BEFORE THE WASHINGTON STATE

UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, vs. PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY, Respondent.	DOCKET NO. UE-050684 Volume VII Pages 634 to 816
In the Matter of the Petition of PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY For an Order Approving Deferral of Costs Related to Declining Hydro Generation.	DOCKET NO. UE-050412

A hearing in the above matter was held on January 17, 2006, from 9:30 a.m to 3:40 p.m., at 1300 South Evergreen Park Drive Southwest, Room 206, Olympia, Washington, before Administrative Law Judges ANN E. RENDAHL AND THEODORA M. MACE and CHAIRMAN MARK H. SIDRAN and COMMISSIONER PATRICK J. OSHIE and COMMISSIONER PHILIP B. JONES.

Joan E. Kinn, CCR, RPR
Court Reporter

The parties were present as follows:

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INDEX OF EXAMINATION

INDEX OF EXHIBITS

350	647
351	647
352	647
353	647
354	647
355	647
356	647

DAVID L. TAYLOR

361-T	703
362	703
363	703
364	703
365	703
366	703
367	703
368	703
369	703
370	703
371-T	703
372	703
373	703
374	703
375	703
376	703
377	703

MARK T. WIDMER

391-T	749
392	749
393	749
394	749
395	749
396	749
397	749
398-T	749
399	749
400	749
401	749
402-C	749
403	749
404	749
405	749
406	749
407	749
408	749
409	749
410	749
411	749

MARK R. TALLMAN

421-T	781
422	781

0641

1	423	781
2	424-C	781
3	425-C	781
4	426-C	781
5	427	781
6	428-C	781
7	429-C	781
8	430-C	781
9	431	781
10	432	781
11	433-C	781
12	434-C	781
13	435-C	781
14	436-C	781
15	437-C	781
16	438-C	781
17	439-C	781
18	440-T	781
19	441	781
20	442	781
21	443	781
22	444	781
23	445	781
24	446	781
25	447	781

0642

448	781
449	781
450	781
451	781
452	781

BENCH REQUESTS

19	694
20	695
21	769
22	775
23	775
24	808

P R O C E E D I N G S

JUDGE RENDAHL: We're back on the record on Tuesday, January the 17th, in Docket Numbers UE-050684 and UE-050412, PacifiCorp general rate case, and before we get started let's take brief appearances from the parties beginning with the company.

MR. GALLOWAY: Good morning, Your Honor, my name is George Galloway, I will be appearing on behalf of PacifiCorp today and tomorrow.

JUDGE RENDAHL: Thank you.

MR. KEYES: Good morning, I'm Jason Keyes from Stoel Rives representing PacifiCorp.

JUDGE RENDAHL: Thank you.

MR. SANGER: Good morning, my name is Irion Sanger, I'm here for the Industrial Customers of Northwest Utilities.

JUDGE RENDAHL: Thank you.

MR. FFITCH: Good morning, Simon ffitch for Public Counsel.

JUDGE RENDAHL: And for Staff.

MR. TROTTER: For Commission Staff, Donald T. Trotter, Assistant Attorney General.

JUDGE RENDAHL: Thank you.

Good morning, everyone. My understanding is we're starting with cross-examination of Mr. Duvall; is

DIRECT BY GALLOWAY)

that correct?

MR. GALLOWAY: That is correct, Your Honor.

JUDGE RENDAHL: All right, well, let me give the oath to the witness and we'll get started.

(Witness GREGORY N. DUVALL was sworn.)

JUDGE RENDAHL: Please go ahead.

Whereupon,

GREGORY N. DUVALL,

having been first duly sworn, was called as a witness herein and was examined and testified as follows:

D I R E C T   E X A M I N A T I O N

BY MR. GALLOWAY:

Q. Good morning, Mr. Duvall. Has prefiled direct testimony that's been marked as Exhibit GND-1T been filed on your behalf?

A. Yes, it has.

Q. And are Exhibits GND-2 through GND-10 appended to your direct testimony?

A. Yes, they are.

Q. And has prefiled rebuttal testimony which has been previously marked as GND-11T been filed on your behalf?

A. Yes, it has.

Q. And is Exhibit GND-12 appended to your direct testimony?

A. Yes, it is.

Q. Are there any corrections you would like to make in your prefiled direct or rebuttal testimony?

A. Yes, there are.

In my prefiled direct on page 1 --

JUDGE RENDAHL: I'm sorry to interrupt, but I will note for the record that the exhibits that you're referring to, Mr. Galloway and Mr. Duvall, have been marked. Do you have an exhibit list with the number markings on them, Mr. Galloway?

MR. GALLOWAY: I'm sorry, I was going from the wrong column.

JUDGE RENDAHL: That's okay, they're both proper descriptions, but I just wanted to make sure you do have the exhibit list.

MR. GALLOWAY: I do have the exhibit list, and I was reading from it.

JUDGE RENDAHL: Okay.

MR. GALLOWAY: Would you like me to put the official exhibit numbers on the record?

JUDGE RENDAHL: I will just note that they're

Exhibits 331-T through 342 that you were just referring to, and so from now on if we can refer to the exhibit numbers, that would be useful.

MR. GALLOWAY: Sorry.

JUDGE RENDAHL: Okay.

A. So on page 1 of Exhibit 331-T, line 5, my title has changed since I filed the testimony. My title is now Director of Integrated Resource Planning and Regulatory Strategy.

BY MR. GALLOWAY:

Q. And is there a correction to your rebuttal testimony that you would like to make?

A. Yes, there is, and that's Exhibit 341-T, and on page 7, line 23, the sentence at the very end that begins:

> It also double counts the hydro endowment since the same hydro resources are included in the hydro ECD credit are included in the pre-merger ECD credit.

I would strike that sentence.

Q. With those corrections, if I were to ask you the questions set forth in your prefiled direct testimony and rebuttal testimony, would your responses be the same as set forth therein?

A. Yes, they would.

Q. And are Exhibits 332 through 340 and Exhibit 342 true and correct to the best of your knowledge?

A. Yes, they are.

MR. GALLOWAY: Your Honor, at this time I would offer Exhibits 331-T and 341-T together with Exhibits 332 through 340 and Exhibit 342.

JUDGE RENDAHL: Are there any objections to admitting those exhibits?

Hearing no objection, Exhibits 331-T through Exhibit 342 will be admitted.

MR. GALLOWAY: And, Your Honor, if it's appropriate at this time, I note that Staff and Public Counsel have proposed to offer Exhibits 343 through 356, and the company has no objection to any of those exhibits.

JUDGE RENDAHL: Do you wish to move admission of those exhibits?

MR. TROTTER: Yes, Your Honor.

MR. FFITCH: Yes, Your Honor, thank you.

MR. SANGER: Yes, Your Honor, I would clarify that Exhibits 352 through 356 are ICNU cross-exhibits.

MR. GALLOWAY: Sorry.

JUDGE RENDAHL: So noting there's no objection from the company, what have been marked as Exhibits 343 through 356 are admitted.

MR. GALLOWAY: Your Honor, Mr. Duvall is prepared for cross-examination.

JUDGE RENDAHL: Thank you. And I understand we're going in the same order we did last week, which is beginning with Staff and then Public Counsel and then ICNU; is that correct?

MR. TROTTER: Yes.

JUDGE RENDAHL: Okay, well, please go ahead, Mr. Trotter.

MR. TROTTER: Thank you.

C R O S S - E X A M I N A T I O N

BY MR. TROTTER:

Q. Good morning, Mr. Duvall.

A. Good morning.

Q. I'm going to be asking you questions about your rebuttal testimony, 341-T. Please turn to page 4, and on lines 5 through 10 you discuss the hybrid allocation model, and you indicate that the MSP participants worked on that model but were unable to come up with a consensus on how it should work. Do you see that?

A. That's correct.

Q. And with respect to consensus, you're talking about consensus of all of the MSP states including Utah

and Oregon?
A. Yes.
Q. The Oregon Commission has required the company to develop a hybrid allocation model for that state's use; is that right?
A. They required us to develop a hybrid method for reporting purposes only.
Q. And as a comparator to results from the Revised Protocol?
A. Yes, that's correct.
Q. The Utah Commission has not done so, has it?
A. No, they have not.
Q. The company has not worked solely with this Commission Staff to develop a hybrid model, has it?
A. No, it has not.
Q. Or a control area based model of any sort; is that right?
A. Well, the company has worked with all parties, and this Staff has been involved in those -- in the work groups. Well, at least I think Public Counsel was, I'm not sure if Staff was involved, but they were all invited to participate in the development of the hybrid model.
Q. My question was whether the company worked solely with Washington Commission Staff to develop a

control area based model?
A. There was some discussions following our last order that culminated in a report in April of last year, and that was working with the Washington parties. Other than that, it's been work that would be done with a broader group.
Q. Beginning on line 13, page 4, and going to the next page, you describe certain items that you characterize as complexities of developing a control area model; is that right?
A. Yes.
Q. And you are discussing those in the context of what the MSP participants discussed as regarding areas where they could not reach consensus; is that right?
A. That's correct, they're simply areas that we -- we spent a lot of time looking at a hybrid model, and these are the areas that different parties found to be difficult to come to some kind of agreement, and we found them very subjective.
Q. So your answer to my question is yes?
A. I don't recall the question.
Q. Turn to page 5, line 4, one issue you talk about is how to establish fair transfer prices between areas for capacity, energy, or reliability services; do

you see that?

A. Yes, I do.

Q. And by areas, you mean control areas?

A. Well, in the context of the hybrid, that was correct, there was --

Q. And that's the context of -- excuse me, I cut you off.

A. Yeah, there were two issues with regard to I guess once you assign resources to particular loads, then you have to look at the load resource balance for each of those groups and look at if you have surpluses or deficits in the different groups, you have to figure out ways to make hourly transfers. So there are really two things involved in that interchange. One is the methodology on how you make those assignments, and the second one is actually how you price it once you have determined the methodology.

Q. And regarding the pricing, it was the Commission Staff's position that market prices be used; isn't that right?

A. I don't actually recall their position. That sounds right though.

Q. And what was -- you also talk about issues of dividing up resources between control areas; do you recall Commission Staff's position on that issue?

A. Well, I'm not sure what their position was on that. I think at the last MSP meeting I think there was some voice of support by Staff for the hybrid as it was in that form, and so I guess their position would be that it should be assigned by control area to the extent that could be done. However, there are certain contracts that we have, one large contract which is an exchange contract where we have -- we provide power in the East Control Area, and we receive power in the West Control Area, and that obviously can't be assigned that way, it has to be assigned all to one control area, so there's some movement there. There were also some resources that were in question as to what do you do with the Dave Johnson and Wyodak plants, which were former Pacific Power plants, but they're located in the Eastern Control Area. And the other one that was contentious was the Cholla Unit 4, which has an exchange on it that makes it a winter -- it looks like a winter resource. Most of the power we get from that plant given the combination with the summer-winter exchange comes to us in the winter, and that was seen as a winter season resource, and some folks thought that that was attributable to the Western Control Area even though it resided in the Eastern Control Area.

Q. And by some folks and by "contentious", you're talking about the MSP parties and the MSP process?

A. Yeah, and I think --

Q. On page --

A. -- there was one other item that I recall, and that was the sale to Southern Cal Edison, which was delivered in the Eastern Control Area, and I believe Washington's position, Washington Staff's position that that should belong to the west.

Q. On lines 23 to 24 on page 5, you say:

Trying to identify each and every benefit by resource would be an impossible task.

Do you see that?

A. Yes.

Q. The company uses its IRP process to determine what resources are needed, where they are needed, and why they are needed, correct?

A. Yes.

Q. In the RFP process, the company identifies the specific parameters for needed resources including delivery points, correct?

A. That's better directed to Mr. Tallman.

Q. In Utah the company also identifies what resources it needs, where they are needed, and why they are needed when it files for certificates of necessity to construct projects in that state; is that right?

A. I didn't understand who -- the company determines what it needs on a system basis. If it's located in Utah, then there's a process that the company needs to go through to get a certificate, and that process is with the Utah Public Service Commission.

Q. And in that process, the company identifies what resources it needs, where they are needed, and why they are needed, does it not?

A. Well, they have done that in the process of the integrated resource plan, and once they have identified that, they go and ask for a certificate.

Q. And in the certificate process, the company identifies what resources it needs and why it needs the resources and where it needs the resources, doesn't it?

A. I believe those are all parameters. I think Mr. Tallman is the one who's more familiar with the certificate process.

Q. The company identifies what resources it needs and why when it makes presentations before the company's board for a decision to do a project, does it not?

A. I'm sure that's true.

Q. Turn to page 6, lines 17 through 20, you talk

about the control area based allocation method being studied at length by MSP participants and was found to be unacceptable for the reasons contained in your direct and rebuttal testimony; is that right?
A. That's correct.
Q. Commission Staff never indicated that an appropriately developed control area based allocation method was unacceptable, did it?
A. No.
Q. This Commission to your knowledge has not made a finding that a control area based allocation method is inappropriate, has it?
A. No, they haven't, but in the past they have been faced with Pacific Power which had multiple control areas and used the rolled-in allocation methodology.
Q. The point of your testimony here is that you could not reach consensus in the MSP; is that right?
A. That's correct.
Q. Turn to page 8 of your rebuttal, and here you're talking -- you're providing testimony in response to what Staff calls its Amended Revised Protocol method; is that right?
A. That's correct.
Q. And you recognize that that's a transitional method to be used only for this case per Staff's

testimony?

A. Yeah, that's per Staff's testimony, correct.

Q. On lines 20 through 22, you address the adjustments made by Staff for Currant Creek, Gadsby, West Valley, and certain Utah qualifying facilities or QF's; is that right?

A. That's right.

Q. And you understand that Mr. Buckley's Amended Revised Protocol method removes the fixed costs related to Currant Creek, Gadsby, and West Valley resources and includes the variable costs; is that right?

A. I believe that's right.

Q. And the variable costs are still being allocated to Washington via the Revised Protocol method, is that right, under his Amended Revised Protocol allocation?

A. Yeah, and that's one of the problems that's identified with that method is that Mr. Buckley has removed fixed costs but has taken all of the benefits that the low cost energy provides to the system through the allocation of the Revised Protocol, which is in my opinion not fair.

Q. You refer to the Utah QF facilities, Staff removed those facilities; is that right?

A. I believe they removed the cost of those

facilities that exceeded the average system cost.
Q. And the company did not provide a demonstration in Washington through an IRP process or otherwise that the energy from these Utah QF projects were needed in Washington, deliverable to Washington, or least cost for Washington, did it?
A. The company demonstrated that they were needed for Washington. In terms of the determination of need for the company, it's done by looking at the total system loads and total system resources and looking at maintaining a 15% planning reserve margin. Once that results in a new resource on a total system basis, that's when the company would add a new resource. It does not do that on a control area basis.
Q. Does that complete your response to my question?
A. Yes.
Q. The QF contracts are contracts that the company is required to sign under the Public Utility Regulatory Policy Act or PURPA; is that right?
A. That's correct.
Q. And when the company developed the contract prices associated with the Utah QF's, the company used Utah's avoided cost, not Washington avoided cost; is that right?

A. That's correct.
Q. So is it fair to say that these contracts were entered into under PURPA as PURPA is administered in Utah?
A. Yes, that's correct.
Q. Turn to page 10, and beginning on line 5 you begin to discuss the Staff's treatment of Mid-Columbia contracts; do you see that?
A. Yes, I do.
Q. On line 13 you state that Staff's allocation of these resources to the Western Control Area is done without showing their dedicated transmission facilities to transmit that power to the Western Control Area; do you see that?
A. Yes, I do.
Q. The delivery points into the company's system from the Mid-Columbia dams is in the Western Control Area, is it not?
A. Yes.
Q. Are they not?
A. Yes, they are.
Q. I covered this territory with Mr. MacRitchie, and I would like to ask it of you, just one moment.
On second thought, I'm going somewhere else, and that is to Exhibit 343.

A. Okay.
Q. And this is the company's 2004 IRP update it filed with the Commission on November 4th of 2005?
A. Right, that's the Staff cross-exhibit.
Q. Yes.
A. Okay.
Q. And this represents the latest product of the company's IRP process?
A. Yes.
Q. Is that right?
A. Yes, it does.
Q. Turn to page 1, which is the executive summary, and in the second to last paragraph, the company notes that:

Since filing the 2004 IRP in January of 2005, PacifiCorp has updated inputs and assumptions. Updates to the latest resource forecast reveal that the gap between loads and resources is diminishing.

Do you see that?
A. Yes, I do.
Q. Turn to page 12.
A. I'm there.
Q. And figure 2.1 is the updated what is called

the topology for the 2004 IRP update; is that correct?

A. Correct.

Q. And the line, the longest line drawn that divides the chart separates the company system into what PacifiCorp calls the Western Control Area and the Eastern Control Area, correct?

A. That's correct.

Q. And so the -- and the circles, are those called bubbles?

A. Yes.

Q. And so the bubbles on these through the left and upper left of that line is the Western Control Area, and on the lower right would be the Eastern Control Area?

A. That is correct.

Q. Turn to page 66, table B-2.

A. Okay.

Q. And this shows the updated loaded resource balances for the system; is that right?

A. Yes, it does.

Q. And you show in the upper half of the page the Eastern Control Area, and the next category is Western Control Area?

A. Yes, that's how it's shown.

Q. I would like you to now look at Exhibit 344, which is a spreadsheet that the company provided to Staff.

A. Okay.

Q. Am I correct that this spreadsheet supports the figures shown on table B-2 that we just looked at?

A. I know there was a request that came through to the IRP group, and it asked for the detailed information behind one of the tables. I was looking in the response to see if that was the table, but I --

Q. Could you accept it subject to check?

A. That looks like the right thing, yes.

Q. Okay. And would it be correct that if we added up the various resources that are shown on Exhibit 344, they would trace back to table B-2?

A. If that's the backup for B-2 it should.

Q. So, for example, turn to page 2 of Exhibit 344, excuse me, it's denominated at the bottom page 3 but it's page 2 of the spreadsheet.

JUDGE RENDAHL: Mr. Trotter, page 2 of 5, is that what you're looking at?

MR. TROTTER: Page 2 of 5, yes.

JUDGE RENDAHL: And that's page 4 on the lower right-hand corner?

MR. TROTTER: Yes.

JUDGE RENDAHL: Okay.

A. Okay.

BY MR. TROTTER:

Q. So if, for example, if you look about two thirds down the page we see several entries for Gadsby?

A. Yes, there's six of them.

Q. Okay. And if we added up the values for those items, they would total the amounts shown on Exhibit 343, table B-2?

A. On the table B-2, I don't see Gadsby, so I don't think there's -- I don't think you can sum up those six numbers and come to anything that matches on B-2.

