Puget Sound Power & Light Company
Docket No. UE-920499
Response to Skagit-Whatcom Area Processors Data Request Number 212

Request:

For each of the 200 highest hourly loads referenced in Request No. 211, identify the month and time of day when the load occurs.

Response by Ms. Lynch:

See Attachment I, Pages 1 and 2, which identify the month and hour for each of the 200 highest hourly loads referenced in Request No. 211.

PUGET SOUND POWER AND LIGHT CO.
TOP 200 SYSTEM HOURS
TWELVE MONTHS ENDED SEPTEMBER 30, ~~1992~~ 1988 alh

RANK	MONTH	DATE	HR	SYSTEM MW	RANK	MONTH	DATE	HR	SYSTEM MW	RANK	MONTH	DATE	HR	SYSTEM MW
151	12	12/24/87	12	3,026										
152	1	01/11/88	19	3,023										
153	12	12/31/87	11	3,023										
154	12	12/30/87	9	3,021										
155	3	03/28/88	8	3,020										
156	1	01/07/88	18	3,019										
157	2	02/25/88	8	3,019										
158	2	02/03/88	19	3,016										
159	1	01/27/88	8	3,014										
160	1	01/12/88	18	3,012										
161	1	01/20/88	9	3,012										
162	12	12/13/87	10	3,012										
163	3	03/16/88	8	3,011										
164	12	12/15/87	17	3,011										
165	12	12/18/87	11	3,011										
166	1	01/18/88	19	3,010										
167	3	03/07/88	8	3,010										
168	3	03/14/88	8	3,010										
169	12	12/22/87	20	3,010										
170	1	01/12/88	19	3,009										
171	12	12/15/87	11	3,007										
172	12	12/11/87	8	3,006										
173	2	02/02/88	21	3,005										
174	12	12/19/87	18	3,005										
175	1	01/06/88	19	3,004										
176	2	02/16/88	9	3,003										
177	1	01/26/88	19	3,002										
178	1	01/03/88	13	3,001										
179	12	12/22/87	11	3,001										
180	2	02/02/88	13	3,000										
181	1	01/09/88	11	2,999										
182	2	02/18/88	8	2,998										
183	1	01/11/88	18	2,996										
184	1	01/18/88	10	2,995										
185	12	12/20/87	18	2,995										
186	12	12/23/87	21	2,995										
187	12	12/27/87	11	2,995										
188	12	12/28/87	9	2,995										
189	1	01/06/88	18	2,994										
190	1	01/21/88	19	2,994										
191	1	01/26/88	10	2,994										
192	12	12/19/87	12	2,993										
193	12	12/25/87	10	2,993										
194	1	01/30/88	11	2,992										
195	1	01/15/88	8	2,991										
196	12	12/30/87	11	2,991										
197	12	12/21/87	11	2,990										
198	12	12/12/87	10	2,988										
199	12	12/19/87	19	2,988										
200	12	12/28/87	11	2,986										

SWAP Data Request #2
Attachment I, Page 2

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant,	)	
vs.	)	
PUGET SOUND POWER & LIGHT, Respondent.	)	Cause No. UE-920499

The deposition of DAVID W. HOFF in the above matter was held on August 13, 1992, at 12:45 p.m., at 1300 South Evergreen Park Drive Southwest, Olympia, Washington.

The parties were present as follows:

COMMISSION, Donald Trotter, Assistant Attorney General, 1300 S. Evergreen Park Drive S.W., Olympia, Washington 98504.

WICFUR, Mark Trinchero, Attorney at Law, 2300 First Interstate Tower, 300 S.W. Fifth Avenue, Portland, Oregon 97201.

PUGET POWER, James Van Nostrand, Attorney at Law, One Bellevue Center, Suite 1800, Bellevue, Washington 98004.

BELLINGHAM COLD STORAGE, TRIDENT SEAFOODS, et al., Carol S. Arnold, Attorney at Law, 5400 - 701 Fifth Avenue, Seattle, Washington 98104.

PUBLIC, Charles F. Adams, Assistant Attorney General, 900 Fourth Avenue, Suite 2000, TB-14, Seattle, Washington 98164.

Marilyn Johnson, RPR
Court Reporter

ORIGINAL

CORRECTIONS TO DEPOSITION OF
DAVID W. HOFF
IN CAUSE UE-920499

Page 5, line 1	consideration should read cost
Page ~~14~~ 10, line 3	went should read want
Page 16, line 24	U-69688-T should read U-89-2688-T
Page 35, line 18	and ORA should read NR
Page 43, line 23	PRINCE should read Colstrip
Page 44, line 4	rent should read run
Page 44, line 5	rent should read run
Page 48, line 16	1783 should read 17/83
Page 48, line 17	1783 should read 17/83
Page 55, line 2	2080 should read 20/80 and 1783 should read 17/83
Page 67, line 18	costs should read losses
Page 76, line 23	U-89811-T should read UE-901183-T
Page 88, line 11	6494.57 should read Schedule 94 rate of .5700
Page 89, line 6	1783 should read 17/83
Page 105, line 8	where should read why

I N D E X

EXHIBIT	MARKED	ADMITTED
(NO EXHIBITS MARKED.)		

Whereupon,

DAVID W. HOFF,

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

E X A M I N A T I O N

BY MR. TROTTER:

Q. And would you just state your name for the record, please.

A. It's David Hoff, H O F F.

Q. And you're employed with Puget Power as its director of rate planning and administration?

A. Yes.

Q. And you've prepared testimony and exhibits in this case?

A. Yes.

Q. And those were revised by the August 3rd revisions?

A. Yes.

Q. As revised, that's the testimony that you're supporting in this case?

A. Yes.

Q. And the exhibits?

A. Yes.

Q. And I take it you were here for the testimony of the prior two witnesses and you understand the procedures that are applicable here today?

