a week?

MR. SCHOOLEY: Be nice to have at least six weeks.

BY CHAIRMAN GOLTZ:

Q. Six weeks?

BY MR. SCHOENBECK:

A. I think the problem is going to be -- you're running into the holidays. Absent the holidays, I would have certainly said four weeks, but it's difficult.

Q. Ms. Daeschel?

BY MS. DAESCHEL:

A. Yeah, it's difficult to give a ballpark number. I guess I would probably say at a minimum six weeks as well, given the other cases our office is involved in currently.

Q. Okay. I'd like to go to the settlement stipulation on page 4. And there's a topic there of administrative and general expenses, which although some parts of the sum were not agreed to apparently for this one, parties agreed to an adjustment of 1.235 million dollars.

But the details of what went into that is also not agreed to among the parties; is that correct?

BY MR. SCHOOLEY:

A. That's correct.

BY MS. DAESCHEL:

A. That's correct.

CHAIRMAN GOLTZ: The court reporter, when I ask a question and they all nod their heads, are you getting all that?

Q. So Mr. Schooley, am I to gather from that that, looking through the 13 individual items labeled A through M on page 4, you may -- Commission staff may have an idea of -- of how that 1.235 million dollars is allocated among those 13 items, and Mr. Norwood may have a different idea; is that safe to say?

BY MR. SCHOOLEY:

A. That would be safe to say. I would also say that we may have had A&G items that are not on this list that are not itemized here, but -- and then we may not agree at all with certain of these items. So it's the total dollar amount is roughly an agreed-upon deduction from what the company was requesting.

Q. Okay. Do you agree with that, Ms. Daeschel?

BY MS. DAESCHEL:

A. Yeah, I would agree that all of these components. The total dollar amounts for each weren't agreed to by the parties. So yes, I would say that's fair, how the parties would agree, whether or not one is appropriate or they contest the amount versus another.

Q. And were all of these adjustments adjustments to existing expenditure levels by the company or were some of these adjustments to proposed additional expenditures by the company?

A. I believe that all of these were to the existing expenditure levels. Many I do not think -- and the parties can correct me if I'm missing one. I don't believe any of these were pro forma adjustments.

Q. Is that correct, Mr. Norwood?

BY MR. SCHOOLEY:

A. I would agree with that basically.

Q. All right.

BY MR. NORWOOD:

A. I guess I have trouble with that -- the question. I guess I would say that we've agreed for settlement to this number, but we certainly don't agree with these issues or that you would take the number and divide it up.

And so I think that's the difference of our piece would -- for this would have been very small, and so this represents one of those differences.

Q. So I gather from that, sometimes in rate cases we -- at least we like to think of it this way, we would make an adjustment or agree to it for staff or hold a counsel adjustment, and expect that going forward things would be done that way.

But I gather that you don't get that benefit out of this stipulation, because we don't have an agreement about how things are to be done going forward?

A. I think we have agreement on what we're going to do in terms of our accounting and training and all of that. But there's a lot of these issues where I think they just represent a difference of opinion.

For example, allocation of executive labor costs and non-utility operations. We do allocate costs to our non-utility operations. The issue here is that the difference of opinion as to how much that is.

And so it's not really a rule or law issue. It's a difference of opinion, which we'll probably see that next case, also.

Q. And I gather it's the same -- are we going to see the same with the level of executive incentive compensation?

A. Most likely, yes.

Q. And we can talk to that in a minute. Something about charitable donations. Isn't the law pretty clear on that?

A. It is. So the number here would be very, very small, only to the extent that there's -- someone booked it to the wrong account would there be a number there.

Q. Okay. Let me ask you about the A&G, item E which is extrapolation of certain A&G, that's administrative and general expense, error rates identified through Avista's internal accounting audit.

So Ms. Daeschel, I know this is Public Counsel's issue last time or the time before, both. And I appreciate that work you did on that.

But is -- is -- is the -- are you saying that Public Counsel didn't do the audit, he did a partial audit and extrapolated, and you came to a number which informed your deliberations or settlement deliberations?

BY MS. DAESCHEL:

A. Yes, that's accurate.

Q. And so in some of those are -- E talks about extrapolation of certain A&G error rates, and the next one talks about incorrectly booked A&G expenses identified during discovery.