Q. I'm sorry, they would add up to -- well, we can at least agree subject to your check that the source of the figures shown in table B-2 in Exhibit 343 is the spreadsheet in Exhibit 344?

A. Yes.

Q. Let's go back to table B-2 for a moment, page 66 of Exhibit 343.

A. Okay.

Q. And we see under both the east and west categories about 7, 8 lines down the word transfers?

A. Right.

Q. And just looking at the east part of the table for 2006, you show transfers of 454 megawatts?

A. Correct.

Q. And then in the west part of the chart, transfers are negative 454 megawatts; do you see that?

A. That's correct.

Q. And that means that there are net transfers into the Eastern Control Area of 454 megawatts and 454 megawatts of transfers out of the west; is that right?

A. That's what this table shows, that's how it's reported in this table, yes.

MR. TROTTER: Those are all my questions, Mr. Duvall, thank you.

JUDGE RENDAHL: Mr. ffitch.

MR. FFITCH: Thank you, Your Honor.

C R O S S - E X A M I N A T I O N

BY MR. FFITCH:

Q. Good morning, Mr. Duvall.

A. Good morning, Mr. ffitch.

Q. You have already testified this morning that the PacifiCorp electrical system includes two separate control areas, PacifiCorp East and PacifiCorp West; am I understanding correctly?

A. Yes, that's correct.

Q. And Washington is located in the West Control Area, right?

A. Yes, it is.

Q. And does PacifiCorp at times use its generating resources located in the East Control Area to help serve firm loads located in the West Control Area?

A. Yes, it does.

Q. Could an unlimited amount of power generated in PacifiCorp East be used to serve firm loads in PacifiCorp West, or are there transmission constraints between the two control areas?

A. Well, it's a fairly complex question, and I guess to limit the use of eastside resources to the west by looking at transmission constraints is not valid. There are abilities to move power physically, especially at times when we have forced outages or maintenance outages with the Jim Bridger plant. We also have, and I mentioned this before, we have an exchange contract that actually moves 800,000 megawatt hours from the Eastern System to the Western System throughout the course of the year. That's called the South Idaho Exchange. This is all talked about in my direct testimony. We can also redispatch the system. If we put a resource on the east side, it will redispatch the system to move some of the existing power to the west, and that's another way that we can put a resource in the east to serve the west. And the final way is that we can take that power to market on the east and do a simultaneous sell-buy where we sell on the east and buy in the west. So there's many ways we can do that.

Q. Well, let's go back to my basic question. Can an unlimited amount of power generated in the East Control Area be used to serve firm loads in the West Control Area, or are there any constraints?

Do you want to break it up into two questions?

Can there be an unlimited amount of power from the east generated in the east to be used to serve western loads?

A. Well, I think physically the answer would be no. But, you know, resources in our Eastern System can support loads in other ways, as I have described.

Q. All right.

In daily prescheduling of the operation of its system, is it PacifiCorp's normal practice to commit to serve firm loads in the West Control Area with an amount of generation from the east that exceeds the amount of firm transmission capacity between the two areas?

A. Well, again, the resources are dispatched in a way that is the most economic for the system. And to the extent we don't -- we don't move any particular resource to any particular load. We dispatch resources to meet our system loads in the least cost manner.

Q. Well, I'm hoping you can answer this with a yes or no. I understand you've got some explanation, but I feel like this is a yes or no question.

In your daily prescheduling, is it the company's normal practice to commit to serve firm loads in the west with an amount of generation from the east that exceeds the firm transmission capacity?

A. Oh, I guess the answer to that is no, we would not schedule power from the east to the west in amounts that would exceed our rights to get power from the east to the west when you're talking about physical transfers.

Q. And if you try to do that, that would violate reliability standards of the Western Electric Coordinating Counsel, wouldn't it?

A. I have no idea.

Q. In its integrated resource plans, does PacifiCorp plan to meet firm load -- excuse me, I will withdraw that question. Let me rephrase it.

In its integrated resource plans, does PacifiCorp plan to meet firm load in its West Control Area using generation from its East Control Area that exceeds the amount of firm transmission capacity between

the two areas?
A. Well, the way we plan our system is to look at our loads and resources, I explained this earlier, and look at a planning margin on top of that, and we use 15%. So we say, you know, we, if we have a need to add a resource based on our system load and resource balance, then in the IRP we will then take a look at where we should place that resource to come up with the least cost, least risk plan. So we look at various portfolios to do that.
Q. But in that plan, do you plan to meet western load with eastern generation that exceeds the firm transmission capacity between the two areas?
A. Well, not on a physical basis, no.
Q. Now this is something that Staff has just touched on, there are three plants, the Currant Creek Plant, the West Valley lease, or three resources, pardon me, three resources, Currant Creek, that's C-U-R-R-A-N-T, the West Valley lease, and the Gadsby project, and those are all located in the East Control Area, right?
A. Yes, they are.
Q. And these three resources add up to 845 megawatts; is that right?
A. Subject to check.

Q. And these are new natural gas fired combustion turbine generating facilities that the company has recently acquired, correct?

A. Yes, they are.

Q. And they're located in Utah?

A. Yes, they are.

Q. Can I ask you to please take a look at Public Counsel Exhibit 347 or Public Counsel cross-exhibit that was identified for you, that's Data Request 143. Do you have that?

A. Right.

Q. And that asks you to:

Identify the total amount of firm transmission capacity that PacifiCorp is currently able to use to transfer power from its East Control Area to its West Control Area. If the quantity varies seasonally, please provide monthly amounts.

Correct?

A. Correct.

Q. And the answer provided by the company is:

PacifiCorp can transfer from east to west up to 204 megawatts during heavy load hours and up to 454 megawatts

during light load hours.
Correct?
A. Yes, and that's describing transmission, firm transmission capabilities. It doesn't take into account the exchange I have already talked about, it doesn't take into account the ability to redispatch the system or make simultaneous sell-buys.
Q. All right.
Now when are the heavy load hours referred to here?
A. Heavy load hours are 6:00 a.m. to 10:00 p.m. Monday through Friday I believe.
Q. Monday through Friday or Monday through Saturday?
A. Monday through Saturday, I'm sorry.
Q. So in other words, when scheduling operations of its system, PacifiCorp can not commit to use more than 204 megawatts of generation from its East Control Area to serve firm loads in its West Control Area during heavy load hours?
A. No, I don't agree with that. The Eastern System is valuable in meeting system loads through a variety of ways that I have said, and it's not limited to what we can physically move between control areas.
Q. On a physical basis it is limited to 204

megawatt hours; is that correct?
A. That's correct.
Q. And that represents a little less than 25% of the 845 megawatts of the new natural gas fired generator capacity that we just talked about from those three plants, correct?
A. Yeah, the math is correct.
Q. Can you look, please, at Exhibit 351 identified for you.
A. Yes.
Q. And that is page 30 of Appendix C of the company's 2004 Integrated Resource Plan, correct?
A. That's correct.
Q. And it's true, is it not, that this page shows peak loads of 4288 megawatts for the West Control Area during fiscal year 2006; is that correct?
A. That's correct.
Q. And that's on the top line in the west column under the -- in the peak column, correct?
A. That's correct.
Q. And another math question, you would agree that the 204 megawatt maximum firm transmission capacity or physical capacity we just referred to represents less than 5% of that 4288 figure, does it not?
A. In terms of it dividing the 200 by the 4200,

I presure that's correct.

Q. Please look at Exhibit 349, this is Public Counsel Data Request 145; do you have that?

A. I do.

Q. And this asks you to identify the total amount of firm transmission capacity that PacifiCorp was able to use to transfer power east to west prior to the merger with Utah power; isn't that right?

A. Yes, it is.

Q. And your response states:

Prior to the merger, Pacific Power & Light had 600 megawatts of east to west transfer rights between the control areas.

Correct?

A. Correct.

Q. So is it true that PacifiCorp today actually has a smaller amount of firm transmission capacity to move power from its East Control Area, including Utah, to its West Control Area, including Washington state, compared to prior to the merger?

A. Well, this is really comparing apples to oranges. In 1989 or prior to the merger, there was no such thing as, you know, rights that a merchant had on his transmission facilities. It was the order FERC 888 which has separated the two. Back in these old, you know, late '80's, if you owned transmission, you owned the rights to that transmission, whatever that transfer capability was. And this, as I understand it, this came from our operations people and represented the ability to move across the transformer at Jim Bridger. Jim Bridger was a plant in the Western Control Area, and the only part of the Eastern Control Area that was part of Pacific Power at the time was Wyoming. So this represented the ability to move Bridger power or move power out of the Wyoming control area to Bridger.

Q. All right, but isn't it --

A. At that point we had constraints west of Bridger, so it's kind of a meaningless number.

Q. This is a physical capacity number?

A. Yeah, across the transformer.

Q. It does exceed the current physical capacity of 204 that we have talked about, doesn't it?

A. They're not comparable.

Q. Did Pacific Power & Light have existing generation resources that it used to transfer power from east to west prior to the merger? I think you have just answered that in part.

A. Yeah, Pacific Power had some resources in Wyoming that to the extent, as it is today, if Bridger had some forced outages, they could move some of that power into the Western System.

MR. FFITCH: All right, thank you, Mr. Duvall, I don't have any further questions.

JUDGE RENDAHL: Okay, Mr. Sanger, has ICNU waived cross for this witness?

MR. SANGER: Yes, ICNU has waived cross for Mr. Duvall.

JUDGE RENDAHL: Okay, so the estimates I had for you, Mr. ffitch, of an hour and 15 minutes were radically reduced.

MR. FFITCH: Yes, Your Honor.

JUDGE RENDAHL: Thank you very much.

Is there any redirect for this witness?

MR. GALLOWAY: There is, Your Honor.

R E D I R E C T   E X A M I N A T I O N

BY MR. GALLOWAY:

Q. Mr. Duvall, Mr. Trotter asked you about some of the complexities involved in adopting a control area approach to allocation; do you recall that?

A. Yes, I do.

Q. And in particular he asked you about the, among other things, the issue of establishing a transfer price for transfers between the two control areas for allocation purposes; do you recall that?

A. Yes, I do.

Q. And he indicated that Staff had favored a market price for those transfers; is that correct?

A. That's true.

Q. Could you explain to the Commission, please, some of the real world complexities that exist in respect to the transfer price issue and why reasonable people might disagree over whether to use market prices or some other measure?

A. Okay. So, well, as we went through the hybrid development, we actually looked at four different types of pricing. One was, in terms of market prices, it was looking at not only there were -- there were prices on the sellers' side and prices on the buyers' side, you have the interchange, and we deemed them sellers and buyers. And so we would look at the sellers' maximum or the buyers' minimum, the sellers' minimum, the buyers' maximum. We looked at embedded costs of the transfer. Part of the difficulties would be in who got what resources to begin with, and if a -- if one of the control areas got more resources of the embedded resources to begin with, they would favor a market price because then they could transfer the excess embedded cost resource at a market price which they would believe is higher than embedded cost. And the opposite would be true for the entity that would not get a full compliment of resources who would normally be a buyer, they would favor some embedded cost transfers or embedded cost price transfers. So there was quite a bit of controversy over even if you used a market, what market price to use.

Q. In the course of this exercise, did the MSP parties look at holding company systems that have transfer pricing mechanisms among the holding company members?

A. Yes.

MR. TROTTER: I will object to the question, this is beyond the scope of direct.

MR. GALLOWAY: He asked about transfer pricing and the Staff position, I'm just following up on that.

MR. TROTTER: Specifically, Your Honor, the company did not -- objection to holding.

JUDGE RENDAHL: Could you repeat the question for me.

MR. GALLOWAY: My question was, and it's on the issue of the Staff's position on transfer prices, as to whether the company and the MSP parties looked at practice among holding companies on transfer prices.

JUDGE RENDAHL: I recall some discussion about the MSP, but I don't recall any discussion of holding company and transfer prices.

MR. GALLOWAY: Well, he was asked about transfer pricing and about the Staff position on those.

JUDGE RENDAHL: All right, the objection is overruled, you may go ahead.

BY MR. GALLOWAY:

Q. Did you look at how other companies that had multiple operating companies used transfer prices?

A. Yes.

Q. And what is the established method that MSP parties found for those sorts of transfers?

A. It was to use embedded cost.

Q. And what's the philosophical rationale for using, if you took that side of the argument, embedded cost rather than market pricing for transfer prices?

A. Well, I think the rationale was to be able to sort of share the savings amongst the parties.

Q. All right. And this is philosophically not an easy issue to resolve, is it?

A. No, it's not.

Q. And in the course of the MSP process, did the parties come close to resolving it?

A. No, they didn't.

Q. Okay. Does a hybrid or control area approach also require you to allocate existing transmission facilities and rights?

A. Yes, that was one of the issues.

MR. TROTTER: Objection, Your Honor, that's beyond the scope of cross. This is also asked and answered in his direct testimony.

MR. GALLOWAY: I will withdraw the question.

BY MR. GALLOWAY:

Q. You were asked in cross about dividing resources?

A. Yes, I was.

Q. Can reasonable people disagree as to an initial allocation of resources in a hybrid or control area approach?

A. Absolutely.

Q. And how can reasonable people disagree on that issue?

A. Some of the things I described, that there were some pre-merger Pacific resources that were in the Eastern Control Area, so there's disagreement among who would get those. There was a wholesale sale which was called the Southern Cal Ed sale which was delivered in the Eastern Control Area but was originally contracted for prior to the merger by Pacific Power, so there was disagreement about that. There was disagreement about the Cholla APS exchange which was located in the east but was a winter resource, and given that the west is a winter peaking control area and the east is a summer peaking control area, some folks thought it was more appropriate to assign that to the west instead of the east where it resided.

Q. If you were to establish transfer prices in a control area or a hybrid model, does it have to be done hourly?

A. Yes, it does.

Q. How complex is it?

A. Very complex.

Q. Mr. Buckley has testified that one of the important attributes of an allocation system is that it is administratively simple. In your work on the transfer price model, would that satisfy a goal of administrative simplicity?

A. I don't think it would even come close.

Q. And would it cause the model to be considerably more complex and contentious than the Revised Protocol?

A. Yes, it was, and there were parties who indicated that.

Q. In the debate between the hybrid and

rolled-in approach, is Oregon similarly situated with Washington?

A. Yes, they are.

Q. And was Oregon an initial proponent and strong advocate of a hybrid system?

A. Yes, they were.

Q. And yet they ultimately went along with the Revised Protocol?

A. Yes, they did.

Q. In response to Mr. Trotter's questions about the Staff's proposed Amended Revised Protocol, you indicated that you didn't think it was fair for the Staff to remove the fixed costs of resources but then leave the output of the resources in the economics; could you expand on why you consider that unfair?

A. Well, I think if one were to remove resources and say that they were used for some other entity like the state of Utah that you should fully remove those resources and detriment to the Utah load by the amount of that resource so that Utah would not pay twice, once for these new resources and once for a share of the remainder of the system. And so Mr. Buckley's adjustment or Staff's adjustment didn't do that, it just reduced the cost but didn't -- left the system benefits of the low cost generation in the power cost studies

which were allocated across the system.
Q. So --
A. So Washington got benefits but didn't pay all the costs.
Q. So is it fair to say that as a result of the proposed adjustment Washington is getting the economic benefit of power from plants without supporting any of the fixed costs?
A. Yes.
MR. TROTTER: I will object to the question as leading, Your Honor.
JUDGE RENDAHL: Will you rephrase your question, please.
BY MR. GALLOWAY:
Q. What is the consequences of the Staff's adjustment to the protocol?
A. Well, that Washington would get the benefits of the plants without paying the fixed costs.
Q. Okay.
You also were asked about Staff's proposed adjustment regarding qualifying facilities in Utah, and I believe you indicated that Staff's adjustment is based on the difference between average embedded cost and the cost of the resources?
A. Yeah, that was my recollection.

Q. And is that a fair approach?
A. No, it's not.
Q. Why?
A. Again it's a matter of removing some of the costs without removing some of the benefits. And in particular with QF contracts, as long as they are comparable to other resources the company could acquire and those other resources would be allocated systemwide, then the cost of those QF's should also be allocated systemwide, and that's the way the Revised Protocol deals with new QF contracts.
Q. Is average cost a meaningful measure of anything in regard to a QF?
A. Not for on a forward looking basis.
Q. And normally the prudence or appropriateness of a new resource or a qualifying facility is judged based on contemporaneous avoided cost, is it not?
A. Yes, it is.
Q. And is there any suggestion in Staff's testimony or otherwise that the qualifying facilities exceeded the then contemporaneous avoided cost of the company?
A. No.
Q. And you were asked whether the company applied Utah avoided costs to the pricing of these Utah

situated qualifying facilities.
A. Right.
Q. Does the company have any option other than to use the Utah methodology for Utah facilities?
A. No.
Q. You were asked about the allocation of the Mid-Columbia facilities under the Revised Protocol. Is the treatment of the Mid-Columbia facilities in Revised Protocol, how does that compare to the benefits to Washington that have been enjoyed since the Utah Power-PacifiCorp merger?
A. Well, in the last two allocation methods, which was Modified Accord and the Accord, Washington received a system allocated share of the Mid-C, Mid-Columbia contracts. And in the Revised Protocol, the share of the Mid-Columbia contracts has increased over that level.
Q. So the Revised Protocol is more favorable than the method that's been in place since 1989 as it relates to the Revised Protocol, as it relates to the Mid-Columbia?
A. Yes, yes.
Q. All right.
You were asked a number of questions by both Mr. Trotter and Mr. ffitch about the net transfers

between the two PacifiCorp control areas; do you recall that?

A. Yes, I do.

Q. Do you consider statistics on net transfers the only reasonable measure of the integration of a power system?

A. No.

Q. What other attributes of integration do you think the Commission should consider?

A. Well, I guess the, you know, there's the items that I mentioned already with regard to the exchange that we have to bundle and just the ability to redispatch the system. We have the ability to reach markets on the east side that we can't meet from the west side, so we can make some economic transactions.

I guess one of the things that might help is to look at Exhibit 337, which is in my direct testimony, and that refers back to a study that we had done that looks at changes in load. And so the first part of that shows that when you reduce load in the Eastern part of the system in the, I'm sorry, in the Western part of the system, that the generation changes in both the east and Western part of the system. In fact, the load decreases in the west, and 77%, in looking at the change in generation, 77% of that came from generation in the west, but 23% of it came from generation in the east. And the flip side of that when you look at the east load lost, which is the bottom part of that page, is that when we lost -- we ran a study where we reduced east load by 250 megawatts, the thermal generation changed by 1.4 million megawatt hours, of which 54% of it was in the east and 46% of it was in the west. So I think what that helps demonstrate is the ability to redispatch the system when we have changes in loads or changes in resources. And I think what this also says is that the loads in the west are in part supported by the resources in the east, and the loads in the east are in part supported by the resources in the west.