A. Yes, I do.

Q. Mr. Knutsen passed a few questions your way, and I had asked him about a couple of overall considerations for rate design that he listed in his testimony. He listed I think five factors and I focused on two. One was customer acceptability and the second one was overall economic circumstances in the area. How do you take into account the customer acceptability in your rate design?

A. I think primarily we took that into account through the use of a customer task force which we put together to give us advice on how we should prepare this case, and also through the use of the rate design collaborative. So primarily we tried to get input from our customers, and then we took -- as we made the decisions on the actual filing, that played a very important part in our decision process of which rates to use.

As far as the overall economic circumstances, I think we took that into account in general when we looked at the concept of gradualism.

The ~~considerations~~ COST of service results in this case indicated a movement which would move rates fairly severely for some sectors, and so instead of moving that all of the way, we only ~~went~~ went one-third of the way, and one of the main reasons for that, you know, there is a concept of price stability, but also that could be disruptive to businesses if they have their rates changed fairly dramatically, so I think that's the way that primarily we used the overall economic circumstances.

Q. So you weren't considering any specific condition of the local economy, whether it was robust or in a recession or whatever?

A. Not directly, no. I think we consider that it's a little bit fragile right now, that that would give us a little bit more weight instead of trying to make dramatic changes in the prices, but that was not a major consideration.

Q. So your main consideration was you need to get all the way there at some point, but for stability purposes, one-third of the way this time is a reasonable way to go?

A. Correct.

Q. On the customer acceptability factor, if you have a customer come up and say, I hate this rate

design, is that meaningful or is this an objective exercise or is it subjective?

A. I think rate design has -- we try to make it objective but ends up being subjective. There are -- there's a balancing of a lot of different factors. If a customer would come up to me and say that I hated that rate design, I would try to find out why and see if it's some general nature of the rate design and try and take that into consideration, as I would try to take a lot of other things into consideration, but in general, you know, there's no magic to assigning rates. You have to end up with some number but there's a whole bunch of things that you have to weigh. What customers think is certainly one of them.

Q. But I take it you wouldn't recommend the Commission conduct some sort of polling or that sort of thing, you try to hear what your customers are talking about and respond if you can, and stand firm where you can't?

A. Oh, definitely, I think that they shouldn't take a polling. You know, a lot of times what's in the best interests of an individual customer is not what's in the best interests to the whole group, and I do also think that one of the advantages of having something like the -- our task force is that

you get customers -- you have enough time with the customers so you can explain the situation over a period of time, and they can talk to people other than the company and try to get a better understanding of what's going on. I think in general most persons -- people's initial reactions to any rate changes is they don't want them, or they would only want them to go down. I think once they understand all the circumstances and everything, they may have a little bit broader opinion.

Q. On page ten of your testimony, you talk about company's avoided costs and you indicate that the data used in this filing is based on the avoided cost in effect at the time of the company's most recent competitive bid solicitation. Is it your intent to update your proposal if a new avoided cost is determined?

A. Yes, we would.

Q. Do you know when that determination would be made and what generally it would show?

A. No, I don't know exactly when. I do know that we have in our competitive bid cycle, have competitive bids in, but they haven't been completed yet and so I know it wouldn't start until we got those completed because the rule says that we're supposed to

include the results of those competitive bids, so that would put the earliest it could be sometime in the fall, and, you know, I don't do that calculation myself, so I don't really know exactly when it would be.

As far as your second question, what the magnitude of it is, I do know that -- well, it's my understanding that the competitive bids are coming in a little bit below the avoided costs. I think Mr. Knutsen said that a little bit earlier this morning, which would indicate that at least for that portion of the consideration, that that should be a little bit lower, but that's only one of a whole lot of considerations that go into that, and so I really couldn't tell you whether it's going to be up or down.

Q. As I indicated with the prior witness, the questions I'll be asking you today are based on your revised testimony and exhibits, and unless I specifically indicate otherwise.

A. Fine.

Q. Turn to page 19 of your testimony where you talk about elasticity estimates, and you indicate there that if price affects consumption, it affects receipts, which in turn will affect the company's ability to earn allowed revenues. Should this

statement be taken in the context of traditional ratemaking or in the context of Puget's decoupling mechanisms or the PRAM?

A. Well, I think that statement is true in either context, that the company only eventually gets its revenues through receipts that it recovers from its customers. There isn't any other magic that it gets revenues from, and so receipts should always cover revenues, and so this is true in all cases.

Now, what is different under decoupling is the direct link. There's not an identity between receipts and revenues that we've had up until we had decoupling, so there is some change there, but you still have to be concerned because you have to end up getting the dollars in the door in order to cover the revenues that you're booking.

Q. In terms of getting dollars in the door, your revenues are not threatened by elasticity under the PRAM in that any under-recovery of allowed revenues would be collected in future PRAMs, is that correct?

A. Our revenues are not threatened, but our receipts are, and so that's why I put this statement in there, is that we can't just be cavalier about elasticity, because we may not get the receipts -- we

may always be pushing the allowed revenues and so we still have to have that consideration. How this comes down to me is if we ~~went~~ want alk to make an elasticity adjustment in a case, it should be relatively non-controversial because we don't get to keep any of the extras if we address it wrong, so that, for instance, I do have one elasticity adjustment in this case.

Q. But if you address it wrong and it comes to pass that you collect too much revenue the customers will get that back, but there will be a time lag between the time they give it and the time they get it back, is that correct?

A. Correct.

Q. And when you said that you were constantly chasing revenues, are you referring to the deferral piece of the PRAM?

A. Would be showing up in the deferral piece. What I am suggesting here, for instance, some of the thought process you'd go through on marginal cost pricing is the increased marginal costs, that elasticity effect, meaning you would be getting less revenues than what you might otherwise have projected.