What's the difference between those two?

A. I can help explain that difference. So it is separate, and there could potentially be -- I could see how you could potentially have some overlap between those, because, of course, incorrectly booked A&G expenses were cases where Public Counsel or another party may have identified costs in this case that were inappropriately booked.

But what we did with the extrapolation was to identify that the audit had found a certain percentage of errors in the accounts that they reviewed in their sample. So I believe that number was 9.8 percent.

Q. I'm sorry. 9.8?

A. 9.8 percent of the transactions that they reviewed were incorrectly booked. And so for some of those it was not a matter of it being inappropriately booked to rates. In some cases it was simply being booked to the wrong utility account.

So it wasn't an instance of rate payers were paying when they weren't supposed to. But so this attempts to identify further percentage that was booked inappropriately to non-utility, recognizing that there was only a subset reviewed in that audit.

That in fact it probably, if you looked at all of the A&G accounts, total A&G expenses for the test year, that there would be more than that specific amount identified in the audit that we're talking about.

So this extrapolation attempts to come together with a number of what that would be, a dollar amount. And that's not specifically identified for E here, but it is incorporated into that 1.235 million.

Q. So can you give some examples of the errors that -- that were -- have been corrected that, because they're corrected, would be the benefit of rate payers, what would be some examples?

A. Sure. I guess an example would be, yeah, charitable donation. That should have been booked to a non-utility rate, and had inadvertently been booked above the line, and the company would probably be able to agree that in instance, yes, that should have been booked below the line. That's an example, pretty easy one.

Q. And you said that I think it was a year ago at the last rate case where there was this training that was implemented and audit implemented, and you said you didn't think it was something that could be fixed within one year.

That kind of surprised me, because a year ago I thought it was something that would be fixed within one year.

What would be an example of things that couldn't be fixed within a year?

A. I think it's just a matter of Mr. Norwood identified being able to have the training in place, so going to the level of the employees needing to understand when you do book a cost, how you determine whether it's going to be in a utility versus non-utility account.

So going through that process of educating the employees and realizing I don't think that it took place until probably a few months after the last settlement went into effect. So just realizing there is some catch-up time in terms of educating employees and seeing those changes come about.

Q. So Mr. Norwood, is any of this difficulty due to the fact that you do business in three jurisdictions and you have different requirements?

BY MR. NORWOOD:

A. Yes. Some of the errors that have occurred, they may be charged to the wrong state or to the wrong service, so electric and gas. But as to your question in terms of the training and two years versus one year to fix all this, this review was based on 2010 numbers.

The training was early 2011, so going forward I would expect what we are seeing is less of an issue going forward.

May I comment on the extrapolation issue?

Q. Sure.

A. I think it's really important. As part of the settlement in the last case, the company agreed to have our audit group, which functions independently and reports to the chairman, do the audit.

They conducted the audit per the settlement agreement. In the audit report they made it clear you cannot extrapolate these results to dollars, because statistically the audit wasn't driven to capture dollars. It was driven to capture how many errors are occurring.

So you need a different type of analysis to try to capture dollars. And so I think it's important to know that people trained in this, in applying statistics to subsets of data, made it very clear you cannot extrapolate these numbers to arrive at a bigger number.

Q. But in a sense for the purposes of our settlement, that's not relevant, because you're all agreeing to a number?

A. We agreed to an aggregate number, and the parties agreed that the numbers related to these issues that were raised in our discussions.

Q. So can you just briefly describe the Wattson campaign? It's W-a-t-t-s-o-n. And what was the problem with that?

A. My understanding is we typically -- those dollars related to Wattson, which Wattson is a -- how to describe it? It's a person in a dog suit who promotes energy conservation, primarily to the younger generation.

My understanding is that funding really should come from the energy efficiency tier. And I believe that some of the dollars were being charged to the non --

Q. General rate?

A. Yeah, and so we need to fix that.

Q. And so that's being fixed going forward?

A. Yes.

Q. And the next item after that is various expenses with dual shareholder rate payer benefits. Is this another one of those where there's disagreement between the company and your staff, Public Counsel?