Q. Is the PacifiCorp generation and transmission system complex?

A. Yes, it is.

Q. Are you aware of a utility in the United States that has a more complex generation and transmission system?

A. No, I'm not.

Q. And is it hazardous to look at only one consideration like east to west transfers in measuring integration benefits?

A. Yes, it is, it's very narrow.

Q. Okay. Maybe as an example of that, could you describe how the Bonneville peaking contract works and how it benefits the system?

A. Yeah. The Bonneville peaking contract allows us to take power from Bonneville. It's about I think it's at 575 megawatts. We can take that really any time, but we mainly take it during heavy load hours. And then the power that we -- and we can take that at multiple delivery points across our system, so it's very flexible. We can take some of that in Washington and Southern Oregon, Central Oregon, different points of interconnection with Bonneville. And then we have also within 168 hours we need to return the power that we took. So it's a net zero on energy, but when we return that power we also have a number of different points that we can deliver that power to as we return it to Bonneville.

Q. Now some people have compared that contract to a pump storage facility, haven't they?

A. Yes.

Q. So you draw it down during the day and then sort of refill it during the night?

A. Right.

Q. And typically where does the power come from to refill the contract during the night time?

A. From our coal plants.

Q. In Wyoming?
A. In Wyoming, some in Utah.
Q. Okay.
A. Eastern Control Area.
Q. So a measure of high load hour transfer capability wouldn't capture any of those benefits, would it?
A. No, it wouldn't.
Q. And if the company hypothetically is able to sell power in the daytime to California at high rates and recover that power at nighttime from the coal plants, there's a substantial economic benefit, isn't there?
A. Yes, there is.
MR. TROTTER: Your Honor, I'm going to object to the continuing leading nature of all of these questions.
MR. GALLOWAY: I will move on.
JUDGE RENDAHL: The objection is granted. I would advise you to work on your questions to make them less leading, please.
BY MR. GALLOWAY:
Q. Are there reasons that looking at only on-peak transfer levels is a misleading measure of system integration?

A. Well, yeah, because the company's operated round the clock, and there's, as we just talked about, the BPA peak contract is one that involves returns of off-peak energy, and that's important.
Q. And you used the word energy, and energy can be different than capacity?
A. Yes.
Q. Mr. ffitch asked you and I think you used the phrase unlimited amount of transfer capability from east to west; do you recall that?
A. Right.
Q. Do you think a standard of unlimited transfer capability is relevant to anything?
A. No.
Q. Are transmission constraints part of the business of any utility?
A. Yes, they are. In fact, I think in a recent Avista case there was Coyote Springs 2, which had transfer limitations, firm transfer limitation of that plant to get to Avista's service territory, and they actually talked in their testimony about these buy-sell transactions and getting non-firm transmission to get that power to be useful, and this Commission found that to be useful for Avista.
Q. Was the Avista testimony that there was no

firm transmission capacity between Coyote 2 and its system?

A. That's my recollection.

MR. FFITCH: Objection, Your Honor, there was no cross-examination about Avista.

MR. GALLOWAY: Well, there was certainly --

JUDGE RENDAHL: Counsel, if you direct your response to the Bench rather than to each other, I would appreciate it.

So if you can respond to Mr. ffitch's objection.

MR. TROTTER: Your Honor, could I just add to that objection so that he can respond to both at the same time?

JUDGE RENDAHL: Go ahead.

MR. TROTTER: Your Honor, this is testimony that the company could and should have put in their direct rebuttal case, not at the last moment on redirect, so we will object on that basis as well.

MR. GALLOWAY: Your Honor, there were 15 or so questions about transfer capability and unlimited transfer capability, and it seems to me an appropriate redirect question to point out that this Commission has found that facilities where there is no transfer capability to be used and useful, and that's the point of these questions.

MR. FFITCH: Your Honor, if I can just respond, the witness himself responded to some of the questions with some explanation, and my concern with the line of questioning from counsel now is that it's moving into more of a direct examination, a much more in-depth kind of exploration of answers that the witness has already given couched in a number of leading questions. So I was prepared to let some of that go on, but we seem to be embarked on a more or less direct examination on this area.

MR. TROTTER: My problem, Your Honor, is this is new information that we simply haven't been able to test, and we won't be given that opportunity.

JUDGE RENDAHL: Well, it appears to me that this is something the parties can argue on brief. If it's something the Commission has done, an action the Commission has taken, then it's something the parties can argue on brief. It is new information, it's a bit beyond the cross-examination scope, and so I'm going to grant the objections, and if you want to address it in your brief as analogous, then it's appropriate, and then there's an ability to respond, but I think we need to move on.

MR. GALLOWAY: Okay, I have no further

questions.

JUDGE RENDAHL: Are there any questions from the Bench?

E X A M I N A T I O N

BY COMMISSIONER JONES:

Q. Let's start with the transmission issue and the control areas. On pages 3 and 5 of your direct testimony, on page 3 you do talk about the PacifiCorp system, PacifiCorp system on a total company basis, and you do state -- I think this is Exhibit 331-T, your direct.

A. Yes.

Q. Could you just read that line I think on line 20.

A. On page 3?

Q. Yes, on page 3.

A. (Reading.)

The company is limited by transmission constraints and operates its system on an integrated basis with two control areas.

Q. Do you still stand by that statement?

A. Yes, I do.

Q. Turn to page 5. PacifiCorp, this is the question of limited transmission rights between the Western and -- basically how you operate the two control areas instead of one. I'm a little, based on the give and take in the questions and answers we have just had, I'm a little confused about how you operate the system. It's the company's assertion that you operate it for resource acquisition and from an IRP standpoint on a systemwide basis, correct?

A. For planning purposes.

Q. For planning purposes.

A. On a systemwide and operation on a systemwide.

Q. Yet -- and you do recognize that there are limited, and you state here, there are limited transmission rights between the Western and Eastern Control Areas, correct?

A. Yes, that's correct.

Q. And you talk about the difficulty. Are these the two primary difficulties that the company foresees of consolidation of control areas, the ERD certification process, and I ask you to address this question in light of the ERO language in the EPACT of '95 about what is proposed in the federal legislation, these are still the two primary constraints of consolidation that you see?

A. Well, I think what, in talking with folks, the response I got to why don't we have a single control area is, you know, there's no gain. There's a lot of work to do it, and there's no gain unless you do something like an RTO sort of thing, so we're -- we would continue to operate our system in about the same manner as we do today even if we had a signal control area. Now we could do that, but as I am told there's really no gain to go through that process.

We do have, one thing I don't think has been mentioned here is we do have the ability, we have what's called our dynamic overlay between our control areas, and so we can actually do load following between our control areas. And so we can send signals from one control area to the other control area to be able to help meet the changes in loads and forced outages and those sorts of things.

Q. Has PacifiCorp considered consolidating its controlled areas as part of the RTO West or what is commonly called now Grid West discussions, and what, if any, impediments to control area consolidation have you encountered?

A. Well, the answer to the first question is yes, as part of the RTO West it would involve consolidation of the control areas. And I think impediments would be just getting all of the folks to

agree to move forward with the arrangements.
Q. And by all of the folks, you mean the adjacent control areas as well that you interconnect with including Bonneville control areas, Avista control areas, Idaho Power, et cetera, et cetera, those adjacent control areas where you have current agreements?
A. Right, what I mean is the participants in the Grid West, which up until recently included Bonneville and Avista I believe. I'm not -- I don't recall if Puget was in or out. But now it's a smaller group, and within that group there would be still consolidation of control areas, and then there's discussions that would need to take place that have already started taking place about how that would integrate with a Bonneville, who is actually looking for other participants to kind of team up with them, and so there would be some seams issues between those sort of two groups.
Q. Let's turn to this hybrid issue for a minute and the Oregon order. I think you stated on the record that, in response to counsel's questions, that the Oregon Commission in January of '05 in order 05021 adopted the Revised Protocol in its entirety; is that your assertion?
A. Yes, it is.
Q. Didn't they also have a couple of

stipulations on that order, in fact two or three stipulations?

A. Well, there was one stipulation with, you know, multiple parts, but it was just one stipulation.

Q. Wasn't one of those stipulations that:

The Oregon parties are to devise a fully functional hybrid method no later than December 1st, 2005.

A. Yes.

Q. Have you done that?

A. Yes, we have.

Q. Could you, this is a Bench request, could you submit a copy of that to the Bench, because I don't think we are in possession of that.

A. We can, and we actually filed that in late November and provided copies to each of our commissions, so.

Q. I'm sorry.

A. We will follow up on that.

Q. I read most of your testimony and that of Mr. Taylor yesterday, and I didn't see that, I'm sorry.

Describe fully --

JUDGE RENDAHL: Before you go on, that would be Bench Request 19, and it would be a copy of the hybrid proposal developed in December if it's not already submitted in the record. If it is, if you all can identify where it is, that would be helpful, thank you.

THE WITNESS: It's not in the record.

MR. SANGER: Your Honor, this is Irion Sanger, ICNU submitted comments on the hybrid report to the Oregon Commission, would it help the Commission if ICNU also submitted those to the Commission here in Washington?

COMMISSIONER JONES: Certainly.

JUDGE RENDAHL: And should we make that Bench Request 20?

COMMISSIONER JONES: Yes.

JUDGE RENDAHL: Okay.

MR. GALLOWAY: Your Honor, I think those are in the record, at least will be.

JUDGE RENDAHL: Well, why don't we clarify at a break where those are and if there's no need for the Bench Request.

Go ahead, Commissioner Jones.

BY COMMISSIONER JONES:

Q. You described some of the difficulties and I think I understand some of those of interexchange pricing, fair evaluation of these exchange contracts that you have, the Bonneville peaking contract, but the

Oregon language seems to be pretty specific in terms of a fully functional hybrid method, and we have some concurring opinion by Commissioner Savage where he goes into some length as to why he supports the hybrid proposal as perhaps superior to the Revised Protocol. What do you interpret this word fully functional to mean?

A. I guess I would interpret it as meeting the policies set out by the Oregon Commission. I think that's the way they couched it in their order. And one of the criteria was that this be a method, to be fully functional would be a method that would allow the company, you know, the opportunity to recover 100% of its costs, and that's I think the one sort of sticking point that was sort of difficult to achieve, but we did the best we could. And we filed that and indicated in our filing letter that we would begin reporting on that January 1st unless we were told otherwise, and we haven't heard back from the Oregon Commission.

Q. When does the company expect to file the next rate case in the state of Oregon?

A. Soon, within a month I believe.

Q. Are you also going to use the Revised -- you're going to use the Revised Protocol, because the Commission has agreed to it, as well as there's another stipulation stating that the revised hybrid method should be submitted as a comparator in any future rate case; is that correct?

A. Right, the revenue requirement will be based on the Revised Protocol, and the hybrid, the numbers will be run through this new hybrid as a comparator for a comparative purpose.

Q. Let's turn to the IRP for a minute, and do I understand it that you are now the manager of the integrated resource program and we will be seeing you in that context in the future?

A. You will, that's a fairly recent appointment.

Q. When is the next IRP due in front of this Commission?

A. We have a schedule to file the next IRP January of next year, mid January.

Q. And you updated the 2004 IRP, which was submitted in January of '05, you submitted an update of that to this Commission what, a month or so ago?

A. Yeah, I think it was early November.

Q. Has the load resource balance either in the East Control Area or the West Control Area changed at all as a result of that update?

A. Yes.

Q. Has it tightened or has it widened in terms

of the difference between the two?
A. The gap has narrowed so that the -- basically the major change between the 2004 IRP and the update was that we were able to defer the gas plant that was planned for 2009, and so our next plant -- and I think we also delayed the coal plant on the east by one year. So the next -- the next major new resource included in our IRP update begins in 2012. There's actually two resources, one is a coal plant on the east side and a gas plant on the west side of our system.
Q. Is it fair to characterize, as I said before, the IRP process was focusing on a total systemwide basis?
A. Yes, it is.
Q. And the breakdown of the Western Control Area and the Eastern Control Area from a load resource balance computation is for reference purposes only?
A. That's correct.
COMMISSIONER JONES: Thank you, that's all I have.
JUDGE RENDAHL: Any other questions from the Bench?
Okay, is there anything more for this witness?
MR. TROTTER: I had a few follow ups based on

Mr. Galloway's, cross on redirect.

JUDGE RENDAHL: Please go ahead.

MR. TROTTER: Thank you.

R E C R O S S - E X A M I N A T I O N

BY MR. TROTTER:

Q. Mr. Duvall, you referenced a Bonneville Exchange power contract?

A. Yes.

Q. What's the expiration date on that contract?

A. 2011 I believe.

Q. You referenced benefits to Washington from Mid-Columbia contracts, and you compared those, your answer was based on a comparison to the "Modified Accord" method which you said, which your counsel said was "in place". Has a Modified Accord been approved by this Commission?

A. No, it has not. In fact, my quote though was as compared to the Accord and the Modified Accord. The Accord was one prior to that.

Q. Again --

A. And while it's not in place with the Commission, it was the method that the company did all its reporting on for several years.

Q. So by in place you did not interpret that to

mean approved by this Commission?
A. No, I did not.
Q. Okay.
Finally, you were asked some questions about QF, treatment of QF's and whether the treatment recommended by Commission Staff was fair or not, and you answered accordingly. Am I correct that you understood questions from your counsel to refer to what are called new QF's under the Revised Protocol?
A. Yes.
Q. Because you understand that the Staff's proposed treatment is the same as the Revised Protocol treats "existing" QF's?
A. That's the treatment, but it's not consistent with the Revised Protocol.
Q. And the term new QF and existing QF are defined terms in the Revised Protocol; is that right?
A. Yes, that's correct.
MR. TROTTER: Nothing further, thank you.
JUDGE RENDAHL: All right, if there's nothing further for this witness, Mr. Duvall, you may step down, and we will take a 15 minute break and come back between 5 after and 10 after the hour, so we will be off the record.
(Recess taken.)

JUDGE RENDAHL: We're back after a mid morning break for the cross-examination of Mr. Taylor.

Mr. Taylor, would you stand and raise your right hand.

(Witness DAVID L. TAYLOR was sworn.)

JUDGE RENDAHL: Please be seated.

MR. GALLOWAY: Thank you, Your Honor.

Whereupon,

DAVID L. TAYLOR,

having been first duly sworn, was called as a witness herein and was examined and testified as follows:

D I R E C T E X A M I N A T I O N

BY MR. GALLOWAY:

Q. Good morning, Mr. Taylor. Will you please state your full name and your position with PacifiCorp.

A. My name is David L. Taylor, I am a Manager of the Regulation Department of PacifiCorp.

Q. Have you filed direct testimony in this proceeding that's been previously marked as Exhibit 361-T?

A. Yes, I have.

Q. And appended to that testimony are there Exhibits 362 to 370?

A. Yes, that's correct.
Q. And do you have rebuttal testimony that's been previously marked as Exhibit 371-T?
A. That's correct.
Q. And is Exhibit 372 appended to that testimony?
A. Yes, it is.
Q. Are there any corrections that you would like to make to your direct or rebuttal testimony at this time?
A. Just one. On page 1 of my direct testimony my business address and my position with the company has changed since this testimony was filed. As indicated, I am currently a Manager of the Regulation Department at PacifiCorp, and my business address is 201 South Main, Suite 2300, Salt Lake City, Utah.
Q. And with those corrections, if I were to ask you the questions set forth in Exhibits 361-T and 371-T, would your answers be the same as set forth therein?
A. Yes, they would.
Q. And are Exhibits 362 to 370 and 372 true and correct to the best of your knowledge?
A. Yes, they are.
MR. GALLOWAY: Your Honor, at this time I would like to offer Exhibit 361-T with accompanying

Exhibits 362 through 370 and Exhibit 371-T with accompanying Exhibit 372.

JUDGE RENDAHL: Are there any objections to admitting those exhibits?

All right, Exhibits 361-T through 372 will be admitted.

MR. GALLOWAY: And, Your Honor, again in respect to the Staff and ICNU proposed cross-examination Exhibits 373 to 377, the company has no objection to their admission.

JUDGE RENDAHL: Is there any objection to admitting Exhibits 373 through 377?

Hearing none, they will be admitted.

MR. GALLOWAY: Mr. Taylor is available for cross-examination.

JUDGE RENDAHL: Thank you.

Mr. Trotter.

MR. TROTTER: Thank you, Your Honor.

C R O S S - E X A M I N A T I O N

BY MR. TROTTER:

Q. Mr. Taylor, is your position the same as stated in your direct?

A. No, I'm currently a manager in the regulation department.

Q. I would like to ask you some questions about your rebuttal testimony, Exhibit 371-T. And at the outset on line 8 of page 1 you indicate that you will provide observations why none of Staff's potential allocation methods meets the objectives of the MSP, and that in your opinion should not be further developed or pursued for that reason; is that right?

A. That's correct.

Q. And the objectives of the MSP are listed in Mr. MacRitchie's direct testimony as well as your direct testimony; is that right?

A. I believe that's correct.

Q. And some of those objectives include avoiding disproportionate cost shifts and to have results of the cost studies be in an acceptable range; is that correct?

A. Those are some of the broad objectives, yes.

Q. Now it's your opinion, isn't it, that the hybrid model the company developed pursuant to the order of the Oregon Commission does not meet the objectives of the MSP either, correct?

A. That's correct, it does not.

Q. And it's your opinion that the fully rolled-in allocation method ordered by the Utah Commission as a comparator to the Revised Protocol in that state does not meet the objectives of the MSP either, does it; is that right?

A. Without the adjustments that are included in the Revised Protocol, a strict rolled-in would not meet those objectives.

Q. And a strict rolled-in is what the Utah Commission has said is to be used as a comparator?

A. As a comparator, that's correct, not as the method they have adopted but as a comparator.

Q. And the Revised Protocol itself allows a commission to depart from the Revised Protocol if the results -- if they deem the results of application of the Revised Protocol unreasonable; is that right?

A. They have that opportunity, and they're encouraged to come before the standing committee to raise issues as to why they think it's not providing reasonable results.

Q. Staff has made no claim in this proceeding that the potential allocation methods it proposed were developed in the context of an MSP or meet MSP objectives; isn't that right?