Now, you can pick those up in the next deferral, but then you're also trying to raise those

in rates that are based on marginal cost, which are also not recovering the revenues that they're supposed to and that's what I mean by chasing my tail. If you don't actually adjust for that sometime, realize that that's going on and adjust for it, you might never recover that increment that you're always chasing.

Q. The current deferred piece from the PRAM, the -- that is articulated by the company in another proceeding, the difference between what it was allowed to collect and what it actually collected, is some $25.8 million, is that correct?

A. That's correct.

Q. How does that compare with the price elasticity effects that you're attempting to measure here in terms of dollars?

A. I'd say that's much larger than elasticity that I'm concerned about here. You know, I'm not sure how much of a problem this elasticity is. That's why I've only offered the adjustment in the power factor portion of the case. What I'm doing is sort of noting that it could be a factor. I have done some recent studies that indicate it might be a factor of as much as three to three and a half million dollars in the residential sector, but I don't know that and so I'm willing to wait at least for a year or two to see what

might happen.

Q. Mr. Knutsen talked about price signals to customers. You heard his testimony?

A. Yes.

Q. Do you generally agree with it?

A. I agree with price signals to the customers. I don't recall exactly what -- you know, all the specifics of his testimony, but I agree in general.

Q. And the notion being that it appears that utility costs are increasing so it's important that the customers receive that signal in price, is that correct?

A. And even if they were decreasing, I would think it's important if they receive those prices, too, that the price signals they get should be relative to their, what I would call marginal cost, in some manner. That is one of the considerations.

Q. Now, the company in this proceeding is proposing a decrease to the commercial customer class, is that correct?

A. Yes.

Q. Page 31 of your testimony, you talk about low income rates, and indicate that they were discussed in depth by both the collaborative group and

the task force. Then you go on to say the task force recommended against these rates and the collaborative group did not endorse them as a concept. Would you agree that the collaborative group did not endorse the concept of a specific discounted rate for low income ratepayers primarily because of legal issues, that there was a feeling that legislative activity was needed in this area?

A. I'm not sure. It's just the legality of that. I think that several of the members thought that that was most appropriately handled by legislation because it's a social problem, not just a utility-specific problem, but certainly the legal part of it was one of the considerations, I believe.

Q. And you go on in line 22 to say there was strong support from both groups for some action to address problems of low income ratepayers, is that correct?

A. Yes.

Q. And am I correct that there was general concern for lower base rates and emphasis on conservation measures to at least -- to meet some of the concerns of the low income ratepayers?

A. Certainly the emphasis of conservation measures for low income people was I think unanimously

accepted. The lower base rates, there are -- well, I think that in general was accepted.

Q. And this is only a partial solution because at some point low income ratepayers cannot limit their consumption despite all the weatherization measures having been installed?

A. Correct.

Q. Page 35 of your testimony, you talk about your proposed experimental water heater rate. Mr. Knutsen indicated this was one of the schedules that you would propose go into effect upon its acceptance by the Commission as opposed to waiting for a rate case, something like that.

A. Yes.

Q. And on page 36, where you're explaining how the rate will work, you indicate there's a monthly discount of $5.35. Does that amount correspond to Exhibit 15, DWH 8?

A. Yes, it does.

Q. And the last figure on that exhibit shows the monthly customer credit of $5.29?

A. That's correct.

Q. And this credit shown on Exhibit 15 was not affected by any of the revisions that the company went through?

A. That's correct, because it -- you know, it's based on the costs -- as Exhibit 15 shows, that's the derivation of that number. Those costs were not affected by the revisions. However, I should point out that due to the experimental nature of this, we've been continuing to revisit the costs that show up on this page on Exhibit 15, and I am afraid that with the latest revision -- or visit that we have, and it's still preliminary so we're not changing the testimony yet, which indicate that this number will probably be lower, considerably lower, but it was not affected -- to answer your first question directly, it was not affected by any of the other revisions that were already in the case.

Q. Now, so, for example, this has nothing to do with the change from the basic residential charge down to 4.75?

A. That's right. Although, you know, I did round the 5.29 to 5.35 because that made it easily identifiable -- it made it easier for the customer I think to show that then it was just -- the basic charge, but since the basic charge changed, this basic cost did not change, so that relationship would no longer be there.

Q. I see. So normal rounding would take it

to $5.30 and now you're saying that another look might mean it's slightly lower yet?

A. Yes, another look would -- so far it's indicating it would be lower and it could be more than slightly.

Q. But your rationale for the 5.35 was to match the basic charge?

A. To match it not in a cost basis but from a customer's perspective basis.

Q. But that no longer applies so --

A. No longer applies.

Q. So you propose $5.30 as based on this exhibit?

A. I would still keep it at 5.35. I guess, you know, if you wanted to change it, it would be -- and have it based on this, it could go to 5.30. I think that what'll happen is as we continue to look at this data, we'll be -- you know, I think we can circulate what information we have, and it may be that we'll have to lower it considerably, a type of rebuttal or even before that.

Q. Would you agree that power supply from a base rate perspective has not been examined since the U-88 -- excuse me, ~~U-69688-T~~ U-89-2688-T alh case?

A. The power supply?

Q. Yes.

A. There's up-to-date power supply information that are in these rates, that's in the peak credit, is utilizing basically up-to-date information. The credits for the interruptible rates are using up-to-date information, and the marginal cost rates and the residential in the optional rates are using up-to-date information. When I say up-to-date, that would be revised when we have a new avoided cost filing, but it doesn't go back to 1988. It's more recent than 1988. What the basis of 1988 is is the total cost of service, and the total revenue requirement.

Q. And the power costs that go into cost of service in terms of developing general rates have not been reviewed since that docket?

A. That is correct.

Q. And such a review would take place in the company's next general rate case whenever filed, is that correct?

A. Yes, it would, so when we implement the concepts from this case, it would be based on a cost of service that would be updated.