BY MR. SCHOOLEY:

A. I'll address that. That's such things as board of directors costs and things like that. So there would be some shareholder benefits and some rate payer benefits as companies, publicly held companies do need boards of directors.

So it'd be as much a question of allocation between the two more than any errors. Staff may have come up with a different number than what public company or the company would.

BY MS. DAESCHEL:

A. And I would just add this as the Public Counsel. In my joint testimony, we identify this as one of the pieces of the A&G adjustment that we believed in. And one of the things, just an example that we would record, the shareholder costs, our rating agency meetings and fees, share valuation analysis, and the reports, press releases relating only to corporate earnings. So those were some of the things we felt were appropriate to share between rate payers and shareholders.

Q. No rate payer benefit for press release on corporate earnings?

A. Also shareholder there. That's all we're saying.

Q. So let me go up to the -- the first two A&B, which is, "Allocation of executive labor costs, non-utility operations, and levels of executive incentive compensation."

These are, I believe, areas that Public Counsel has been active in substantially. And we heard about at the public hearing this morning, we heard about levels of compensation.

So it is -- Ms. Daeschel, is the -- is Public Counsel's concern with the allocation of salaries between utility and non-utility functions or is it also concerned, and does this settlement address, in your view, the overall levels of compensation?

A. It does address in terms of overall levels of compensation, those that rate payers should be required to pay for. So I guess to answer your question, the specific settlement looked at in the context of how much is charged to utilities versus non-utilities and where that sharing should appropriately lie.

And so we ended up by -- or it was our belief that it should be -- less should be allocated to Avista Utilities. And so that was how we came up with this particular adjustment to executive costs.

Q. But that's sort of allocating the compensation pie as opposed to criticizing the size of the pie.

A. That's correct.

Q. So in the -- has Public Counsel in the past been

focusing on the size of the compensation pie as well?
A. Yes, very much so.
Q. And if this were to go to hearing, would that be an issue in Public Counsel's testimony or can you say?
A. I guess I couldn't say at this point, but it's certainly an issue. We've always taken a strong look at it, and it's an issue that we're continuing to take with Avista Utilities.
Q. And then the levels of executive incentive compensation, what does that include?
A. I think I'll defer this one to staff, because I don't have that close at hand.
BY MR. SCHOOLEY:
A. I think that was concerning a lot of the -- I know the supplemental executive retirement plan is completely out of readiness. And the other executive compensation, I think the company itself had taken out considerable amounts of the bonuses, especially for the top executives.
So I think this may have been maybe part of what's just itemized here, but the company may not have as much dispute with that as with some other ones.
Q. So as I understand -- Mr. Norwood, maybe you can answer this. As I understand, executive compensation is several components. There's a base salary, there's a non-equity incentive pay, and then an equity stock

incentive?

BY MR. NORWOOD:

A. That's correct.

Q. And so where in your filing, as the cases you filed, how did those get allocated to rate payers or shareholders?

A. Ms. Andrews addresses it in the testimony, but I'll tell you what we included in the case. First of all with the long-term incentive plan, which relates to the equity portion, all of that is excluded. We don't include it in our request at all.

And then there's the short-term incentive piece for officers. Part of it's related to earnings-per-share targets, and that part is also excluded.

The only piece that is included is related to managing O&M and customer satisfaction and liability. So I'm going to give you a ballpark. It's probably 30 percent of the total short-term opportunity roughly.

And then on the base pay, we allocate a portion of the base pay to the extent the officers deal with the non-utility. That's allocated to non-utility people included in the case.

Q. On executive compensation, I think I read somewhere, and it may not be in the record, but the shareholders vote on executive compensation packages.

Do you know?
A. My understanding is just recently in the last year or two there was a provision where there will be a vote by shareholders on compensation, yes.
Q. Is that the annual shareholders meeting?
A. I'm not certain, but I believe that's correct, yes.
Q. And has that happened yet?
A. We had one this year, but I don't think that there was a vote this year. I think it's a provision that takes some time to get to the point where you actually vote. I may --
Q. And --
A. And I'm not certain upon that.
Q. Okay. Let me ask you that. And so to the deferred accounting mechanism that was -- has been discussed for maintenance costs that falls in various departments, there are specific FERC accounts that are included in this, and I believe you said, Mr. Norwood, that in the Idaho version of this there were more accounts.
A. That's correct.
Q. So -- and these are considered maintenance accounts, so my question is -- is hypothetical. If there would be an EPA requirement that would require some upgrade for pollution control efforts at Coal Strip, would those be

in or out?