A. I don't believe they have made that claim, no.

Q. Turn to page 7, I'm sorry, page 3, I apologize, and you state on lines 16 to 17 that one thing you have learned is that everyone has a different

view of cost causation; do you see that?
A. Yes, I do.
Q. The company's view of cost causation is reflected in the IRP's, RFP's, board presentations it prepares before it acquires resources, and company testimony in certificate of need proceedings; isn't that true?
A. I'm not sure that all of those presentations would deal with the issue of cost causation. Cost causation is generally dealt with in the issue of rate setting and revenue allocation proceedings.
Q. So if we find a statement in an RFP or a board presentation prepared by PacifiCorp that says why a particular resource is being acquired, we should ignore that?
A. No, you shouldn't ignore it. My point was that those don't always deal specifically with issues of cost causation. They may deal with issues of need.
Q. Well, have you reviewed the RFP's and board presentation materials that the company created with respect to the projects that are at issue in this case, particularly the new Utah power projects located in the Salt Lake City area, and reviewed those statements and those document as to cost causation?
A. No, I have not.

Q. Is it appropriate for the Commission to rely on those documents and statements when they contain statements of why the company is acquiring a specific facility?

A. The Commission can rely upon those if they choose.

Q. On page 4 of your rebuttal, lines 14 to 16, you state in formulating the Revised Protocol you sought to harmonize as best as you were able the principle-based positions taken by the various MSP participants; do you see that?

A. Yes.

Q. And Utah was an MSP participant; is that right?

A. They were.

Q. Would it be fair to say that the company did not harmonize the positions of Commission Staff?

A. We took the positions of all of the participants in the MSP, and we put together an allocation procedure which best accommodated the positions and views of all of the participating parties.

Q. And you understand that Staff has opposed the Revised Protocol consistently?

A. By Staff you're referring to the Washington Staff?

Q. Yes.

A. I understand that.

Q. And when I refer to Commission Staff or Staff, that is who I am referring to.

A. Okay.

Q. On page 5 of your rebuttal, you cite a Commission order in Cause Number U-78-05; do you see that?

A. I do.

Q. And that order was in what is referred to sometimes as the generic proceeding involving rate design and rate structure for electric utilities implementing PURPA?

A. Yes.

Q. The Commission issued that order on October 29th of 1980; is that right, subject to check?

A. I will take your word for that.

Q. And you provide a quote from page 6 of that order, and that quote is in the context of applying an embedded cost study to set specific rates in particularly between classes, allocating costs between classes of customers; is that right?

A. That's correct.

Q. And in this proceeding we're talking about allocating costs between state jurisdictions, so you're using this order by analogy; is that fair to say?

A. That's correct, I'm just taking the principle laid out here that it's not just a sausage grinder that produces the rates. There's judgment and other things that come into play in supporting the reasons for why we included some of these policy-based modifications to the rolled-in allocation to come to the Revised Protocol.

Q. Okay. And what the Commission is saying here is that it won't implement an embedded cost study strictly, it will avoid mechanical application of the results of a given study and instead exercise its own judgment on how to do interclass allocations in an equitable manner; is that right?

A. That's correct.

Q. And in rate design generally, rate spread and rate design, commissions typically if they see a large disparity in cost contribution between classes of customers, they will use the concept of gradualism to bridge the gap between cost recovery among classes on a gradual basis?

A. That's a very common approach, yes.

Q. There's nothing in the order in U-78-05 or the quote that you have offered the Commission here that says that the cost study itself should seek to avoid disproportionate cost shifts between rate schedules?

A. No, there's nothing in this order that says the study itself should do that.
Q. And that was a goal of the MSP, was it not?
A. It was, and for a very good reason. When you're dealing with in one state an intraclass allocation, you have a common judge who makes the determination at the end, and at that point they can apply judgment. When you're dealing with a jurisdictional allocation, in our case we have six sets of judges, and so it's much more important that the issues of accommodating these policy-based -- a decision on policy-based concerns be handled within the allocation model itself.
Q. Yes, my point was that U-78-05, the Commission was saying, let the cost study speak for itself and the Commission will determine what cost shifting was appropriate through concepts of gradualism or other policies, whereas here the cost study itself, one of its objectives was to do that in the first place?
A. That's right, again because you have to have one methodology that's being adopted by six different commissions as opposed to a common judge making those kind of judgments.
Q. On page 7 of your testimony, you refer to the NARUC cost allocation manual; do you see that?

A. I do.

Q. And you quote from page 77 of the manual where it says, among other things:

Other things being equal, the cost allocation methods used in the case of a utility operating in one state would be equally applicable to a utility operating in two states.

Do you see that?

A. Yes, I do.

Q. That passage you quoted does not address the allocations of cost of service where the electric utility operates in two separate control areas with limited transfer capability between control areas, does it?

A. It's not that specific. It just makes the reference that the principles for allocating costs between state jurisdictions are the same as those for allocating costs within the jurisdiction between classes.

Q. You agree that the manual gives no guidance regarding, specific guidance regarding the context of costs when a utility operates in two separate control areas with limited transfer capability between them?

A. It doesn't go to that level of specificity,

no.
Q. On page 8 of your rebuttal, you are asked the question of whether you have reviewed how other multistate utilities share costs among their states, and you contacted ten different electric utilities; is that right?
A. Well, I contacted more than ten, but there were ten who responded --
Q. At least ten?
A. There were ten who responded back.
Q. Okay. Nowhere in your rebuttal did you discuss the specific operating characteristics of the systems that you are addressing here including location of loads, resources, and transmission system interconnections and transfer capabilities; is that right?
A. No, the point of that inquiry was just to capture the basic concept of whether these utilities used a common resource portfolio and allocated the cost of that common resource portfolio across all the states they serve or whether they took a subset of resources and direct assigned it to specific states. It was to determine that broad context, it didn't go --
Q. You didn't --
A. It didn't go deeper than that.

Q. You didn't go into the details of how those specific allocation methodologies came about, did you?

A. Again, the question I asked was limited to that. Some utilities provided more information than others. Generally just responded back as to whether or not they used a common allocation across the states based on load and energy and whether they allocated the cost of that common portfolio.

Q. You didn't provide the details of how those allocations came about in your rebuttal, did you?

A. I did not. Again, I was just making the general point that systemwide allocation is the normal practice.

Q. Did you read the Commission's order granting the merger between Utah Power & Light and Pacific Power & Light?

A. I have read it at some time in the past, I don't have it directly in front of me, no.

Q. Are you aware of any order of this Commission in which this Commission, involving PacifiCorp, in which this Commission has stated that combining the systems as one is the norm, the expected norm?

A. There are statements from this Commission that talk about the benefit of a -- a common allocation methodology being the benefit. There's statements about preserving the benefits of the low cost hydro for Northwest customers, and there are statements from this Commission about, and the Commission Staff, about operating the system in the lowest cost integrated manner.

Q. Is that your answer to my question?

A. Yes.

Q. Turn to page 9 of your rebuttal right at the bottom, and here you're referring to an example of Puget Sound Energy charging electricity no different in Bellevue, rates no different in Bellevue than they are in Olympia notwithstanding differences that in your opinion likely exist in the cost of distribution facilities used to serve the two cities; do you see that?

A. Yes, I do.

Q. Are you aware that PSE in fact has separate rates for its gas service to the Kittitas County area separate from other areas it serves?

A. I'm not familiar with their gas service, I'm speaking about electric service here.

Q. Are you aware that the rate difference for PSE is due to different cost structures and system characteristics of the Kittitas County area?

A. I'm not familiar with the differences between those areas. I'm just making the general reference that they charge the same for electricity in both places even though they may be different.

Q. Isn't it true that line extension policies for an example are a regulatory and economic tool used to address cost differences in providing electric service?

A. A line extension policy to a degree can mitigate the cost differences between geographic areas, but they only relate to the interconnection between an individual customer and the distribution grid. They don't address the issues of cost differences in the grid themselves, just the connection between the customer and the grid. So they can have some effect, but they don't completely eliminate the differences between geographic areas.

Q. Turn to page 20, beginning on line 17 you address the proposal by Commission Staff to use a different calculation of the system overhead allocator; is that right?

A. Yes.

Q. And one category of costs that this allocator is used to allocate are administrative and general costs; is that right?

A. That's correct.

Q. And can you give us a general description of what type of expenses or costs we're talking about for A&G?

A. A&G costs include salaries for general office employees, they include the cost of operating general office buildings and those type of costs which don't directly -- aren't directly identified with the generation of transmission or distribution functions of the business.

Q. You're familiar with the PacifiCorp Interjurisdictional Task Force on Allocations also known as PITA; is that right?

A. I am familiar with that.

Q. And for a period of time, an allocation scheme known as Accord was used by PacifiCorp; is that right?

A. Yes.

Q. And in the Accord method, the system capacity and energy factors were adjusted by the contribution of the hydro resources in each division; is that right?

A. I believe that's correct.

Q. So, for example, the Pacific division capacity and energy was reduced by the contribution of the Pacific hydro resources and the same for the Utah individual?

A. That's correct.

Q. And the Accord method in that way affected the SO factor since the SO factor was based on the allocation of plant; isn't that right?

A. Yes, it did. Any allocation procedure which would have altered the allocation of the plant would have had an impact on the system overhead factor.

Q. And is it true that Utah found that to be unacceptable and proposed changes to the Accord, and that was discussed within the context of the PITA meetings?

A. That was one of the reasons I believe for the movement from the Accord method to the Modified Accord method.

Q. So your answer is yes?

A. Yes.

Q. On line 14 on page 21, you talk about system overhead costs discussed in the context of the MSP, and you state:

> The primary concern was that system overheads be proportionally shared among the states and that any modifications designed to reflect regional and state public policy concerns did not alter the allocation of system overheads.

Do you see that?

A. Yes, I do.

Q. And is it PacifiCorp's position in this case that the SO factors it proposes, which is to a large extent based on allocated plant, accomplishes that goal?

A. Yes, the primary concern here in the MSP was that when you're looking at modifications to the systemwide common allocation of the resource portfolio that one impact they did not want to have from that was a reallocation or a shifting of the costs of the overheads, of the system overheads of the company. It was felt that we may look at resource cost shift for regional preferences and other reasons, but we didn't want those reflected -- those preferences to alter how we allocated the overall common costs of the company. Those should be reasonably apportioned across all states. That was one of the benefits of the Revised Protocol in that those system preferences or those regional preferences were dealt with through the cost differentials, which did not alter the original allocation of cost.

That was also a concern when people looked at doing things like tiered rates with the base incremental allocation that was looked at for a while. It was considered when we looked at using load detriments to apportion the cost of resources. One concern in all of those was that if they caused a shift in the allocation of overhead costs that we should look at another methodology, just a simple rolled-in allocation methodology to allocate those overhead costs. They did not want a distortion of that as we tried to achieve the regional preferences that were reflected in the final allocation method.

Q. Turn to page 22, lines 12 through 15, you indicate that:

> There was an increase in the SO factor that was not caused by disproportionate weighting of each state's share of system capacity energy, rather it is the result of the movement away from divisional to system allocation of pre-merger plant.

Do you see that?

A. I do.

Q. The movement away from divisional to system allocation of pre-merger plant was initiated when Utah adopted a fully rolled-in cost allocation method for setting Utah rates; is that right?

A. It was for Utah, it hadn't been adopted across all jurisdictions until the development of the

Revised Protocol.

Q. The movement away from divisional to system allocation that you're referring to in your testimony was in part caused by Utah's decision to go with fully rolled-in; is that right?

A. The movement away was caused by the collective agreement of the signing parties to the Revised Protocol to use a rolled-in allocation system as the starting point and then use other mechanisms to deal with the regional preferences in other issues such as that.

Q. Turn to page 24, and on lines 9 through 13 you criticize Mr. Schooley's three component SO factor by saying:

It captures the impact of large customers twice, once in distribution plant and again in the customer component.

Do you see that?

A. I do.

Q. Is it your contention that distribution plant and customers grow at similar rates through time, and therefore considering both in an allocation factor is duplicative?

A. It's my point there that in a state where you have a substantial portion of the load serving only a few customers, such as we have in Wyoming with its large industrial base, in Idaho where we have one very large customer, or in the FERC jurisdiction where it's all a few very large customers, that that situation is reflected both in the share of distribution plant, because the distribution associated with those customers is either zero if they're transmission delivery or rather small in comparison to their load if they take distribution delivery, so that's reflected in the distribution part. Also the fact that there's fewer customers is a fact that, you know, in the state of Idaho about 40% of the load is one customer, so putting the customer factor into that allocation dramatically reduces the allocation of overhead to Idaho. So my point here was the impact of those large load single customers impacts both the share of distribution plant and the portion of the customer factor, so reflecting them both in the allocation, you're giving those particular states a double benefit from that.

Q.   Turn to Exhibit 373, and here Staff asked you to provide certain data regarding system characteristics for each fiscal year March 2001 through March 2005; is that right?

A.   Yes, they did.

Q. And your response is on a CD, but it also indicates where on the CD you can find the information that's requested; is that right?

A. That's correct.

Q. Turn to page 3, excuse me, Exhibit 374, and this was prepared by Commission Staff excerpting data from Exhibit 373; is that right?

A. I believe that's correct.

Q. Were you able to confirm that Staff accurately reported these data?

A. I didn't go back and redo their calculations, but I don't take exception with the numbers that are here.

Q. And just looking at comparing Washington and Utah for the, and it's in the shaded lines, from 2001 to 2005 Washington customers increased the rate of 3, increased 3.08%, in distribution plant 3.36%; is that right?

A. Could you show me specifically where we're looking here?

Q. Exhibit 374, the Washington column, the 3.08 is in the first shaded line of numbers, and the 3.36 is in the second shaded numbers.

A. Oh, okay, I see. Where it's shaded in mine I can hardly read the numbers, but I see it now, thank you.

Q. Okay.

And for Utah, customers increased 11.08% and distribution plant increased 26.48%; is that right?

A. That's correct.

Q. And during that same time frame, California, if we look at California, its number of customers grew 4.5% but distribution plant actually decreased by a little over 1%; isn't that right?

A. I can't read that number, but I will take your word for it.

Is there a point we're trying to make from this?

Q. I think we did, so.

A. Well, then I would like to respond beyond just your question if I could.

JUDGE RENDAHL: You will have an opportunity in redirect if your counsel chooses to, but if there is no question pending, other than what's been asked --

THE WITNESS: Fair enough.

MR. TROTTER: That concludes my cross, Your Honor.

JUDGE RENDAHL: Mr. ffitch.

MR. FFITCH: Thank you, Your Honor.

C R O S S - E X A M I N A T I O N

BY MR. FFITCH:

Q. Good morning, Mr. Taylor.

A. Good morning.

Q. Simon ffitch with the Office of Public Counsel.

Would you please turn to page 3 of your rebuttal testimony, which has been marked as Exhibit 371, and turn to or look at line 3, please. Do you have that?

A. Mm-hm.

Q. And there you state that Washington customers benefit from each of the modifications to what would otherwise be a straight rolled-in allocation method, correct?

A. That's correct.

Q. And you go on to say that Washington is projected to be the largest beneficiary of the Revised Protocol allocation methodology; is that right?

A. That's correct.

Q. And there you mean by comparison to the straight rolled-in allocation method?

A. No, it's both, there's two comparisons, compared to the straight rolled-in method and also compared to the Modified Accord method which has been used for reporting purposes in Washington for a number of years. So they are projected to be the largest beneficiary in comparison to both of those measurements.

Q. Now rolled-in allocation can be modified substantially by changing various allocators, correct?

A. That's correct.

Q. For instance, in the Accord methodology, state income taxes including Washington's public utility excise tax were allocated on a system basis; isn't that right?

A. I believe that's correct.

Q. In the Revised Protocol on the other hand, state income taxes from states with income taxes such as Oregon, Montana, and Utah, are allocated on a system basis, correct?

A. That's correct, and appropriately so.

Q. But the Washington utility tax along with other excise taxes is allocated on a Situs basis; isn't that right?

A. That's correct.

Q. Are you familiar with how a state determines which portion of utility income is taxed within the state for state income purposes?

A. I suspect different states do it differently. I'm not a tax expert, but I know there's a number of factors that go into determining a state income tax associated with a utility company.

Q. And would you agree those factors would include plant and plant location and other, excuse me, either customers or revenues?

A. Yes, and the fact that it includes plant location is one reason why that they're -- those state income taxes are system allocated, because not all of the value stream is generated within the state where the plant is located.

Q. Can you please identify all the states which have identified rolled-in allocations to be a reasonable allocation method with respect to post Utah-PacifiCorp merger at the time period after the merger?

A. Well, I think the only state who specifically said that they think a strict full rolled-in is the preferred method would be Utah.

Q. All right.

A. But again, we haven't proposed a strict full rolled-in method to be used for the allocation.

Q. Are you aware that during the allocation process, the MSP process, PacifiCorp prepared a study which indicated that once the Pacific division grew faster than the Utah division, the Pacific stand-alone costs would not cross over the rolled-in costs?

A. I'm not specifically familiar with that study.

Q. Prior to the merger, Utah Power owned a series of power plants, correct?

A. Yes.

Q. And in the Revised Protocol, those power plants are allocated across the system so that for Washington customers the Utah pre-merger resources are allocated as much to Washington as are PacifiCorp's pre-merger non-hydro resources? For example, well, those include Bridger or Wyodak and Dave Johnson?

A. That's correct, all system resources are allocated systemwide in the same manner.

Q. It is the case, is it not, that currently the pre-merger Pacific plants have average lower fuel costs for rate making purposes than do the pre-merger Utah generating plants?

A. I'm not certain if that's the case or not. Clearly if you include hydro into the mix the fuel cost is lower, but I'm not certain if the coal plants in the aggregate have lower fuel costs than Utah's plants, I don't know that.

Q. All right.

Will you please turn to page 26 I believe of your rebuttal testimony starting at line 4; do you have that?

A. I do.

Q. And there you begin to address eight factors which Mr. Lott has recommended that the Revised Protocol be required to satisfy, correct?

A. Yes.

Q. And these are factors that or rather you indicate there that you don't agree that the factors necessarily establish the proper standard, right?

A. I said I don't agree that they're necessarily the standard. I also said that I felt that the Revised Protocol satisfied each of them.

Q. All right. And then you go on to discuss how in your view each one of the particular standards is satisfied, correct?

A. That's correct.

Q. Now is it your position that the Commission should not consider any one of the eight factors identified by Mr. Lott?

A. They can consider them, I just don't agree that they're necessarily the defining factors on which the total decision should be made.

Q. All right. So it's not your position that the Commission should not consider any one of these individual factors?

A. No, no. And again I believe the Revised Protocol satisfies each of them.

MR. FFITCH: All right, thank you.