Q. And would such a review also have implications for your Exhibit 15 calculation?

A. Well, if there's any more information, we would of course include it in that calculation. This is not as open -- this is not embedded cost of service, power supply information that's on this page, so I would use whatever is most available, but the change in those costs would not be that dramatic. It's basically the change in assumption that concerns us as far as the cost of that page.

Q. So Exhibit 15 is basically a forward-looking analysis of the type of credit a customer should receive for this particular role they play on your system?

A. Yes, I believe that would be a good characterization.

Q. Let's focus on some of your specific rate designs in Exhibit 12, DWH-5, and this is your proposed rate schedules that customers will actually take service under and pay rates on if your filing is approved, is that right?

A. That's correct.

Q. Let's go to Schedule 25 which is small demand, general service, and am I correct if we look at both the October through March and April through September energy charge, there's a declining block rate there?

A. Yes. I'd like to also point out, however, that the demand charge is such that there's no demand being paid on the first 20,000 kilowatt hours, so in essence that energy charge includes both a demand and energy component so that, although the energy charge goes down for an average customer, a customer with a load factor of approximately 50 percent, the actual average of both demand and energy costs stays the same. It's a little confusing and this is why we tried to break up the old Schedule 24, because that was confusing as well, and probably still is confusing.

Q. Well, I was also looking at Schedule 29, seasonal irrigation drainage pumping service. Is your answer similar for that schedule because that also shows a declining -- an apparent declining block?

A. As far as a declining block portion of it, yes.

Q. Are you suggesting that these are not actually declining block rates?

A. Yes. What I'm saying is that it depends -- because part of the rate has a demand energy cost combined, the other part doesn't. It would depend upon what the customer's load factor or the relationship of their demand to their energy, whether

their effective rate of adding both of those two components together actually goes down or not.

Q. So is it possible for some customers to be in a real declining block mode?

A. Yes.

Q. Is that appropriate?

A. I think that the rate is appropriate. I would have preferred that this rate be the -- similar to 26 in that it was just flat and not have a block on kilowatts. However, when I tried that, I found out that because this is sort of the transitional block between people who are close to the point where they -- where they have 48 or 49 kilowatts versus 51, 52, that that severely affected that change to going -- just the change going from two -- from the declining block schedule to a straight schedule, had severely impacted some certain customers.

It had the effect of significantly increasing the actual bills to some customers, even though the class as a whole had a decrease, and we found that out because we have a capability now of actually going into customer's bills on a large sample basis and price them out under the two rates. Had we not had that capability, we wouldn't have found that out, then you would have seen a flat rate here, but we

did find that out and so there's real difficulty in this transitional group, and so we had to maintain the structure of the old schedule.

Q. So in theory, you would not have proposed a declining block rate that we see in Schedule 25 and 29, but it was the specific circumstances of the customers within that schedule that led you to maintain this type of design?

A. That's correct. Again, I don't like to characterize this as declining block rate in that it's a combination of the demand and energy, it's not declining -- but that's correct.

Q. Okay. But you did say that for some customers, it would have the effect of a declining block rate?

A. That's right. It's also true that for some customers it's an increasing block rate.

Q. What other mechanisms did you consider to assure that these schedules were not declining block rates for any customer? You mentioned flat rate similar to Schedule 26.

A. That's all I came up with.

Q. Did you consider -- or would you consider now an inclining rate but perhaps less steep or in some manner phase-in, similar to your let's go

one-third of the way policy? Is there anything that could be done in that area?

A. Well, the problem has to do with the demand, and if you're going to offer any portion of the demand without charging for it. If you're not going to do that, then you can have a flat rate, which is what Schedule 26 is, but, again, because of the transitional nature of this, you've got people in the past who are getting that credit who may have been using a lot more demand than that credit is giving, and so essentially getting that demand free, that would then when you went to the new rate have this large increase, so I would -- you know, I would consider anything that might correct what I would say the straightforwardness of the Schedule 26, correct that for 25, but, you know, I was unable to come up with anything that was better than what we proposed.

Q. Why not impose the demand charge on all demand and eliminate the declining block rate?

A. Okay. That's exactly what we did originally look at.

Q. Okay. That's the Schedule 26 solution?

A. Yes, that's the Schedule 26 solution.

Q. All right. Do the rates in Schedules 24, 25 and 26 take into account that the coincident peak

load factor of the small customers was higher than that of the large customers?

A. They take into account the fact -- you know, what the coincident peak factors are for those classes of customers. I don't then separate out from the classes additional information. Basically when the cost of service analysis is run for these three classes, it looks at the classes' coincident peak factors.

Q. And you assumed a load factor of 50 percent for each of the classes in these schedules?

A. That's a load factor. That's not coincident peak.

Q. But I did -- I am shifting now.

A. That's just for the purposes of illustrating the effects of the rate. We don't assume any particular load factor for -- you know, when we're doing the coincident peak analysis, coincident peak analysis is looking at actual metered or sampled metered data and just measured that -- who is on at the coincident peak at that point. Doesn't have any load factor assumption.

Q. So the load factor of 50 percent that you show in your monthly typical bill comparisons in Exhibit 14 do not relate to the coincident peak load

factor that you used in developing your schedules?

A. Not directly, no.

Q. And so you did not -- you looked at the class as a whole, not the load factors of various sizes of customers within each class?

A. That's correct. Now, when we were looking at the impacts with this analysis I was telling you about, we did look at their actual load factors.

Q. Why does Puget need a separate irrigation rate in Schedule 29 when the general rate schedules -- Schedule 25 has seasonal rates?

A. Well, that's a good question. We have a separate irrigation rate -- historically we've had a separate irrigation rate, and there has been acknowledgment in the region that irrigation customers have separate cost characteristics than non-irrigation customers do, so we have sort of this tradition that -- you know, the existing schedule. It's my feeling that the need to have a differential between irrigation and non-irrigation is less now than it was when we didn't have that differential, but primarily because of the reasons of rate stability and continuation and that sort of thing, we did not propose to eliminate the irrigation schedule in this filing.