A. If it's some kind of requirement to upgrade something and involved capital, then that would be a capital investment, would not be tracked. If -- if, for example, we included some new equipment to deal with nitrous, NOS, there's some -- some additional chemicals we use to -- to work in that equipment, and that would be an operating cost, so that would also not be included.

So there may be some maintenance costs that would come in to some EPA requirement, but I can't think of any at this point.

Q. Mr. Schooley, do you have any other?

BY MR. SCHOOLEY:

A. No, the FERC accounts identified here are the maintenance accounts, and they're clearly identified in the uniform system of accounts. The operation accounts are different accounts, and they are also clearly identified. So there are pretty -- there are very clear instructions about what is maintenance and what is operations.

Q. So now this is -- I wasn't quite sure if -- Mr. Schooley, you may have mentioned this, but Puget Sound Energy would also have this potential issue; isn't that right?

A. True.

Q. They don't have this mechanism. They have a piece of Coal Strip, but they don't have this mechanism nor have they requested this?

A. I'm debating whether we're crossing lines here.

Q. Okay. Well, is it -- is it -- I should say they don't have one.

A. I can't even go there.

Q. I'm saying they don't have a mechanism in place approved now.

A. These accounts are part of their power cost adjustment mechanism.

Q. Okay. Then let me ask this. This mechanism has a division. Would it -- if Avista were not in for a rate case for three years, would there be adjustments to rate payer bills or would they just get adjusted at the next rate case?

A. There would be no effect on the rate payer bills. It would only be running through the income statement to balance sheet.

Q. And so the time when it would be rolled into rates or adjusted would be at the next general rate case, whenever that is?

A. Yes, for whatever the expenses for that test period would be, not -- there wouldn't be any adjustment necessary for any years that were prior to the test year.

I mean, there will be amortizations, for instance, and deferrals prior to a test year if they didn't come in for three years, but it would only be the test year level of expenses that would be at issue in the rate case.

Q. But would there be deferred expenses? If the base expenses were 5 million and the actuals were 6 for three years, when would that other 3 million dollars be recovered?

A. Starting the year after a deferral has been made, it begins amortizing as well. So that amortization does not just stay there until a new rate case. It amortizes on schedule regardless of whether there's a rate case.

Q. Oh, there is -- in this there are separated from this rate case a decoupling proposal that is not before us today. But if you can answer this in general terms, is if we were to approve a decoupling mechanism on the electric side in this non-bifurcated proceeding, would that have any impact on this settlement in some way? Would some rates have to be adjusted for that; do you know?

A. No rates would have to be adjusted in my understanding, certainly not coming out of this settlement. If it were approved, there may be an effect on rates in the future.

Q. Is that your understanding, too, Mr. Norwood?

BY MR. NORWOOD:

A. Yes. In the decoupling proposal that's been proposed by the coalition, they're proposing to establish a baseline which would be based on the stipulation. But that would not create a change in rates right away. The change would come later after you apply the mechanism to see if there's a surcharge or fee rate to customers.

BY MS. DAESCHEL:

A. I just want to weigh in on this one.

Q. Sure.

A. I just want to point you to page 16 on the joint testimony of the parties where we do address this issue, whether the decoupling mechanism is approved in a bifurcated proceeding and how that would impact the settlement.

So the settling parties recommend that if the Commission does order future consideration or adoption of elected decoupling or similar, that shouldn't occur until the next general rate case.

And I think paramount to that is that if elected decoupling is approved, we believe that it would impact or the ROE in this case should be implicated, and that parties will have a chance to review that, and so I think it would open up a settlement in terms of the ROE component.

Q. And that -- you say settling parties. That does not include the NWC?

A. That's correct.

Q. So -- okay. Thank you. I have --

BY MR. NORWOOD:

A. May I respond to that, please? Her comment that it would reopen the settlement, I don't think -- whatever decision the Commission makes going forward, whether there's an ROE adjustment or not, it doesn't have to reopen the settlement.