Your Honor, I don't have any further questions for the witness.

JUDGE RENDAHL: Thank you.

Is there any redirect for this witness?

MR. GALLOWAY: There is, Your Honor.

R E D I R E C T   E X A M I N A T I O N

BY MR. GALLOWAY:

Q. Mr. Taylor, Mr. Trotter asked you about the Utah Commission requiring that the rolled-in method be used as a comparator; do you recall that?

A. I do.

Q. Based on your participation in the MSP process, do you know why the Utah Commission wished that comparator to be included and the Oregon Commission wished the hybrid method to be used as a comparator?

A. Well, I suspect Utah requested that for a couple of reasons. One, it was the historical method they had been using, and also for many of the parties in Utah they believe that to be the definitive cost-based approach. Oregon asked us to do the comparator to the hybrid because there were also parties within Oregon who felt that that was the reasonable approach that should be used. Again, in both cases they were just to be used as comparators, not as the foundation for rates.

Q. And do you see anything untoward in a commission requiring a comparator of this sort?

A. No. In other states we have the requirement to match against Modified Accord. I believe that all states were concerned that there not be a dramatic shift in cost responsibility as a result of moving to this common allocation approach, and they just wanted to monitor that.

Q. Do you agree with Mr. Buckley's contention that the allocation method should be adopted without regard to the impacts on one state or another?

A. No, I think it's very important that the impacts of any decision be taken into account. It would probably be foolhardy to try to think you could come up with an allocation procedure or a method that people would follow without any understanding of the impacts and which might have a dramatic shift in cost responsibility.

Q. And that was the reason for your reference to the gradualism in rate spread and rate design decisions?

A. That's right.

MR. TROTTER: Objection, leading.

JUDGE RENDAHL: Counsel.

MR. GALLOWAY: I will restate the question.

JUDGE RENDAHL: Thank you.

BY MR. GALLOWAY:

Q. What was the import of your reference to gradualism in rate spread and rate design decisions in this regard?

A. Well, I think it reflected that there is judgment involved and that rapid movements have generally been avoided in the utility process.

Q. Mr. Trotter also referred to the provision in the Revised Protocol where each commission reserved the right to choose a different path if the circumstances required it; do you recall that?

A. I do.

Q. Do you see anything untoward in a commission requiring the ability to depart from the protocol in the future?

A. No. Again, I think if a commission through their examination feels that it has ceased to provide the results that it suggested, it has ceased to achieve the objectives that have been laid out, they have the right to ask us to revisit it.

Q. Did you view that sort of reservation as tantamount to being a lack of durability in the protocol?

A. No, in fact I think it's one of the things that helps sustain the durability, the fact that if parties view that the Revised Protocol is failing to meet the objectives for which it was established, there's a procedure and a standing committee where you go and review these issues and see if perhaps some small modification needs to be made to the methodology so it stays in harmony with the objectives that were originally established.

Q. Did the company expect that any commission that ratified the protocol would have the ability to bind future commissions?

A. I don't think you can bind future commissions, so I don't suspect that was their intent.

Q. You were asked about cost studies; do you recall that?

A. Kind of.

Q. Would you have the ability to perform a cost study that objectively determines an appropriate basis for an interjurisdictional cost allocation method?

A. I could probably develop several cost studies that would objectively do that from whatever subjectives you're looking at.

Q. So the company didn't make a decision not to perform a cost study, did it?

A. No, we did, we developed a cost study that we believe incorporated cost causation principles as well as public policy issues and regional preferences.

Q. And various parties to the MSP process had very different thoughts on cost causation, didn't they?

MR. TROTTER: I will object, Your Honor, number one, leading, number two, asked and answered in his direct.

MR. GALLOWAY: I will move on.

BY MR. GALLOWAY:

Q. Are you aware of any electric utility in the country that doesn't used a rolled-in allocation method?

A. Well, there are holding companies that have separate operating companies that have specific ownership by state, so they don't use a rolled-in method except in that they have some interchange between their utilities. But from those who have a common set of resources that are used to serve customers in multiple states, all of the utilities that responded to me, with one exception which I really couldn't quite figure out, but at least nine of them used a load based allocation of that common resource portfolio.

Q. And you were asked about the Commission's policy on these issues; do you recall that?

A. I was.

Q. And do you know what the Commission's policy was in the last fully contested rate case in Washington?

A. Yes, their position was that, you know, PacifiCorp has a common set of resources, they serve in six states, and that those resource costs need to be shared across those states.

Q. And was that an order in Case U-86-02?

A. I believe that's correct, yes.

Q. And how many control areas did the company have at that time?

A. I'm not a control area expert, but I believe the Wyoming area was in a separate control area at that time.

Q. Mr. Trotter asked you to go through some statistics comparing customer growth with the growth or lack thereof in distribution plant; do you recall that?

A. I do.

Q. Is there additional information you would like to provide to the Commission in regard to those statistics?

A. Well, just a couple of comments. First is he's only looking at changes in customer growth and distribution plant growth, and the allocation factor, the SO factor, deals with the entirety of investment.

And so it's not just incremental change, it's the total investment, the total number of customers. And so one point was this is only looking at a change over a short period of time. Second point is quite often distribution investment comes in lumpy projects as in the case of Utah where they have done some significant distribution investment over the last few years to improve the reliability of the system. That's not related to specific customer growth at that point in time but to beef up the reliability of the system. So I'm not sure you can look over a period of just a few years and see customer growth and distribution plant growth and say that, oh, they're not that absolutely in sync and so therefore they're not related.

JUDGE RENDAHL: Mr. Taylor, are you referring to Exhibit 374 for the record?

THE WITNESS: I am.

JUDGE RENDAHL: Thank you.

BY MR. GALLOWAY:

Q. What do you think is the more reasonable approach to the issue?

A. Well, again, we are sharing -- the overhead allocation factor is to share the overall common costs of the system that aren't related to any other specific pieces of the business. And over time, since the merger

with Utah Power and Pacific Power, we have used this overall total plant based allocation factor. No one has taken exception with that, it seems to be a method that's worked well and I don't see any reason to change from.
Q. Mr. ffitch asked you about the Revised Protocol's approach to the assignment and allocation of state taxes; do you recall that?
A. I do.
Q. Was there a principal basis for how these matters were resolved in the Revised Protocol?
A. Yes. Again, the same is that state taxes are shared systemwide because the value stream used to determine each state's share of income taxes is not derived from customers in that state alone, so it wouldn't be appropriate to assign the taxes to the revenue requirement. There are other taxes which are more specifically assigned to usage or sales in a state, and those would be more appropriately assigned to that state, but state income taxes would not be.
Q. Was this a subject of controversy in the MSP process?
A. I don't believe this got an awful lot of discussion.
MR. GALLOWAY: I have nothing further, Your

Honor.

JUDGE RENDAHL: Thank you.

MR. GALLOWAY: Oh, I have one more question I forgot.

BY MR. GALLOWAY:

Q. Which was you were asked about whether the Staff had agreed to the Revised Protocol at any point. Anyway, just the one question is, are you aware in your experience in these issues whether the Staff has supported any particular allocation method in the last 16 years?

A. They have indicated perhaps some favorable leanings towards some, but I am not aware they have actually endorsed or supported any particular methodology. That's certainly not been the case in the last 10 or 12 years.

Q. What has certainly not been the case?

A. That they have endorsed a particular allocation methodology.

Q. But they have had concerns about a bunch?

A. Yes.

MR. GALLOWAY: Nothing further, Your Honor.

JUDGE RENDAHL: Thank you.

Mr. Trotter.

MR. TROTTER: Thank you, just briefly.

R E C R O S S - E X A M I N A T I O N

BY MR. TROTTER:

Q. You responded to your counsel regarding an order of this Commission in docket U-86-02?

A. Yes.

Q. That docket occurred before the merger between Pacific Power & Light and Utah Power & Light?

A. It did, but it's the last time this Commission has made an affirmative finding on jurisdictional allocation.

Q. And in the order approving that merger, the Commission expressed concerns about the merging of a higher cost utility, that is Utah Power & Light, with a lower cost utility, that is Pacific Power & Light, didn't it?

A. They expressed those concerns, and we believe we have addressed those concerns in the Revised Protocol.

MR. TROTTER: Nothing further, thank you.

JUDGE RENDAHL: Mr. ffitch.

MR. FFITCH: Nothing further, Your Honor.

JUDGE RENDAHL: Are there any questions from the Bench?

E X A M I N A T I O N

BY COMMISSIONER OSHIE:

Q. Mr. Taylor, just one area. You stated early in your cross-examination by Mr. Trotter that Utah used rolled-in as a comparator, and it seems to me from my understanding of how Utah is using the two methodologies, Revised Protocol and rolled-in, that at least perhaps in the last rate case is it true that Utah used rolled-in methodology to set rates?

A. Let me address the question in a couple of pieces. First of all, Utah has --

Q. Well, maybe you can just answer my direct question, and then you can elaborate. Did Utah use the rolled-in methodology to set rates in the last rate case?

A. There was a cap placed on the revenue requirement in Utah, and that cap rate incorporates a rolled-in result plus an adder. But Utah has adopted the Revised Protocol as the allocation methodology, and in a gradualism procedure they have phased to that you might say by limiting the amount of revenues we can collect in Utah to some percentage above the rolled-in result for a period of time. But that's temporary, and just to reiterate, they have adopted the Revised Protocol as the allocation method.

Q. And it's the cap on the rolled-in methodology that you use to set rates in Utah runs until 2015?

A. I don't have the exact date. It runs for several years. There's also a period of time where it allows for a premium above the Revised Protocol to offset some of the earlier discounts from it.

COMMISSIONER OSHIE: No further questions, thank you.

JUDGE RENDAHL: Commissioner Jones, do you have any questions?

COMMISSIONER JONES: Just a couple following up on Commissioner Oshie's question.

E X A M I N A T I O N

BY COMMISSIONER JONES:

Q. Isn't it true that, and I'm just referring to the language in the Utah order, it states that, you know, after the Commission agreed that the Revised Protocol should be adopted, it said to the effect that it could produce a substantial and unreasonable cost shift to Utah in the near term, and then it went on to state that in order to mitigate such a cost shift in the near term cost impact and the "long run uncertainties" the parties stipulate to rate mitigation measures and conditions to allow parties to withdraw support for the

Revised Protocol should the future unfold in such a way that it produces rates in Utah that are no longer "just and reasonable". So it's a little bit more than what you just described, the parties in Utah have an opportunity to withdraw their support for the Revised Protocol under the just and reasonable standard in the state of Utah, correct?
A. Right, and as do commissioners in other states have that same opportunity.
Q. So each state under the laws of its own state, under the statutory and administrative framework in its own state, have the ability to impose conditions that meet its just and reasonable standard?
A. They have the ability, as in Utah, to determine if the allocation methodology doesn't work any more and propose something in its place.
Q. Turn to page 3 of your rebuttal testimony at the bottom, if you would.
A. Page what again, please?
Q. 3, and that's Exhibit 371-T. I'm a little confused as to why you put the Bonbright testimony quote in here, because if you read this literally, it equates the value with cost and basically says that it's a very subjective determination and it is whatever you determine it to be, and the state commission could

determine cost to be anything it deems to be just and reasonable.

A. Well --

Q. So are you advocating that this Commission adopt such a subjective standard?

A. The purpose of this quote in my testimony was in reflection of the criticisms that the Revised Protocol wasn't a cost-based method and to show that cost causation is very much in the eyes of the beholder. And that was certainly evidenced in the MSP process where there were participants from the six states with very divergent views on what they felt cost causation was. So this was, you know, in direct response to the criticisms in the rebuttal testimony of PacifiCorp where it says it's not a cost-based model because it's not what we think cost basis is. I'm not sure that it's intended to give carte blanche to everybody saying do whatever you want. I think it's indicative of why we had to work so hard to come to an accommodation among the signing parties of the Revised Protocol that everybody felt was cost based and met their other objectives.

Q. I understand, that clarifies my concern.

To the MSP process I have a couple of questions. When was the last meeting in which the

Washington State Staff, the Commission Staff, played a, were not only invited, but attended and played a constructive role in the multistate discussions, what month and year was it?

A. I don't have the date of the last time.

Q. Was it July of 2003? I read through the testimony last night, and there were a series of meetings in 2002 that extended, and there was at least one or two in 2003 that resulted I think in the Revised Protocol.

A. I'm not aware of when the Idaho or when the Washington Staff stopped participating. I don't have a recollection of that particular date, I'm sorry.

Q. Describe for me in brief how the MSP standing committee would work in dealing with a substantial change to let's say a cost allocation method.

A. Okay.

Q. How would it be brought up, how would it be resolved, and how would this neutral and how would each member of the committee participate in that?

A. The standing committee is put in place for the exact purpose of issues related to the Revised Protocol to be resolved or at least discussed and alternatives determined. If a state commission, the staff from a state or any other party from a state had concerns where they felt that the model no longer was producing reasonable results, then they can take a proposal before the standing committee to say we think such and such a change should be made to the Revised Protocol.

The standing committee then can assign members of the standing committee to review the issue, they can assign the company to go out and do additional analysis on that particular issue, or they can direct us to hire an independent third party to come in and do analysis on that particular issue viewing the merits of the change, the impact of the change across the different states, and make a proposal back to the standing committee as to whether they think the proposed change ought to be implemented, or it should be rejected, or perhaps some modification ought to be adopted.

The standing committee would then make a decision as to whether they want to propose that going forward. Once that decision has been made, then obviously it needs to go back in front of the individual state commissions to be adopted as part of the allocation methodology to be used in that state.

Q. Who would select the neutral, the standing neutral?

A. The appointed members of the standing committee have selected the standing neutral.

COMMISSIONER JONES: I see.

That's all I have, thank you.

JUDGE RENDAHL: I just have one follow-up question on that.

E X A M I N A T I O N

BY JUDGE RENDAHL:

Q. The standing committee is composed of the states that have already approved the Revised Protocol; is that correct?

A. That's correct.

Q. So Washington would not be included on that committee until it approves the Revised Protocol; is that correct?

A. That's correct. Once they have ratified and adopted the Revised Protocol, they're encouraged and welcome to become a member of that committee.

Q. Is there any way at this point for Washington to participate in the standing committee without being a member?

A. I certainly don't think they would be excluded from observing the meetings, but they would not have standing as a part of the committee itself until

Washington had adopted the Revised Protocol.

JUDGE RENDAHL: Okay, I have nothing further.

With that, we've gone a little over past noon, we will take our lunch break now.

Mr. Taylor, you may step down, you're excused, thank you very much.

We'll be off the record and reconvene at 1:30.

(Luncheon recess taken at 12:10 p.m.)

A F T E R N O O N   S E S S I O N

(1:30 p.m.)

JUDGE RENDAHL: We're back on the record after our lunch break in the PacifiCorp rate case docket, and we're now going to turn to hearing cross-examination of Mr. Widmer.

Mr. Widmer, would you raise your right hand, please.

(Witness MARK T. WIDMER was sworn.)

JUDGE RENDAHL: Please be seated.

Go ahead, Mr. Galloway.

MR. GALLOWAY: Good afternoon, Your Honor.

Whereupon,

MARK T. WIDMER,

having been first duly sworn, was called as a witness herein and was examined and testified as follows:

D I R E C T   E X A M I N A T I O N

BY MR. GALLOWAY:

Q. Good afternoon, Mr. Widmer.

A. Good afternoon.

Q. Please state your full name.

A. My name is Mark Thomas Widmer.

Q. And how are you employed with PacifiCorp?

A. I'm a Director of the Net Power Cost Group.

Q. Has direct testimony been filed on your behalf which has been previously marked as Exhibit 391-T?

A. Yes, it has.

Q. And are Exhibits 392 through 397 appended to that testimony?

A. Yes, they are.

Q. And have you also filed rebuttal testimony that has been previously marked as 398-T?

A. I did.

Q. And does that support Exhibits 399 through 401?

A. Through 400, Cross-exam Exhibit 401 is not part of my rebuttal testimony.

JUDGE RENDAHL: Actually, as a clarification, it's the stipulation on power cost issues.

THE WITNESS: I understand what it is.

JUDGE RENDAHL: And I realize it wasn't filed as a part of your exhibits, but I included it because you appeared to be the witness who was sponsoring it for the company.

THE WITNESS: Yes.

BY MR. GALLOWAY:

Q. With that clarification, you're sponsoring 401, are you not?

A. Yes, I am.

Q. Mr. Widmer, if I were to ask you the questions that are set forth in Exhibit 391-T, would your answers as set forth therein be the same?

A. I have one correction.

Q. And what is that correction?

A. On line 4 of page 1, regulation should be struck, and that should be net power cost.

Q. And are there any corrections to your rebuttal testimony that you would like to make?

A. No, there are not.

Q. If I were to ask you the questions set forth in Exhibit 398-T, would your answers be the same as set forth therein?

A. Yes, they would.

Q. And are Exhibits 392 through 397 and Exhibits 399 through 401 true and correct to the best of your knowledge?

A. Yes, they are.

MR. GALLOWAY: And we might as well take care of the Staff and Public Counsel and ICNU Exhibits, 402-C and 403 through 411, and the company has no objection to admission of those exhibits.

JUDGE RENDAHL: Thank you.

With that, is there any objection to admitting what's been marked as Exhibit 391-T through Exhibit 411?

Hearing no objection, those exhibits will be admitted.

MR. GALLOWAY: Mr. Widmer is available for cross-examination.

JUDGE RENDAHL: Thank you, Mr. Galloway.

Mr. Trotter.

MR. TROTTER: Thank you.

C R O S S - E X A M I N A T I O N

BY MR. TROTTER:

Q. Turn to page 2 of your rebuttal, starting on line 20 you address the hydro deferral issue.

JUDGE MACE: Mr. Trotter, would you please repeat that reference.

Q. Exhibit 398-T, page 2, line 20, and you state that Mr. Buckley recommends a recovery of $2.1 Million of the hydro deferral that the company had calculated; is that right?

A. That's correct.

Q. And you initially had a $6.1 Million calculation, has that been updated?

A. Yes, it was updated in my rebuttal testimony through Exhibit Number 9, and that amount is now $8.3 Million.

MR. GALLOWAY: Mr. Widmer, I think for clarity if you could, do you have the Commission numbered exhibits before you?

THE WITNESS: I do.

MR. GALLOWAY: So when you said Exhibit 9, it would be 399?

THE WITNESS: That's correct.

MR. GALLOWAY: Okay.

BY MR. TROTTER:

Q. And did you do an errata to your page 3, or should we change the 6.1 to 8.3?

A. We should change that.

MR. TROTTER: Could the record reflect that, Your Honor.