Q. So I got three reasons there, rate stability, tradition and separate cost characteristics. Anything else?

A. No.

Q. Let's talk about separate cost characteristics. You mentioned that that was -- the record will speak for itself, but that's been alleged by members in this customer class, irrigators. Is that something your studies have been able to confirm or deny?

A. Yeah, I'd say it's more than been alleged by the customer class. Bonneville Power Administration has a separate rate schedule for irrigation, and so it's been acknowledged I think in the region. Our cost studies don't really support the differential that we have. I should point out that, however, of the overall cost of service of the class -- when we're looking at how much that class should pay, that small class we're talking about, Schedule 29, now versus the rest of the general service class, what happens is that the total class is paying too much. Irrigation is paying less than the total class, but if you look at the relationship between irrigation and the total class and how much the total class is paying too much, my conclusion is that the irrigation

as a class is probably paying about right, so that even though there's this differential, the differential is because the rest of the class is paying too much, not because irrigation is paying too little.

Q. I would assume at some point, if the rates between the two schedules become within a dime or a nickel, there would be no reason to have a separate schedule?

A. That would be right.

Q. Turning to Schedule 31, primary general service, and focusing on the energy charge, your prior tariff for October to March was 2.8840 cents, and from April to June was 2.7467 cents. Would you accept that?

A. Why don't you go ahead and give them to me one more time.

Q. The October to March was 2.8840, and the April through September was 2.7467.

A. Correct.

Q. So this shows a decrease in the energy charge from current rates. Would you explain the reason for that?

A. Sure. Because the demand charge went up, and if the demand charge goes up, the energy charge

would have to go down.

First of all, perhaps it's best explained by looking at my Exhibit 13, and if you look first of all -- are you there?

Q. Yes.

A. If you look first of all on line eight --

Q. Which page?

A. This would be --

Q. Oh, I'm sorry.

A. There's only one page.

Q. I kept your old one.

A. So did I.

Q. I'm sorry. Start over, please.

A. Okay. Line eight, you'll see going across there, it says a percent increase or decrease, this is the percent increase that we're giving to the class as a whole. When you say there's only 1.6 percent to the class as a whole, so that it's 1.63 percent under primary which is column six, so that that means that the class itself is not changing very much, the revenues that we're allocating to that class. Then you go on down that column six and you'll see line 13, which is called the adjusted demand cost of service, of $18 million. That's how much the cost of service says out of the total cost of service should be

allocated to demand, and then you go down one row below that at 14 and at the existing demand charge, we're only collecting 14.1 million of the 18 million of the cost that the cost of service says we should be collecting, so that tells me that demand charge is set too low, and I have to increase it.

Now, because I'm not willing to go all the way at one time, I'm taking the difference which is line 15 of $3.8 million, that's the difference between the 18 and the 14 one, I'm taking that by half, adding 1.9 million to the amount of revenues collected from demand charges, leaving $16 million that I should be collecting demand charged.

The main point here is that the demand charge has to go up in order to balance demand and energy in the context of the overall revenue requirement for the class. If that goes up, and I'm collecting another $1.9 million from demand, I'm not going to be able to collect that from energy any more and so the energy has to go down.

Q. Would maintaining the energy rates at existing levels cause you to over-recover the $18 million -- oh, the $18 million is only the allocation to demand, is that correct?

A. That's right.

Q. Schedule 31 shows a demand charge of $3.61 for April through September, whereas Schedule 29 for that same period shows a demand charge of $2.30 for the seasonal irrigation customers at $2.30 being approximately 57 percent lower, and the summer charge -- excuse me. Could you indicate the justification for that difference?

A. Again, I think that you can't -- I can't really look to cost of service to get a justification for the specific differential on that demand charge. What I can do is sort of repeat what I'd said about the overall return to Schedule 29 being at about its cost of service for a class, and so therefore I think that rate in general is appropriate, and then I have the other rate in Schedule 31, and this happens to be the difference.

Q. Is your answer the same with respect to the energy charges?

A. Well, actually, if you're going to compare 29 with 31, 29 is general service and 31 is primary, and so the direct comparisons get to be more difficult because it's an entirely different class. I think that the answer would be, I guess, in general the same.

Q. If you'd turn to Schedule 7, residential service, we noticed that $5.35 basic charge was there.

I take it that should also have been changed to 4.75?

A. Yes. You may not have picked this up, but in Exhibit 14, with the revisions, there are two pages that are at the end of that, pages 17 and 18, and they basically show all of the new tariffs, all of the new schedules that were changed. When the cost of service level changed, as Ms. Lynch said it did, the way we did these allocations, because they're cost based, it changed most of the rates, and so you'll see a filed and then a revised 7/27/92. All of the rates in the revised 7/27/92 would be replacing the filed rates.

Q. I got a little confused because we got certain substitute tariff sheets, for example, Schedule 26 was the subject of revised tariff sheet where the text of the tariff was actually changed, the words, so do I take it correctly that if it was just a rate that changed, you didn't file a revised tariff sheet for exhibit purposes, but rather just showed it on page 17 and 18 of Exhibit 14?

A. That's correct.

Q. Okay. So if we're looking at Schedule 7 and we see that $5.35 is the charge there, it's wrong?

A. That's right. You should go back to the Schedule 17 to see what the latest version of the rate is, and it would be 4.75, so that the basic charge is

4.75 and 10.80.

Q. Could we go off the record, please.

(Discussion off the record.)

BY MR. TROTTER:

Q. As a response to Deposition Request No. 3, if you could provide just for exhibit purposes a revised Exhibit 12 showing all changes.

A. Okay.

(Deposition Request No. 3.)