Q. It would be a new rate case?

A. It would be a new rate case or if there's an adjustment necessary, we can determine what that adjustment is and maybe going forward or defer it, address it going forward without reopening anything.

Q. So I have a question. And I don't think I need to get Mr. Ebert on the line, but -- so either the parties -- the witnesses can answer. Maybe Mr. Roseman can answer.

But first, Mr. Norwood, is the -- there's additional amount for low-income assistance built into this settlement of about half a million dollars; is that right?

A. Yes, 550,000.

Q. Now, that -- and in other words, the overall proposed rate increase of 20 million dollars, the 500,000 of that, would that go back to a subset of rate payers?

BY MR. SCHOOLEY:

A. No, that's not exactly correct.

BY MR. NORWOOD:

A. No. If you go to appendix 3, the stipulation, Exhibit 1. At page 2 of 6, appendix 3, page 2 of 6. Okay. Here you can see in column D is the proposed increase at 20 million.

Q. Yes.

A. If you go over to column H, you would have increased funding for LIRAP, which would be under tariff schedule 91 of 244,000. So the total electric increase for the general and LIRAP is twenty million two forty-four.

And so then of this amount, you would have an extra amount going back to those qualifying low-income customers that receive benefits.

Q. So in other words, the -- the extra money for low income is being funded in a way different from the general rate increase?

A. That's right. It comes -- the additional 550,000 comes from three places: 244,000 from the electric side, and then a hundred and twenty-six thousand from the gas side, which would be on another page, and then we're shifting some dollars from conservation education and other programs to direct funding for LIRAP. That's a hundred and eighty thousand. Those three pieces total 550.

Q. Okay. So of that amount, does this -- any of that extra money for LIRAP, any of that in the company's direct case or is this just as a result of the settlement discussions?

A. None of that was in the direct case. It's a result of settlement.

CHAIRMAN GOLTZ: I have no further questions.

JUDGE MOSS: Anything else? Mr. Oshie? Mr. Jones?

COMMISSIONER JONES: No.

BY COMMISSIONER OSHIE:

Q. Yes. Thank you. I just want to follow up on that last answer, Mr. Norwood, that there's a hundred and eighty, and I didn't really hear the last digit is, you know, plus or minus, but just say round a hundred and eighty thousand is going to be shifted from conservation to LIRAP.

Can you explain that?

BY MR. NORWOOD:

A. It's conservation education.

Q. Conservation education?

A. Part of that -- part of that is the Wattson campaign. Sorry.

CHAIRMAN GOLTZ: It's the dog.

BY COMMISSIONER OSHIE:

Q. Yeah.

A. And also part of it is some events like senior education, some of those events. We'll do less of that and more LIRAP.

Q. So the money that's now being collected that you either have collected or you will collect from rate payers for conservation will be shifted over to provide the LIRAP benefits?

BY MR. SCHOOLEY:

A. No. The money -- this is conservation education that is within the LIRAP program, education of low-income groups. That money was just being shifted within LIRAP from education moneys to direct moneys.

COMMISSIONER OSHIE: Okay. Thank you.

JUDGE MOSS: Nothing further?

CHAIRMAN GOLTZ: No.

JUDGE MOSS: All right. Anything from the parties? All right. Then that will conclude this portion of our proceedings, the settlement hearing. And we will then recess until 6 o'clock. Yes. 6 o'clock this evening.

We will reconvene in this room for our second public comment hearing of the day for those who wish to attend. And with that we'll be off the record for now.

(The proceedings were concluded at 04:35 PM.)

C E R T I F I C A T I O N.

STATE OF WASHINGTON
COUNTY OF KING

I, Kathleen Hamilton, a Certified Shorthand Reporter and Notary Public in and for the State of Washington, do hereby certify that the foregoing transcript of the settlement hearing on NOVEMBER 8, 2011, is true and accurate to the best of my knowledge, skill and ability.

IN WITNESS WHEREOF, I have hereunto set my hand and seal this 17TH day of NOVEMBER, 2011.

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KATHLEEN HAMILTON, RPR, CRR, CCR

My commission expires:
APRIL 2014