JUDGE RENDAHL: So line 1 where it reads $6.1 Million should be $8.3 Million; is that correct?

MR. TROTTER: Yes.

JUDGE RENDAHL: Okay.

BY MR. TROTTER:

Q. And is it your testimony that you are recommending the Commission reject Staff's proposed company recovery of $2.1 Million and recommend instead that the company recover $8.3 Million in excess costs as calculated by the company's methodology?

A. Yes, that's the company's recommendation.

Q. If the Commission chooses to reject both the company and Staff's proposal, the company would receive no additional moneys associated with these deferred dollars; is that right?

A. That would be up to the Commission.

Q. If actual hydro generation for the period beginning January 2006 is higher than normalized amounts and that condition continues until such time as a power cost adjustment mechanism may be initiated, would it be reasonable to expect that the deferral amount might decrease?

A. It could.

Q. Now under Mr. Buckley's proposal of a one-time allowance or recovery of $2.1 Million, that amount would not be reduced, would it?

A. As I read Mr. Buckley's proposal, I don't think it would be reduced.

Q. I would refer you to Exhibit 402-C, I'm not going to ask you any questions about the confidential material at the end. Among other things, this data request from Staff asked the company to show the changes in fuel prices and market prices used to determine net power costs in this filing compared to the last general rate case and to provide fuel prices associated with the Hermiston facility for the years 2000 through 2010; is that right?

A. That's correct. However, one thing I would like to point out on the exhibit, and that is the gas prices which are shown on the exhibit marked WTC-108 A-2 do not include the $33 Million of benefits derived from the company's natural gas resale. If those resales are included in the price of natural gas, the average natural gas price drops from $5.44 per MMBtu to $4.35 per MMBtu.

Q. Okay, well, let's, I'm not sure that's a point we're focusing on, but let's go to, I apologize to the Commission, these pages are not numbered, but the first page after the data request is Attachment 108 A-1; is that right?

A. Yes.

Q. Okay, let's skip over that to attachment 108 A-2.

JUDGE RENDAHL: And if you look in the lower right-hand corner, are you talking about page 7?

MR. TROTTER: Well, for some reason, Your Honor, the exhibit I'm looking at does not have page numbers at the bottom, so I think you're right.

JUDGE RENDAHL: It says July 7, 2005, page 1 of 1?

MR. TROTTER: Yes.

JUDGE RENDAHL: Okay.

BY MR. TROTTER:

Q. And here you show three series of data involving the first part is 2004 fuel prices, the second is 2007, and the third is the difference; is that right?

A. Yes, subject to the change that I made earlier.

Q. That's fine. And so if we wanted to focus on natural gas prices, we would take a look at the figures

for Gadsby, Little Mountain, and West Valley, correct?
A. You can also look at Hermiston.
Q. Okay, and that's on the following pages, right?
A. Mm-hm.
Q. Okay. Well, on this page let's focus on Gadsby and West Valley, and for 2007 the prices are considerably higher than 2004; is that right?
A. Yes, the average gas price is 13% higher than the 2004 price.
Q. Is the gas that's purchased for those projects done at market?
A. Well, when the gas is purchased, it's purchased at market, but the company employs a hedge strategy where we buy gas up to 48 months forward. So in this instance, by the time we got to or will get to the test period, these costs will be quite a bit below market.
Q. Okay, turn forward 2 pages, oh, where you show average delivered cost to Hermiston January 2000 through March 2005.
A. Yes.
Q. And Hermiston is a gas powered plant located in the Western Control Area; is that right?
A. Yes, it is.

Q. And the gas prices for that facility seem to be more stable than the prices that we just talked about; is there a reason for that?

A. Yes, the fueling for the Hermiston plant is under a long-term contract. That contract escalates at 5 1/2% per year.

Q. And so if we turn over 2 more pages, the response to 108 B-2 shows the gas price at Hermiston from January '05 through December 2010?

A. Yes.

Q. And that reflects the 5% feature you just discussed?

A. Yes, it does.

Q. The same sort of contract does not apply for the West Valley and Gadsby plants; is that right?

A. They do not.

Q. What about Currant Creek, which is not shown here because it's not in service, but the same as Gadsby?

A. Yes, we buy from the market on a hedge basis.

MR. TROTTER: Those are all my questions, Your Honor, thank you.

JUDGE RENDAHL: Mr. ffitch.

C R O S S - E X A M I N A T I O N

BY MR. FFITCH:

Q. Good afternoon, Mr. Widmer.

A. Good afternoon.

Q. I have a few questions that are on topics that were deferred to you by Ms. Omohundro, and I'm not sure if she warned you about these or not, but I will go ahead and take her invitation. These questions relate to the structure of the PCA proposal from the company. First of all, Mr. Widmer, under the PacifiCorp PCA proposal, new contracts are fully included while new rebuilts or purchased rate base additions would not be fully rolled into the PCA; is that a correct statement?

A. That's correct.

Q. Another topic deferred to you, subsequent to the merger with Utah Power, did PacifiCorp experience a period of time where the company experienced declining power costs?

A. Well, over the ensuing ten year period from the Utah Power merger, prices vacillated up and down a little bit but generally were flat over that entire ten year period, and it wasn't until calendar year 2000 that we really saw a run up in market prices, which at that time was tied directly to the energy crisis and some other things that were going on on the company system.

Q. All right.
Back to the PCA proposal, the PCA proposal includes a retail revenue credit proposal similar to Avista, correct?
A. Yes, it does.
Q. Are the transmission, excuse me, are transmission revenues included in your proposal?
A. We do not -- we took a look at transmission revenues and decided that since they're not included in our variable net power costs that we would not include them. We just included the items that were included within our variable net power costs.
Q. Does the retail revenue credit include this system transmission plant and associated operations and maintenance or O&M?
A. No, it only includes the generation portion.
Q. Are you aware that in Puget's PCA, all of these costs are included as either variable or fixed items?
A. Yes, the Puget PCA is different than the Avista mechanism in that regard.
Q. And in the Avista mechanism, the ERM, no transmission or wheeling items are included, correct?
A. That's correct.
MR. FFITCH: Thank you, Mr. Widmer.

Your Honor, those are all my questions.

JUDGE RENDAHL: Okay.

Mr. Sanger.

MR. SANGER: Thank you.

C R O S S - E X A M I N A T I O N

BY MR. SANGER:

Q. Afternoon, Mr. Widmer.

A. Good afternoon.

Q. I'm going to ask some follow-up questions that Mr. Trotter started regarding the hydro deferral.

A. Mm-hm.

Q. When did PacifiCorp file the hydro deferral in Washington?

A. March 17th, 2005.

Q. What is the time period that PacifiCorp is requesting to defer its hydro costs?

A. We requested that the hydro deferral be in place until a more comprehensive PCA mechanism could be put in place.

Q. And is PacifiCorp requesting to amortize its deferred power costs in this proceeding?

A. That's probably a question for Mr. Wrigley, but I believe the answer is that we were agreeable to Staff's proposed amortization period.

Q. So the company is not proposing its own amortization of its deferred power costs in this proceeding?

A. Well, I don't -- I'm not sure I guess.

Q. Okay.

Did PacifiCorp submit any direct testimony in this proceeding that establishes the prudence of its deferred power costs?

A. We did not file any testimony. I assume that under similar type mechanisms or PCA's, typically utilities make filings demonstrating the prudence and appropriateness of the cost deferred before they're allowed to collect those costs, and we're not at the end of the deferral period yet, so.

Q. Do you think it would be appropriate for the company to file direct testimony regarding the prudence of those costs before they were amortized in rates?

A. I don't know that filing direct testimony is necessary. If you look at like the PSE PCA mechanism, I don't believe they're required to file testimony in that regard regarding recovery of costs deferred under that mechanism, but they file work papers and other documents to support getting recovery of their costs deferred.

Q. Are you familiar with the PacifiCorp filing of a power cost deferral case in Docket UE-020417? That was the power cost deferral the company filed back in 2002.

A. I'm not very familiar with that.

Q. Did you file direct testimony in that proceeding?

A. I did, but I didn't file testimony on the proposed mechanism.

Q. What did your testimony address?

A. My testimony addressed primarily the recovery of excess power costs, if memory serves me correct.

Q. And did you file testimony regarding the prudence of those excess net power costs?

A. Yes, we did.

MR. SANGER: I have no further questions, Your Honor.

JUDGE RENDAHL: All right, is there any redirect for the witness?

MR. GALLOWAY: There is not, Your Honor.

JUDGE RENDAHL: Okay, are there any questions from the Bench for this witness?

Commissioner Oshie.

E X A M I N A T I O N

BY COMMISSIONER OSHIE:

Q. Mr. Widmer, I just have a -- I wanted to question you about your conclusions in your testimony that the power costs for PacifiCorp have increased by I think you used the percentage 3100% over the period 1999 to 2004. And looking through your testimony, it takes me to Exhibit 394, which I assume supports your conclusion from your direct testimony?

A. Yes, it does.

Q. And can you tell me why your exhibit contains both Oregon rates and/or the Oregon I guess I will call it base line rates up to 2000 and then Washington base line rates from 2001 to 2004?

A. Yes, I can. We included Oregon information from 1990 through 1999 because we didn't have any rate activity in the state of Washington during that period in part because excess power costs weren't a recovery issue. We were recovering substantially all of our costs. I believe over that ten year period our net recovery or disallowance was $10 Million. But we did have cases in Oregon, and Oregon is, you know, finds results on a total company basis for power costs, so we thought that that would be a reasonable proxy given the fact that we didn't have any regulatory activity in Washington.

Q. Would it be possible for you to produce an exhibit that just includes Washington rates?

A. Yes, or we could just look at the information from 2000 forward.

Q. If we just looked at the information from 2000 forward, does that support your 3100 figure?

A. Well, it wouldn't support the 3100 figure in terms of the growth in our recovery risk, because we wouldn't have a base line to measure that against. But nonetheless it still provides substantial support for the fact that the company's recovery risk is very asymmetric, meaning the company has not recovered the expected value of its net power cost. And to define that a little further, that means under normalized regulation the theory is that over the long run the cost increases and decreases will balance out and everybody will be appropriately compensated.

Q. Now I was --

A. That's not happening here.

Q. I'm assuming that your exhibit does not net out any moneys that have been allowed by commissions for the company to recover its power cost from say the energy crisis, 2001 to 2002?

A. No, the whole purpose of this exhibit is to look at Washington only numbers to show what the results would have been if we were only looking at Washington, and Washington didn't provide any recovery of these costs.

Q. If we eliminated the energy crisis years, 2000, 2001, 2002, would your volatility, would you expect your volatility measure to stay at 3100 times, or would you think that it would go higher or be reduced?

A. It would be reduced, but it would still be very substantial. Because during the energy crisis, the manipulation in market prices wasn't the only thing going on. If you recall, the region experienced a second worst water year on record during that time frame. As a result of that, the company lost over 2 million megawatt hours of generation.

Q. Are you talking about the Hunter plant forced outage?

A. No, I'm talking about hydro conditions.

Q. You're talking only about hydro conditions?

A. Yeah. In addition to that, we lost about 1 1/2 million megawatt hours because of the outage at the Hunter Wyodak facility. So if you peeled off, if you could, the impact of the market manipulation, our excess power costs would have still been very substantial.

Q. And your figures include then the Hunter forced outage costs to the company?

A. They're all included.

Q. And Hayden, the Hayden forced outage cost, was there forced outage there?

A. There's forced outages at all of our facilities.

Q. I thought there was one that occurred in that same period as the Hunter facility that was somewhere down around, you know, that was about 1800 total hours as a forced outage.

A. There may have been, I don't recall.

Q. Okay.

Do you consider the Western Power Crisis, the lowest water year on record, the forced outage at Hunter, to be an extraordinary event or events that are in the normal course of business for the utility?

A. Well, I think if you look at the energy crisis, you know, it's kind of like the perfect storm. We had a lot of things that all occurred at once, and so from that perspective I would say it was very extraordinary. However, we do have major plant outages from time to time, it's part of the business. You know, thermal plants are run under extreme pressures, and the one thing we know is they're going to break, we just don't know when they're going to break and how extensive the break is going to be, so that's pretty normal to see facilities break.

Q. In the Hunter forced outage, did you recover

those costs from all of your jurisdictions, or perhaps maybe as a foundation question, did you request recovery for the Hunter forced outage from the other jurisdictions of which the company is providing service?
A. We did.
Q. And did you recover from each jurisdiction the amount of dollars requested?
A. We recovered a subset of the dollars requested that ranged from somewhere in the low 50% range up to almost 70%.
Q. Did all jurisdictions allow recovery?
A. All except Wyoming.
Q. All but Wyoming?
A. Mm-hm.
Q. Do you think a power cost adjustment mechanism should be designed to capture normal variation in power costs or to reflect extraordinary variations in power costs?
A. I think a power cost adjustment mechanism should be designed so that a utility is recovering its expected value and so that our recovery complies with the theory of normalization whereby over the long run the cost increases and decreases will balance out.
Q. Would you, it seems to me having sat on the Bench for both the Puget and the Avista power cost

adjustment mechanisms that both were allowed by the Commission following a request by the company after the energy crisis in which extraordinary losses were absorbed by both companies.

A. Could you repeat the question?

Q. Well, maybe there's not a question in there yet, Mr. Widmer. But did you find that, you know, PacifiCorp's circumstances are similar then in nature to those that were confronted by both Puget and by Avista when the Commission allowed their power cost adjustment mechanisms to be authorized?

A. I think they were similar along the lines of the fact that the company incurred significant losses, yes.

Q. Does the time differential make any difference here perhaps?

A. The timing of when the --

Q. The timing of when the request is made.

A. Well, we actually requested deferral of excess power costs in most of our jurisdictions during the middle of the energy crisis. We didn't wait until it was over.

Q. How is that reflected in this filing?

A. It's not at all.

Q. Well, let me go back to my question. Do you

think the power cost adjustment mechanism should be designed to protect the company from normal variations in power costs or extraordinary variations in power costs?
A. In general I would -- it's a two-part answer. In general I think should be normally set up to protect the company from unusual events. However, because the company's net power cost recovery is asymmetric, I mean we're not recovering our prudently incurred costs in the state of Washington, we have proposed a PCA mechanism that would bring us back closer to the point whereby we would be closer to recovering our expected value over the long run and then have a fair opportunity to earn our authorized rate of return.
Q. Your testimony regarding the increased net power cost to the company, how much has the increase in customer loads affected your total number?
A. I haven't done that calculation, I couldn't tell you. I can tell you what we included in the case, the impact on loads, if that would be useful.
Q. Well, I think what I'm driving at here and would like, I think you answered my question, is whether the difference between the company, your representation that there is an asymmetrical risk that the company absorbs as a result of its underrecovery of power cost

which is set by the difference between what the cost that it incurs and the average base line, how much are the costs that you have in, as built in to your Exhibit 394, reflect an increase in load, not necessarily the results from let's say extraordinary occurrences in the natural gas market as an example?

A. A portion of it would be related to load growth, and a portion of it is related to volatility that the company can't control relative to natural gas and other events.

Q. Could you produce for the Commission, actually redo your Exhibit 394 to remove the effects of the Western Power Crisis from your numbers, so maybe you would have to normalize what you believe those, your power costs would have been absent the extraordinary circumstances of those years and the lowest water year on record as I believe you testified to?

A. We could make an attempt to do that; however, I just want you to be aware that it would be very subjective to look at the factors that were going on during the energy crisis and be able to differentiate how much of that was related to market manipulation, how much it was related to the poor water conditions, how much of it was related to, you know, the Hunter 1 outage and other outages within a region, it would be very hard to delineate that, but we could take a shot at it if you would like.

Q. Well, perhaps you can adjust for at least my benefit, if not the whole Commission, remove those extraordinary events, and then we will see I guess where your risk factor analysis comes at that point, whether it's 3100, which I don't think it would be at that point.

A. It would be lower.

JUDGE RENDAHL: So that would be Bench Request 21.

Q. One last question, I think you testified to the 90/10 risk sharing in the power cost adjustment mechanism; is that true?

A. Yes, I did.

Q. And I think that if I remember right from your testimony you stated that 90/10 was appropriate because you would be -- you didn't have an annual true up of those power costs as you may have in other jurisdictions?

A. Yeah, we drew a comparison to the situation that we have in Oregon. In Oregon we have a annual mechanism, it's called a transition adjustment mechanism or TAM, and that mechanism allows the company to update its net power costs annually on a forecast basis.

Effectively what that mechanism does, it eliminates all the company's regulatory lag in terms of power costs, because rates go into effect at the start of the forecast period. Given that we have that mechanism in Oregon, we proposed a different PCA mechanism in Oregon. We proposed a mechanism that still did not have a deadband, but we proposed a higher sharing level whereby 70% of cost increases and decreases would be assigned to customers, and 30% of the cost increases and decreases would be born by the company.

Q. You know, when I read your testimony and reflected back on earlier testimony in this proceeding that the company was coming in in June with a new general rate case, I thought, well, why wouldn't you propose at least in this jurisdiction for the period in question in this matter a 70/30 split, because you will be back in almost -- in a very short time with the opportunity to readjust your base power rates at that point much like you were getting in Oregon or proposed in Oregon?

A. Could you repeat that, I didn't follow all that.

Q. Well, in Oregon you get to true up your power costs annually, therefore removing the regulatory lag I think as you testified, and as a result the company isn't -- is willing to share the risks more generously with the rate payers and will split those risks 70% to the company, 30% to the rate payers, or excuse me, the other way around, 70 rate payers, 30 the company. And in this matter you proposed a 90/10 split, but you will be coming back in in June with an opportunity to reset your base line power costs at that point, so when I read that, and given the principles employed I thought in your reasoning why, it struck me that I was surprised you didn't come in and ask us, the company come in and ask us for a 70/30 split given the fact you're going to be right back in here in a very near time to adjust the rates and adjust the power costs.

A. Well --

Q. An opportunity to do that as well.

A. Well, the issue in Washington is that rates are set on a historical basis, so there's a tremendous amount of regulatory lag. In Oregon rates are set on a forecast basis, so we don't have that extent of lag. And as a result, the risk, recovery risk for us in the state of Washington is much greater than it is in the state of Oregon.

Q. Well, your power costs here, don't they go out to 2007 in this case?

A. Power costs here go out through the rate effective period, which is March 2007, but they're discounted back pursuant to the prediction factor methodology to the historical test period.

COMMISSIONER OSHIE: I don't have any further questions, thank you, Mr. Widmer.

THE WITNESS: Thank you.

JUDGE RENDAHL: Commissioner Jones.