Q. But at present we combine those summary sheets from Exhibit 14 and include them into Exhibit 12 and we've got a current proposal?

A. Yes.

Q. You discuss on page 50 of your testimony schedules 43 and 46, and you indicate that you're freezing these schedules, that they will not be available to new customers upon approval of the proposed rates. Do you anticipate closing these schedules to additional loads of current customers as well?

A. No, just closing the schedules to new customers.

Q. Why if you don't want new customers coming in, why would you want increase for new loads from existing customers?

A. I probably wouldn't, except that I think it would be a little difficult to apply a tariff on a certain portion of somebody's load and then another tariff on another portion of their load, so no great philosophical reason, it's more a practical reason.

Q. But practically speaking, you could put different meters on or something? Is that a big deal or --

A. Actually, I didn't even think of restricting it to existing load. I guess you'd have problems of establishing what existing load is. If it's the load of last year or the highest load of the last five years.

Q. Maybe the load associated with the facility?

A. I mean, you could get into something like that. I'd prefer not to, but --

Q. These particular schedules are not particularly helpful to Puget's load shape, is that correct?

A. Yeah. I think that the new interruptible schedules will be better than these existing ones. I think that, you know, they're serving their purpose, but I think we felt that -- that new tariffs would be better.

Q. On page 54 of your testimony, you're referring to the Interruptible Service Credit Firm. In the last line you indicate the company made an adjustment for lost revenues. Could you explain why, given the coupling, you would make such an adjustment?

A. Well, we wouldn't make it based on the revenue to the company's basis, because we don't lose any revenue. We are concerned about customer impacts. If you do an adjustment for lost revenue, you minimize the impacts on other customers of that lost revenue and so that's why we made the adjustment.

Q. Could you just explain exactly what adjustment you made?

A. We subtracted off the amount of money that we would have collected from the customer had he generated instead of interrupted.

Q. And you subtracted it where?

A. From the value of the interruption, so that the value of interruption was then decreased.

Q. On Schedule 35, back to the irrigation tariff, you show a basic charge of $105. Am I correct that's an increase from $48.55?

A. That's correct.

Q. And the same is true for Schedule 43, interruptible primary service, for total electric

schedules?

A. I believe that's correct. Just let me check. Yes, that's correct.

Q. Would you explain the basis for that increase?

A. I think we wanted to make the basic charge comparable -- wanted to make it comparable with the basic charge in Schedule 39, and so Schedule 31, 35 and 43, which are all primary general service customers, will all have the same basic charge.

Q. So Schedule 31 that drove the costs and just the comparability policy caused the application --

A. That's right.

Q. I notice schedule 35 says the basic charge is $105 plus, and Schedule 31 does not contain that word plus and schedule 43 also does not contain that additional word. What is the reason for that?

A. I think that is an error. The basic charge is $105.

Q. We can disregard the plus?

A. Disregard the plus.

Q. Nothing further. Thank you.

E X A M I N A T I O N

BY MR. TRINCHERO:

Q. Good afternoon, Mr. Hoff.

A. Good afternoon.

Q. A couple of quick questions here. Do you have copies with you of your responses to WICFUR data requests?

A. Just happen to have some, yes.

Q. Great. I would like to have you turn your attention to request 310 and your response to that.

A. Okay.

Q. And your response basically is the attachment of a long-term firm avoided cost forecast for the company. On page 11 of that document, the paragraph in the middle of the page that says, "The total avoided cost for the combined cycle combustion turbine must be broken into seasonal firm energy and capacity components as was done for the BPA and ~~ORA~~ NR alw rate."

Would you please just describe the rationale for the seasonal differential there?

A. First of all, this is prepared by the power supply people, so I take this as fact, but I will give you my understanding of this, is that I think everybody feels that there probably should be

some sort of seasonal differential. Very few people know exactly what it should be. BPA has been bold enough to actually have a seasonal differential in their rate that they charge to us in the NR rate, and so having nothing better, we picked up that, and then utilized it to establish our differential.

Q. Fair enough. If I could refer you to your testimony at page 12, lines 12 through 15, where you discuss the determination that a reasonable estimate of the difference in time of day costs -- no, I'm sorry. Got the wrong page. "For purposes of determining capacity costs, you've taken the midway point between the cost of a one-year capacity contract and the full fixed cost of a CT," and in response to WICFUR's data request No. 313, is it correct that you said that "this assumption was a professional judgment," is that right?

A. That's the answer I got from the power supply people of what would be an appropriate number. It's also very similar to the calculation that takes the half of a cost of a simple cycle CT and then compares it to -- or compares it to the combined cycle CT when the -- peak credit type method, so when we ask these questions to the power supply people, we generally tend to get answers like this, that this is

reasonable, you know, they're in the business all the time, they get -- you know, they have a good feel for this, but --

Q. In giving you that response, have they provided you with any of the considerations that they look at that provide them with the basis for this professional judgment?

A. Just verbally they basically say that it should be about halfway between this and this. There's a whole lot of things that are involved in this, and so that's what it should be.

Q. Would it be reasonable to assume that other professionals may make a professional judgment that say three-quarters of the differential would be appropriate?

A. Well, I'm sure our professionals are better than your professionals, but yes, I'm sure it would be.

Q. Okay. That's good. All right. Follow up on a couple of questions that staff counsel asked a few moments ago. First regarding Schedules 48 and 46, you mentioned the pragmatic concerns that kept you from limiting or prohibiting new additional loads from existing customers.

Do you have any estimate of the cost to

the company of actually trying to meter separately new loads for existing customers from existing loads and trying to charge them a different rate on each?

A. I'm sure we would have that kind of costs. I don't know. It's probably in the data here someplace about what the cost of metering would be, but I don't have it off the top of my head.

Q. And is it correct to say that the company in this rate design proceeding does not intend to propose --

A. That's correct.

Q. Regarding the interruptible service credit, I believe you stated that the lost revenues adjustment actually lowered the value of interruption by the amount of revenues lost, basically.

A. That's correct.

Q. Is that correct? And you stated that that was done in order to minimize the impact to other customers?

A. That's right, because essentially other customers would make up in their rates that differential. At least eventually.

Q. At least eventually. Would that -- isn't it correct that that would occur after the next general rate case?

A. That would be in the next PRAM, essentially, be the next -- would show up as some small increment in the deferral which would show up in the next PRAM.

Q. Do you have any estimate of the magnitude of that?

A. I think it would probably be pretty small.

Q. Like to make a deposition request, Deposition Request No. 4, I guess it would be. If you could by customer class provide the impact of not having made the lost revenue adjustment, the value of interruptible power, is that possible?

A. Can I ask -- well, I'll have to assume how much we're going to interrupt. I mean, I can do it on a kilowatt hour basis. It's a very simple answer.

Q. That would be fine.

A. Okay.

(Deposition Request No. 4.)

MR. ADAMS: Could you restate that?

MR. TRINCHERO: Sure. What I've asked the witness to provide is a document that will show the impact on other customer by customer class of the company not having subtracted the lost revenues from the value of interruption in the interruptible rate.

MR. ADAMS: Thank you.

MR. TRINCHERO:

Q. Do you have copies of your responses to staff's data request?

A. Yes, I do.

Q. Could I turn you to the response to staff Data Request No. 21?

A. Okay.

Q. In that data request, you were asked to provide the average marginal cost of serving an additional customer in each of the following service classes, residential, secondary voltage, primary voltage, high voltage, street and area lighting and firm resale, and in your response you have attached a schedule of avoided costs which I believe was done in 1990, is that correct?

A. This has September 1991? I believe it's September 1991.

Q. Right. September 1991. At the end of the first paragraph you have a note, "no analysis has been done for high voltage street and area wiring for firm resale customers." Do you anticipate that the company will be doing such a study or an analysis in the near future?

A. We don't have any plans to do one right now.

Q. Also is it your position that the schedule of avoided costs is the same as the average marginal cost?

A. You can calculate from the information given on the schedule of avoided costs a marginal cost for whatever characteristic that you're looking for and for whatever time period you're looking for, so I guess the average marginal cost is a very broad term. What I would say is that avoided cost information can give you a marginal cost of marginal -- marginal resource cost for whatever assumptions you want to make.

Q. I have no further questions. Thank you.

E X A M I N A T I O N

BY MS. ARNOLD:

Q. Are you ready?

A. I'm ready.

Q. Mr. Hoff, turn please to page 12 of your testimony, Exhibit 8.

A. Okay.

Q. The question at line 16, SWAP asked you approximately the same question, and we received an answer in the response to SWAP Data Request No. 214. Do you have that with you?

A. Yes, I do.

Q. Now, you were asked to provide your avoided cost and seasonal values of power data which you referred to in your answer -- in your testimony to evaluate the seasonal cost variation, and you referred us to three other documents, and I would like to refer you to those now.

A. Okay.

Q. You first of all referred us to the response to WICFUR Data Request No. 312 for seasonal power cost variations. Do you have WICFUR -- response to WICFUR's No. 312?

A. Yes, I do.

Q. Now, will you explain to me how you used the company's hourly resource cost information to evaluate the seasonal cost variation?

A. I hope I can. This information -- we referred to this around the shop as the tea leaves, because this is the tea leaves that the power supply people look at to come back with information that says there's a six mill differentiation between summer and winter. Something they have to look at that hopefully we can look at to find the information.

But basically this is supporting the contention or the statement in my testimony that

there's about a six mill differential between summer and winter energy, and so the way they get that from here is -- what they've done is this is a representation of information that they look at on a continual basis, and they look at all these costs and they basically dispatch, and buy and sell based on cost that shows up on a sheet like this. And so when they're looking at the market, when they say there's a six mill differential, what they tell us is that in looking at the market at any point in time, it appears that in the wintertime versus the summertime the cost is about six mills difference, and they have high load hours versus the low load hours, it's about a four mill differential, and in the -- and let me see if I can help you try to understand how they get this information from looking at this.

Let's start with say the first page. This is a typical day which they after looking at some information picked as June 13th, and then what this table shows goes to -- going across the columns you have first the type, which is coal generation, oil and gas, Puget hydro, mid-Columbia, et cetera. Then you have the types of resources, Centralia plant, ~~Prince~~ COLSTRIP alw, we also have generation under mid-Columbia, et cetera. Then you have the important part, one of the important

parts, which is the incremental rate, and that is the price that this resource is costing them or their estimated price that this is costing them on an incremental basis, if they ~~rent~~ RUN alh it versus if they don't ~~rent~~ RUN alh it, if they get the value from the contract or if they don't.

Then the next columns, the 24 columns after that are each one of the hours of the day, and then reading down that you'll see how many average megawatts we get from each one of the resources that are on the left, and so, for instance, on this day at 1:00 in the morning, we got 36 average megawatts from Centralia, and an incremental cost of 8.32 mills, and at 2:00 in the morning we got the same amount, the same costs, 3:00, et cetera, and then all of a sudden at 11:00 that morning went up from 38 average megawatts to 119 average megawatts, and so reading across you can see how many resources we got, how many megawatt hours we got from that resource, and then what you do is you go down then through all of this to go up to the bottom, which is the load, which is what they're actually having to buy all these resources for, and you see at the very bottom that at 1:00 in the morning when they were serving a load of 1510 average megawatts, and if you had looked at each

one of these resources, they'll add up to that, and if you continue to go over at 1:00 in the afternoon, 1300 hours, they got 2223 average megawatts. This is all a long explanation to get to the point that the real marginal resource on this thing shows up in the secondary purchase and secondary sales, and you'll see in June of 13 that we were -- there's a lot of sales there. They show up as minuses instead of pluses. There's a PGE sale to San Fran -- sale at 12 mills. There's a PGE sale at 11 mills. There's another PGE sale at 12 mills. Well, looking at that, it appears that that marginal resource was costing us about 12 mills during that summer period.