E X A M I N A T I O N

BY COMMISSIONER JONES:

Q. I just have kind of a brief question on the model, the modeling of average market prices and how grid is it release 5.1, the current release?

A. Yes, it is.

Q. And I read your testimony on the differences between the previous release and this release. Is there any difference in the way that it handles the forecasted average market prices out through 2008?

A. No.

Q. Are you familiar with the Aurora model?

A. We as a company looked at it many, many years ago and didn't find it to be a satisfactory model at that time.

Q. Are you aware that Avista uses the Aurora model?

A. I believe both Avista and Puget do.

Q. Have you had a chance since you are modeling, is it correct that you are modeling your PCAM power cost adjustment on the ERM of Avista?

A. That's what we based our, for the most part, our request on.

Q. I'm looking at Exhibit 396 in your direct testimony, if you want to turn to that if you would, the forecast average market prices for COB, Mid-Columbia, and Palo Verde out through, what is that, the end of 2008, what's the time period covered here?

A. I believe it's the end of 2008.

Q. Okay. My question is, does this forecast of average market prices, does that conform to the way in which Aurora handles the forecast of average market prices, or do you know?

A. I believe this is different. Our forecast of market price is based on in the near term short run for five to six years. It's based on broker quotes from independent third parties. It's my understanding that the Aurora model takes a fundamental approach to determining market prices and it looks at what units are on the margin across the system, dispatches a system, and develops market prices that way, so they're different in that regard.

COMMISSIONER JONES: I see. That's all I have, thank you.

E X A M I N A T I O N

BY CHAIRMAN SIDRAN:

Q. Mr. Widmer, it would be helpful to try to compare these various power cost adjustment mechanisms in two respects, and so I guess I will characterize this as a Bench request, because it didn't -- I didn't see it at least in a way that I could easily grasp set forth in the exhibits. One is to compare and contrast what you're proposing in this regard in Washington state with that being proposed in all of your other jurisdictions so that we can see a head-to-head. And if you want to explain as you did in response to Commissioner Oshie's question why it's different in Oregon for example than what's being proposed here, that's fine. But it would be helpful to simply have a head-to-head comparison with each jurisdiction, what you're proposing, the similarities and differences, and when they differ why they differ.

And the second is to just do that within Washington state. Presumably we will begin by, as you did, asking, well, what is similar or different between your company and Avista or your company and Puget Sound

Energy, so it would be useful to have a head-to-head comparison of your proposal versus the existing mechanisms for PSE and for Avista and why you think your company is either similarly situated or different from those other companies. And perhaps Judge Rendahl can help me with what number Bench request that is.

JUDGE RENDAHL: Well, I'm wondering if you would like to do two, one would be the comparison with the other states.

CHAIRMAN SIDRAN: That's fine.

JUDGE RENDAHL: So that would be 22. And then 23 would be a comparison with PSE and Avista.

CHAIRMAN SIDRAN: All right, that's fine.

BY CHAIRMAN SIDRAN:

Q. And I just have a couple of technical questions about the mechanics as I understand it of the current proposal from PacifiCorp, and that is how the -- once the $5 Million trigger is reached on the deferral account, does that happen only once a year?

A. That could happen --

Q. Or does it roll forward?

A. Well, it could happen several times during a year depending upon the level of volatility. The idea behind the trigger is that once the deferred balance reaches that level, then the company has the right to come in and seek recovery of those costs. So during a period of high volatility, we might be in more often during a year. During a period of low volatility, because it's a trigger not defined by a length of time, we may not be in for a couple years, two years, something like that. It just depends on the level of volatility.

Q. So you might come in more often than once a year, whenever you reach the $5 Million mark?

A. Could be more, could be less.

CHAIRMAN SIDRAN: Thank you, that's all.

E X A M I N A T I O N

BY JUDGE RENDAHL:

Q. Okay, just to follow up on the Chair's question, so the company would continue adding amounts monthly, so you reach the $5 Million trigger amount for example maybe in September of this year, but in October while you're making these, you're paying out the surcharge, you're applying the surcharge to the customer's bill or applying a credit, you would also figure out what's happening in October, and then the end of October you would add that to the same deferral account, or are you going to track separately? I'm a bit confused on the accounting, although not being an accountant I'm not sure I will understand extreme detail, but it would be helpful to get a general sense of how this works.

A. I'm not an accountant either, but basically the way it would work is once the deferral balance received that amount, we would remove it from the deferral account, put it in a separate account, and request recovery of that so that the amortization of the amount requested could be tracked. In the meantime, you know, more months go by, and we are still calculating our deferrals, you know, whether we're collecting too much or not collecting enough.

Q. So you would remove the $5 Million reducing the account to zero, put it in another account for either surcharges or credits?

A. Yes.

Q. Now is that for a one year period that you would apply the surcharges and credits?

A. That's our recommendation.

Q. And then at the end of that one year period, if there is anything left over, you would put it back into the account?

A. We would figure out something to do with it, yeah.

Q. Okay. If you look at your testimony, your direct testimony, 391-T, on page 36, in talking about your earnings demonstration proposal, it's the last page of your testimony, on line 9 you use a term called deferral period, what do you mean by deferral period?

A. What we're talking about there is the period of time that eclipsed leading up to the $5 Million being deferred.

Q. All right, and one last question, are you aware that Mr. Hadaway selected for his cost of capital analysis comparable companies that have an approved PCA mechanism?

A. I am.

Q. And did you work with or assist Mr. Hadaway in identifying or selecting those comparable companies?

A. I did not.

JUDGE RENDAHL: Okay, I have no other questions.

Are there any other questions from the Bench?

All right, with that, thank you very much, Mr. Widmer, you may step down.

THE WITNESS: Thank you.

JUDGE RENDAHL: We will take a brief recess and begin with Mr. Tallman. Let's be off the record.

(Recess taken.)

JUDGE RENDAHL: Let's be back on the record after our brief break, and we will begin with Mr. Tallman.

Mr. Tallman, are you ready?

(Witness MARK R. TALLMAN was sworn.)

JUDGE RENDAHL: Please go ahead, Mr. Galloway.

MR. GALLOWAY: Thank you, Your Honor.

Whereupon,

MARK R. TALLMAN,

having been first duly sworn, was called as a witness herein and was examined and testified as follows:

D I R E C T   E X A M I N A T I O N

BY MR. GALLOWAY:

Q. Please state your full name, Mr. Tallman.

A. Mark R. Tallman.

Q. How are you employed by PacifiCorp?

A. I am currently the Managing Director of our Trading and Origination Activities in our front office in the regulated merchant function.

Q. You prefiled direct testimony that has been previously marked as Exhibit 421-T?

A. Yes.

Q. And are Exhibits 422 through 439 accompanying that direct testimony?

A. Yes.

Q. And have you also filed prefiled rebuttal testimony that's been previously marked as Exhibit 440-T?

A. Yes.

Q. And it is accompanied by Exhibit 441?

A. Correct.

Q. Are there any changes you would like to make at this time to your direct or rebuttal testimony?

A. I have one small change to the rebuttal. It's on page 3, line 17, 2003-B should read 2003-A. Those are the only changes.

JUDGE RENDAHL: And that's on line 17?

THE WITNESS: Correct.

BY MR. GALLOWAY:

Q. And with that change, if I were to ask you the questions set forth in Exhibit 421-T, would your answers set forth therein be the same?

A. Yes.

Q. And similarly if I were to ask you the questions set forth in Exhibit 440-T, would your answers be the same?

A. Yes.

Q. And are Exhibits 422 through 439-C and

Exhibit 441 true and correct to the best of your knowledge?

A. Yes.

MR. GALLOWAY: Your Honor, at this time I would like to offer Exhibits 421-T through 441.

JUDGE RENDAHL: Are there any objections to admitting what's been marked as Exhibit 421-T through Exhibit 441?

Hearing nothing, those exhibits will be admitted.

And, Mr. Galloway, can you speak more directly into your microphone.

MR. GALLOWAY: I'm sorry.

JUDGE RENDAHL: Mostly for the benefit of those on the bridge.

MR. GALLOWAY: And, Your Honor, at this time I would state that the company does not have objection to the cross-examination Exhibits 442 through 452 that have been proffered by Public Counsel.

JUDGE RENDAHL: All right, with that, any objections to admitting what's been marked as Exhibits 442 through 452?

Hearing nothing, those exhibits will be admitted.

MR. GALLOWAY: Mr. Tallman is available for cross-examination.

JUDGE RENDAHL: Mr. Trotter.

MR. TROTTER: Thank you, Your Honor.

C R O S S - E X A M I N A T I O N

BY MR. TROTTER:

Q. Mr. Tallman, a couple of questions were deferred to you from Mr. Duvall, so I'm going to just ask you those questions. The first is, in the RFP process, the company identified the specific parameters for needed resources including delivery points; is that correct?

A. Well, the company implemented the IRP in formulating its RFP, so.

JUDGE RENDAHL: Mr. Tallman, can you push the button up. Up is on. It's kind of not intuitive.

THE WITNESS: Sorry, I assumed I was there up until now.

JUDGE RENDAHL: Go ahead.

A. In formulating our request for proposals, the company is essentially typically implementing integrated resource plan action items. So in terms of determining where on the system that we're looking to acquire resources, we look to the integrated resource plan to help guide us. And so therefore that's generally what guides us in crafting the minimum parameters of the request for proposals.

BY MR. TROTTER:

Q. And RFP's do include delivery points for power, do they not?

A. They include minimum criteria for delivery points, yes.

Q. In Utah the company identifies what resources it needs, where they're needed, and why they are needed when it files for certificates of necessity to construct a project in that state; is that correct?

A. Well, in Utah the certification process is primarily by need, so it's purely a construct of if an asset is going to be located in Utah, then you're required to go through a certification process. That's going to be somewhat different going forward now because of a recent legislation passed, but historically for these resources that was the case.

Q. And does the company file truthful information in those dockets?

A. Yes.

Q. I would like to discuss with you Exhibit 432, which is entitled the Navigant, N-A-V-I-G-A-N-T, report; would you turn to that exhibit, please.

A. Yes, I need to get it off the desk.

Q. And just turn to, I'm referring to page numbers at the lower right corner, page 1.
A. Correct.
Q. And this is one of the consultant reports that Pacific Power, excuse me, PacifiCorp procured. This one was for an evaluation of the 2003-A RFP; is that right?
A. That's correct.
Q. Turn to page 10 under the section entitled rationale behind the RFP. The last sentence states in part:

> In initiating this process, the company has remained focused on achieving three key outcomes. Number one, a clear plan that satisfies the needs and objectives of each state.

Do you see that?
A. Yes.
Q. And do you believe that that is a need and objective of the company for all of its RFP's?
A. Correct, it's a reference back to the integrated resource plan.
Q. So it's also a needed objective of the IRP as well?
A. Correct.

Q. Turn to page 13, the first paragraph, second sentence states that:

The first IRP was intended to meet the company's growing resource need in the Eastern portion of its system.

Do you see that?

A. Yes, I do.

Q. And by Eastern portion, is that referring to the Eastern Control Area?

A. Generally, yes.

Q. I talked to you a minute or so ago about points of delivery, would you turn to page 32 of the Exhibit. Table D is a description of PacifiCorp's bid categories, do you see that table?

A. Correct.

Q. And the point of delivery for both baseload, peaker, and super peak resources that were being bid was the same, and that is "in or to PacifiCorp Eastern System (PACE)".

A. Correct, that's the minimum criteria.

Q. And is that again a reference to the Eastern Control Area?

A. In this case, yes.

MR. TROTTER: I believe that's all I have, Your Honor, thank you.

JUDGE RENDAHL: Thank you.
Mr. ffitch.
MR. FFITCH: Thank you, Your Honor.

C R O S S - E X A M I N A T I O N

BY MR. FFITCH:

Q. Good afternoon, Mr. Tallman.

A. Good afternoon.

Q. In your filed testimony in this case, was it your intention to satisfy PacifiCorp's burden to demonstrate prudence for the new long-term electric resources that the company has acquired?

A. Yes, that was the intent.

Q. And do you believe that the new resources that PacifiCorp has acquired and that are located in the Eastern Control Area are used and useful to serve PacifiCorp's retail electric customers in the Western Control Area including Washington state?

A. I believe they're used and useful and Washington customers benefit from them because they're useful to the system.

Q. Are they used and useful to serve retail electric customers in Washington state?

A. We don't track our electrons and where they flow.

Q. Are you familiar with the processes and analysis that PacifiCorp used to develop its 2003 and 2004 integrated resource plans?

A. Yes, generally.

Q. Would you agree that those two integrated resource plans used the following as primary measures to evaluate and select long-term resource acquisition strategy, and I will list the three items, portfolio cost, portfolio risk, and portfolio environmental impacts?

A. I think I can agree with that subject to check. I would have to go back and reread the IRP's.

Q. All right. Did PacifiCorp use these same measures in the processes it used to evaluate and select the new long-term resources it has acquired?

A. Well, again going back to the question Mr. Trotter, answer to Mr. Trotter's question, we look to the IRP for guidance in formulating our RFP's. So the IRP looks at the best overall set of solutions for the system, and then my organization sets about to implement the action items in the IRP.

Q. But did the company use the same measures, the portfolio cost, portfolio risk, and portfolio environmental impacts, to evaluate and select specific resources that it acquired?

A. That had already taken place in the IRP, so the purpose of the RFP is to find the best alternatives that are reasonably available to the company.

Q. Did the evaluations used to acquire those resources emphasize how the resource acquisition candidates would affect cost, risk, and environmental impacts for the overall portfolio, or were different measures used to evaluate the candidates on more of a stand-alone basis?

A. It was a stand-alone analysis, and yes, they did take into account those characteristics consistent with the integrated resource plan.

Q. Are you familiar with the term mark to market?

A. I am.

Q. Did PacifiCorp perform mark to market calculations and use those results as a key part of its process to evaluate and select new electric resources?

A. We did an analysis that compared the cost effectiveness of the resource that we were looking at against a market forward price curve, which is the same forward price curve we use for a number of other purposes within the company. So if that meets your definition of mark to market, then yes.

Q. Well, I was about to ask you that question.

You have started down that road a little bit, have you just sort of provided us a summary of the mark to market method or technique that was used by the company?

A. Well, mark to market can be a fairly broad term. It can mean a lot of things to a lot of people. In this instance, what we did is we compared each resource alternative against a forward price curve, determined whether or not we think the resource will be economic on that basis, which is very similar in concept to what the integrated resource plan does. It just simply, the integrated resource plan simply looks at a large number of resources taken together against a market forecast, whereas our RFP process took a look at individual offers that we had received.

Q. Was mark to market originally developed for use by regulated, vertically integrated utilities to evaluate new electric resources?

A. I couldn't tell you where -- who first invented the concept of comparing alternatives against market alternatives.

Q. Do you know what type of industry or in which type of industry it was first used?

A. I think all industries look at their available alternatives and compare them against their next best available alternatives, and that's simply in this case what mark to market conceptually is.

Q. Do you know if this Commission has previously approved the costs for any new long-term electric resource selected on the basis of mark to market in electric rates?

A. Well, I'm certainly not familiar with every prudence review that this Commission has undertaken, but if this Commission in the past has looked at projections for fuel, customer usage, generally market type factors, interest rate projections, then it has brought resources in on those bases, which conceptually is no different than what we're talking about here.

Q. I would like to give you a hypothetical or a couple of hypotheticals to work with here, so I will set these up carefully, and if you need me to repeat something, I will be happy to do that. Suppose that a candidate electric resource is being offered for sale in wholesale power supply for example delivered at a constant 100 megawatts per hour for 10 years at a fixed price of $50 per megawatt hour. Those are the basic parameters of the resource. Now suppose that the following entities use the mark to market method in order to evaluate the resource, two different entities. Entity A is a UTC regulated vertically integrated utility like PacifiCorp. Entity B is an unregulated wholesale energy trading and marketing company. And assume that both of these entities use the same forward price and the same discount rate. Do you have that hypothetical in mind?

A. What was the price you mentioned, was it $56?

Q. $50 per megawatt hour.

A. $50.

Q. So with that clarification, do you have the hypothetical in mind?

A. I think so.

Q. There's a lot of moving parts there perhaps.

Would you expect either the method or the results of the mark to market calculations by the two different entities to be significantly different?

A. Well, not knowing how other companies do their evaluations, assuming all things are equal, they should both see that transaction on similar economic footing.

Q. All right, let me change the -- well, let me go to another hypothetical.

Suppose that a vertically integrated utility has a need, now we're comparing two different vertically integrated utilities. Utility A has a need for a new baseload electric resource that's essentially constant throughout the day and throughout the year. Then utility B has a need for new peaking resources primarily during the daytime and the summer. Now as both utilities perform standard mark to market evaluations of resource acquisition candidates, they both use the same forward price, they both use the same discount rate, would the results of a mark to market calculation differ for the two utilities?

A. Assuming both products were made available to the utility, then they should be different.

Q. Would the results of the calculation indicate which resource would be more compatible with baseload resource needs or conversely with the seasonal peaking resource needs of the, you know, the first baseload needs of the utility A and the seasonal needs of utility B?

Do you follow the question?

A. No, I didn't, I'm sorry.

Q. I will repeat it.

Would the results of the mark to market calculations indicate which candidate resources are more compatible with the baseload resources of utility A or the seasonal peaking resources of utility B?

A. No, the mark to market would just simply be a calculation in that example.

Q. When a UTC regulated vertically integrated utility such as PacifiCorp evaluates new resource acquisition candidates, is it your professional opinion that each of the following measures is of equal usefulness and relevance, measure A, market value of candidate resources measured relative to wholesale power prices, measure B would be impacts of candidate resources on the net cost of the utility's overall portfolio of resources?

A. I would say A and B, A and/or B.

Q. The question is are they of equal usefulness and relevance?

A. In my opinion yes.

Q. Do the results of a mark to market calculation indicate the net impact of a resource candidate on the cost of a vertically integrated utility's portfolio?

A. It can, it can infer it.

Q. If a specific candidate resource, resource A, has the most favorable mark to market value compared to all other available resources, can you state with certainty that adding resource A to the utility's portfolio will produce the lowest expected cost for the portfolio?

A. I can't state with any more certainty than if I had used a production cost model, no.

Q. I'll move on to another area.

PacifiCorp also performed and used the results of options evaluations, or it does use the results of options evaluations as part of its evaluation and selection of electric resources; isn't that right?

A. In some cases, yes.

Q. And when that has occurred, are the options evaluations calculated in terms of PacifiCorp's overall resource portfolio, or are they calculated on a stand-alone basis?

A. It depends on the situation.

Q. And what would be the factors that would determine whether a portfolio approach was used versus a stand-alone?

A. Well, the factor would be whether or not you're even at the point of making the analysis. For example, if the integrated resource plan didn't indicate that we had a need for a on dated resource with embedded option, then we probably wouldn't be there doing the analysis in the first place.

Q. Well, I guess what I'm asking you is when you are making a resource acquisition because you have determined that you need a resource, that's a given here, and you stated that sometimes in that situation you have used an options evaluation.

A. Correct.

Q. So I have asked when that occurs, does PacifiCorp use a resource portfolio calculation or a stand-alone calculation, and I'm not sure I understand your answer.

A. It would be stand-alone in that instance. I'm not aware of a portfolio evaluation model that calculates option values.

Q. Would you agree that resources with greater operating flexibility and lower fixed costs such as peaking resources generally tend to have greater option value compared to baseload resources?

A. I can't say that in general, no, not without knowing the exact characteristics of the resource you're addressing.

Q. Suppose that a utility has a need for new resources to meet retail customer loads during peak periods and requires a new peaking resource to meet that need. If the utility must then hold the new peaking resource in readiness to meet peak loads and then it actually uses the resource to meet peak loads when they occur, how would it be possible for the utility to sell the option value of the peaking resource into the wholesale power market?

A. I guess I don't quite follow your line of questioning.

Q. Well, the basic premise is that we're talking about a utility that has a need for new resources to meet peaking loads for retail customers. It goes out and acquires that peaking resource. Based on that assumption, it's going to need to hold that resource to meet those peaks when they occur. And again based on that assumption, it's going to actually be using that resource to meet those peaks when they occur. Given all those underlying assumptions, my question is, how is it possible for the utility to then sell the option value of that resource into the wholesale power market?

A. When it's predicted that you won't be needing a resource, then you can go ahead and sell the energy that it could generate assuming it's economic against the market into the market. If I know I'm going to need a resource to serve load, then I know I'm going to need it, and when that load occurs it will be there. But there will be many other times when the resource isn't needed.

Q. But if you're correct in your forecasts, you know when you need it, you buy the resource that meets those needs, you're not going to have a resource available to option, are you?

A. During the other times when I don't need it I

will, yes.
Q. So you have purchased a resource that you don't need?
A. Every resource fits that category unless you can show me a resource that's available for a single hour only.
Q. If it's not possible for the utility to actually realize the option value of a peaking resource, which in your opinion is more important, the market value of the resource or the cost?
A. I don't agree with your fundamental premise. I do think it's possible to realize the value of all resources assuming that they're economic against the market.
Q. I understand that you differ with the underlying premise, but if you for purposes of argument accept the premise that the utility is not able to realize the option value, in that case which is more important, the market value or the cost?
A. Maybe I'm just not tracking with you. Is this a hypothetical question?
Q. This is a hypothetical.
A. This is a hypothetical. Well, it seems like a hypothetical that doesn't have a solution. If the underlying premise is that you can't realize the option

value, then the market value is irrelevant.

Q. All right, so that would mean that the cost would be the more important factor in that hypothetical?

A. It would still be a net cost scenario, in which case the market value is zero.

Q. In your rebuttal testimony on page 7, this is Exhibit 440-T, it's just a short -- I don't know that you're going to need to stay there long, but this is page 7 of 440, lines 3 to 4. Are you there?

A. It's page 7 of the rebuttal?

Q. Rebuttal, correct.

A. Sorry, I was looking at the other exhibit.

Q. Lines 3 to 4 you state:

PacifiCorp also has incorporated a risk assessment in each resource decision for the protection of retail customers.

Correct?

A. Correct.

Q. Were these risk assessments performed in terms of effects on the overall resource portfolio of the company?

A. No, it was with respect to each resource decision.

Q. Is it correct that PacifiCorp in deciding on resource acquisitions, individual resource acquisitions, looks at a range of factors including mark to market, option value, and risk analysis; is that essentially what you said in your testimony?

A. Correct.

Q. How are these three different factors combined? Is there a systematic process, or is it a matter of judgment that the company uses in determining which factor or how the factors interact or how they're weighted in that decision making process?

A. Well, our goal is to find the resources that have a prudent balance between cost and risk. Typically it gravitates toward a least cost standard, but there are times when risk is taken into account such as counterparty credit risk for example.

Q. So no systematic process per se that you use to blend these three factors that we have listed?

A. We have no preset criteria if that's what you're asking.

Q. If a consultant that PacifiCorp has hired states that the company has used a process and method to evaluate candidate resources that other utilities have used also, do you believe that this is in and of itself a significant demonstration of prudence for the new resources that PacifiCorp has acquired?

A. If it's a respected consultant, yes.

Q. Can you please turn to your rebuttal testimony, page 1; do you have that?

A. Yes.

Q. And lines 17 and 18, and there you state:

PacifiCorp's use of commodity valuation techniques are proper and, in fact, required under applicable accounting rules.

Are you referring there to FAS 133?

A. Correct.

Q. And that's been marked as an excerpt, an excerpt of that FAS 133 rule has been marked as Exhibit 442 as one of your cross-examination exhibits, so if you need to refer to the excerpt you have that there.

A. That's incorrect, it's an excerpt from our financial disclosures that's provided as an exhibit, not an excerpt from the financial accounting standards.

Q. Are you looking at Exhibit 142?

MR. GALLOWAY: 442.

MR. FFITCH: I'm sorry, 442.

THE WITNESS: I don't have Exhibit 442.

JUDGE RENDAHL: Let's be off the record for a moment.

(Discussion off the record.)

JUDGE RENDAHL: Do you have a copy of Exhibit

442 in front of you now?

THE WITNESS: I do now, thank you.

BY MR. FFITCH:

Q. Now that is an excerpt from FAS 133, is it not?

A. I will take your word for it subject to check.

Q. All right. So it's not part of your financial disclosures as you mentioned?

A. No, it's not.

Q. All right.

A. That was my mistake.

Q. Are you aware of any portion of FAS 133 that requires or endorses the use of commodity evaluation techniques as a basis for selecting new long-term resources?

A. I'm not familiar with the financial accounting standards requirements, I'm not an accountant.

Q. All right.

Just one last question in the area of the PCAM, Mr. Tallman. Is it your testimony that the UTC should allow implementation of a PCAM that exposes retail electric customers to additional risk associated with resource acquisition with no changes to

PacifiCorp's current system for external review and scrutiny of those processes?

A. My testimony simply addresses that we believe we have met the criteria laid out by witness Black, and I would defer to our other PCAM witnesses beyond that.

MR. FFITCH: Thank you, those are all my questions, Your Honor.

Thank you, Mr. Tallman.

JUDGE RENDAHL: Thank you, Mr. ffitch.

And, Mr. Sanger, ICNU has waived cross for this witness, correct?

MR. SANGER: That is correct.

JUDGE RENDAHL: Is there any redirect for this witness?

MR. GALLOWAY: There is, Your Honor.

R E D I R E C T   E X A M I N A T I O N

BY MR. GALLOWAY:

Q. Mr. Tallman, Mr. ffitch was asking you some pretty technical questions, and I was hoping that maybe we could get some basic understanding. You have described generally a interaction between the company's IRP process and your RFP process, and I was wondering if you could in sort of basic terms give us an example of let us say that IRP demonstrates a need in the west for

300 megawatts of wind power. As I understand it, that then drops on your desk, and you're the implementation side of the business, right?

A. Correct.

Q. Could you describe once that happens what you do next and how the process works through and the various considerations you give.

A. Well, simply speaking, we look at generally where the IRP lays out that the system has a need, and then we move forward to issue some sort of solicitation. And in doing so, we draft out basically a list of minimum criteria. And the minimum criteria can run the gamut from credit requirements to delivery characteristics, in this case it might be a variable resource, intermittent resource such as a wind resource, to delivery points. The delivery point on its face -- well, let me say it another way.

The location of an asset that's making deliveries to the delivery point is -- can not be incurred by the delivery point. In other words, if it's a resource in the west, we may list a number of delivery points on our system that we can accept delivery, however, the actual asset could be located virtually anywhere in the Western United States. All we're really saying is it's up to the counterparty to get up there, which is a risk assessment that we have made. That would be kind of a general example.

Q. And then you get responses to your solicitation, what happens next?

A. We receive responses that go through initial screening, see if entities have met the minimum criteria, and then we go through and we do an evaluation of each alternative against some identified benchmark. Typically the benchmark is a forward price projection. It's the same forward price projection that the company uses in any number of its processes. That's used by the FP process for example. Mr. Widmer would use it in his grid modeling for regulatory rate recovery. It's the same price curve that would be used for our financial disclosures for FAS 133 purposes. And then we make an assessment based on a judgment of the best resource based on cost and risk, and we move forward.

Q. I assume there are prices associated with all the responses that you get, can you give a real world example of when you need to bring a mark to market approach to evaluating two different proposals?

A. Well, what the mark to market approach allows you to do, and, you know, I don't personally use the word mark to market, for me it's just simply a comparison of what the counterparty is offering against what we think the value of that product or delivery pattern of the resource to the flexibility that the resource provides, it's the value of what the counterparty is offering against our forward price projections. And the linkage with the integrated resource plan of course is that the integrated resource plan dispatches against a forward price projection, the same forward price projection.

Q. If one bid says $50 and another one says $60, why do you need to look at a market projection?

A. What you need to look at is what the counterparty is offering, so if they're offering you a given delivery pattern at a price, that doesn't have context on it so it needs to be benchmarked or compared against something. And so you would compare a $50 offer with its given delivery pattern against say a $60 offer against its delivery pattern, because $60 may be a better deal for customers, it may give you a more desirable delivery pattern, something that's more valuable in the marketplace.

Q. And when would you have to bring the concepts associated with option value to bear in comparing two resources?

A. Well, option value is simply a fancy way of saying when might the resource be a value to customers, and usually option value is associated with instances where the company of course has the option to call upon a resource to provide power. And we simply are asking ourselves, you know, when we think we're going to need to call on it, do we think it will have value in the marketplace, because we dispatch all of our resources against the market. If it's cheaper to turn off a resource and buy from the market, then we will do that, that benefits customers. So the economic aspect of the resource against the market is important to us, because we want resources that will be economic on a forward looking basis.

Q. Are these sorts of analytical tools in your view inappropriate for a stodgy regulated utility?

A. No, they're not inappropriate at all, they're time honored conceptual processes that I think have probably been provided with lots of fancy names just because the electric market is tending to get more commoditized and there's more entities entering the electric market that have traditionally participated in financial markets, so they have brought with them the terminology. But in theory, it's really not much different than what we have been doing for a long time. It's just valuing of alternatives against projections of fuel or market or whatever it may be.

Q. Now as you go about your evaluation process, do you sort of ignore the IRP and the effect that a particular acquisition could have on the portfolio?

A. No, we don't, we look to the IRP for guidance in terms of laying out a road map for the company. That's why the process is so important to us, that's why we spend so much time getting stakeholder input, because the portfolio that the IRP brings forth in a high likelihood will be the portfolio that the company will end up implementing subject to receiving offers from third parties.

MR. GALLOWAY: I have nothing further, Your Honor.

JUDGE RENDAHL: Thank you.

Mr. Trotter.

MR. TROTTER: No questions.

JUDGE RENDAHL: Mr. ffitch.

MR. FFITCH: No questions.

JUDGE RENDAHL: All right, are there any questions from the Bench for this witness?

Commissioner Jones.

E X A M I N A T I O N

BY COMMISSIONER JONES:

Q. Good afternoon.

A. Good afternoon.
Q. I think you're the last on the list today, so I will be expeditious here.
What proportion of the company's total systemwide energy supply is demand from hydro power?
A. I don't know that off the top of my head, but I could -- we could get it for you if you would like it to be a Bench request.
COMMISSIONER JONES: Why don't we make that a Bench request. Do you want me to rephrase that again, Judge?
JUDGE RENDAHL: If you could repeat it, that would be helpful. It would be Bench Request 24.
Q. What proportion of the company's total (systemwide) energy supply is derived from hydro power?
THE WITNESS: May I ask a clarifying?
COMMISSIONER JONES: Yeah.
THE WITNESS: Would you like that during a normalized water year or for the water years we have experienced in the past six years?
COMMISSIONER: Let's see, normalized I think. Would that be -- I think a normalized year would be fine.
THE WITNESS: Okay.
COMMISSIONER JONES: You don't need to go

back 40 years or 50 years.

THE WITNESS: Well, just statistically it moves around, so.

COMMISSIONER: Okay.

JUDGE RENDAHL: Okay, so what proportion of the company's total (systemwide) energy is composed of hydro power on a normalized basis?

COMMISSIONER JONES: Yes.

JUDGE RENDAHL: Do you have that?

THE WITNESS: I do.

JUDGE RENDAHL: Okay.

THE WITNESS: And we will include purchased hydro power, was that your intent, sir?

COMMISSIONER JONES: No.

THE WITNESS: Owned?

JUDGE RENDAHL: Of company owned hydro power.

MR. GALLOWAY: Okay, but understanding that would exclude the Mid-Columbia for example.

COMMISSIONER JONES: That would exclude the long-term PPA's with the Mid-C?

MR. GALLOWAY: Yes.

COMMISSIONER JONES: No, I modify that, I want the request to include the Mid-C.

JUDGE RENDAHL: So company owned and purchased hydro power.

THE WITNESS: Under long-term purchase power agreements.

COMMISSIONER JONES: Thank you, yes.

JUDGE RENDAHL: Okay.

BY COMMISSIONER JONES:

Q. What percent of -- you go through Mr. Black's three criteria that he thinks are necessary for PCAM to be adopted, and one of those is a risk management policy.

A. Yes.

Q. That looks and monitors the overall trading and hedging, if you will, strategy of the company. Can you describe for me briefly, you say you do have a policy in place?

A. Yes.

Q. And there is a committee, an independent risk or independent monitoring committee that oversees the activities of you, I would assume you and the people who work for you?

A. Correct, independent organization if you will, it's not necessarily a committee.

Q. Okay. And then just go up the chain if you would. Above you how is that reviewed by the senior management team of your company?

A. The risk policy or the risk organization?

Q. The risk policy.

A. What the risk policy does for PacifiCorp is it does a number of things. First of all it lays out the organizational structure by which we will monitor and implement the risk policies of the company. So the end of the business I'm in is the commercial organization. Our job is to manage against the risk policy in terms of its limits that we set for ourselves, our position limits, as well as the amount of commodity risk that the company is willing to bear due to market movements. So our job is to implement the policy, if you will.

There's a separate -- and I report to a Senior Vice President of commercial trading who reports to the CEO of PacifiCorp. The Risk Management Organization is a separate and independent organization whose job is to make sure that we're complying with the implementation of the risk policies and procedures. They report separately and independently through a separate reporting chain right now under Scottish Power's tutelage. The Vice President of Risk Management for U.S. Operations, which includes PacifiCorp, reports to the Group Risk Director, which is a position that reports to the Scottish Power Finance Director. So it's a separate, totally separate distinct path. After the transaction with Mid American, I suspect we will maintain some sort of independent path, I'm just not sure how it will work out.

Now I think that was one part of your question.

Q. The last part of it was going up to the board, as currently structured then, how is the risk policy reviewed at the board level? Is it subject to the review of the audit committee, the full board, how are these policies reviewed and how often?

A. They're reviewed -- actually they're really constantly because we keep track of little tweaks that we need to make to clean them up, make sure they're up to date with changes and so forth. Since we're part of a larger organization, PacifiCorp has its own risk policy, and that is reviewed by the board. I'm not sure if there is a subcommittee of the board or not that actually looks after it, I think it's just actually the board. And our Risk Management Organization will make suggested changes to the policy to the board, which will get ratified. In that we have a number of risk committees, you mentioned risk committees, we have a number of risk committees within the organization which really is doing the day-to-day application. Even though my organization implements, we also are members in concert with our Risk Management Organization in review committees as certain transactions or activities float up for approval.

Q. Do you have an idea or do you have an approximate percentage of what percentage of your fuel needs are hedged going forward, either on a 24 month rolling basis or longer than that? This would be fuel.

A. And by fuel you're --

Q. Natural gas.

A. -- meaning primarily natural gas. It's a very high percentage, I'm trying to remember the exact percentage. I believe it's almost 90% to 100% for the next 12 months. For the next 24 months it's a very high percentage. I'm just not sure if we're greater than 80% or not. We just finished some field solicitation, so I'm not sure of the exact percentage right now, but it's a very high percentage. We very actively manage our forward position in fuel and electricity.

Q. In terms of the IRP and the RFP process, just a few process questions. Which state commissions require an acknowledgment letter to state that the IRP conforms to applicable state law and regulation, all six, two, three, four?

A. It's not all six. I cringe to have to defer to Mr. Duvall on this, but it's a subset of all six. I can't tell you which ones, I do know it's not all though. Acknowledgment means different things to different states, at least on their standards and guidelines.

Q. Yes, well, I'm referring specifically to our state, and our state may be unique or may not be unique, but we review the IRP, and then we send what we call an acknowledgement letter to the company that basically states that it conforms with our laws and regulations, and if there are any tweaks or improvements to the plan, our Commission states in that letter what we think they should be going forward.

A. So subject to validation by Mr. Duvall, Washington, Oregon, Utah, I'm just not certain about Idaho right now or California.

Q. And would you describe each of the state processes, all of the six processes including our state's, as being an active participation where stakeholders in each state are obviously different, but are stakeholders actively involved in both the IRP, the development of the IRP and the RFP?

A. Well, I haven't made it to all of the IRP meetings. Of the IRP meetings I have been to, there's been a broad representation. Even one of the ones I went to had customers show up, Washington customers by phone dial in. We try to make it available as wide as we can. I can represent on the RFP side that the RFP processes that we have held, the prebid stakeholder conferences and such, are broadly represented, yes.

Q. Are the Commission staffs such as the Commission, the Staff of this Commission, actively involved as well?

A. It's kind of hit and miss. It kind of I think it depends on a given situation, and a lot of times if it's a large RFP process we just simply take the time and come visit the Staff personally, which kind of negate their need to show up in a public setting.

COMMISSIONER JONES: That's all I have, Judge.

JUDGE RENDAHL: Okay, thank you.

Are there any other questions for this witness from the Bench?

All right, and I don't have any questions either, so at this time, Mr. Tallman, you may be excused.

THE WITNESS: Thank you.

JUDGE RENDAHL: And we'll go off the record for purposes of scheduling and other discussions, but our hearings for today are over, so thank you very much, we will be off the record.

(Discussion off the record.)

(Hearing adjourned at 3:40 p.m.)