Okay? Now you go to the winter, and let's look at -- let's go two pages down to the typical day, 1-2-91, and you'll see that you have some resources there that are more expensive on the second purchases and here they look like they're around 22 mills, 24 mills, 25 mills, so that appears that if you look just at that summer month versus that winter month, there was a differential of around 12 mills.

Now, when they look at this in general, they think, well, in general that's kind of around six mills but in this particular case it was 12 mills.

Then they also look at the time of -- at the hourly differentials as well between morning and evening. Probably not as concerned about that. But that's one of the pieces of information. So these are sort of existing daily sort of differentials.

Then the other -- so that's now I used that information, and from power supply telling me, they say this stuff averages out to around six mill differential. They can't point to specific things other than stuff like this, and, you know, sheets of this, but they tell me about six mill differentials. But then what -- you know, I need something a little more concrete if I'm going to base a summer/winter differential, and so then I look to the avoided cost numbers.

Q. Before you get to that, let me stop you here.

A. Okay.

Q. How do the power supply people decide what's winter and what's summer for purposes of making this six mill differential?

A. You know, I'm not sure exactly what their definition of winter and summer is, because generally when we talk it's in terms of winter and summer not, you know, November, December, February, March, April,

versus October versus November. I think that generally when we talk in the company, we're talking about winter in the terms of November -- October, November, December, January, February, March, the period that our rates changed. That's what I always think of because it's a period when our rates changed. Maybe that we miscommunicate sometimes because I'm not sure what they're thinking, but I always talk in terms of the rate differentials, put the year into two equal parts and start the first one -- the winter one in October and the other one in May.

Q. Go on. You were about to testify about the avoided cost study.

A. Okay. So then we have the avoided costs, I think 310.

Q. Right. I think --

A. We already talked about it. Then there is --

Q. Wait a minute. Before you go on, you talked about that in somewhat of a different context. Tell me how you used the avoided cost study to evaluate seasonal cost variations?

A. I'm sorry?

Q. How do you use the avoided cost study to evaluate seasonal cost variations?

A. Okay. If you look at the page 15 of that study, last page, should have two columns that say -- one says winter and one says summer.

Q. Right.

A. That shows a differential that they have for a cost between summer and winter, and so what we do, what we have done is, you know, in order to use that information, you have to have some load that's -- characteristics of load and you have to have characteristics of demand, and so with certain assumptions you can then use this information to come out with what the actual cost is, summer or winter. And so what we've done is taken this information and actually -- we've updated it because this information is based on a demand energy split of 20/80 which is what we used to always use. Now we're using ~~1783~~ 17/83 alh, so this was updated to a ~~1783~~ 17/83 alh differential, so it's not exactly these same numbers. Basically we put it into a model that just calculates based on certain assumptions, and what -- where we got our 10 percent differential is looking at water heat, the characteristics of water heat load for 12 years, and then separating that into the costs that occurred in the summer, according to this analysis, and the costs in the winter in this analysis, looked at those two

differences and they were 10 percent different, and so that's the foundation for the actual number of 10 percent.

Now, I want to caution you that this is not 10.00 percent of an accuracy of -- it's like between five and 15, and in fact, you know, used to be five. We felt that five was probably too little, so we needed to change. We have some numbers that indicate at least for a particular type of load 10 percent is a good number. It's probably better than 15, and so we used ten percent, so it's not highly accurate but it does respect the fact that most people agree that there are differentials between summer and winter.

Q. The differentials in the avoided cost study define winter as September through March, and for your tariffs you define winter as October through March. Do you take that difference into consideration?

A. No. It's probably -- the September is probably a bit of an inconsistency there, but again it's not in the magnitude of the rounding that's going on, doesn't bother me.

Q. In your answer to SWAP Data Request No. 14, you also refer us to the winter and summer

marginal water heating cost as described in response to staff Data Request No. 10, and I think you just mentioned that.

A. I just explained that, yes.

Q. Would you turn to the response to staff Data Request No. 10, please?

A. Yes, uh-huh.

Q. Why did you choose the water heater customer as your reference point?

A. That's a reference for several things. It's the reference for our -- for the tail block, for the marginal cost rate, and I think the reason is that is number one, residential sector is the largest sector, number two, water heat is one of the largest loads of that sector, 75 -- over 75 percent, I think it's 85 percent of our customers, have electric water heat, so it's a fairly large load. It has characteristics that are similar to a lot of other loads particularly in the residential sector. The focus is, I must admit, primarily focused on the residential when we're looking at this stuff, and that's again because residential is a little over half of our load, and so we just felt that water heat being representative has the load shapes that are similar to a lot of other load shapes in the residential sector,

with the exception of space heat, and it was a fairly large load, lot of customers had it, that that would be a fairly representative load.

Q. Is the water heater load consistent between summer and winter? Is it about the same?

A. It has some load that's higher in the winter than the summer. There was a response to a data request, I don't remember where it was now, that actually shows the load profile for the residential sector, and it does show that there is some differential between summer and winter. That would be response to staff's Data Request 20.

Q. Thank you.

A. Yes.

Q. In your answer to staff Data Request No. 10 about three-fourths of the way down on that paragraph, you say "it," meaning the differential, is meant instead to be a rough estimate of the magnitude of difference between the seasons. The 50 percent differential and the demand rate is a similar rough estimate of magnitude which reflects the impacts of coincident and non-coincident costs on a demand charge, and is new to this filing. Would you explain what you meant by that last sentence, the one that begins with the 50 percent differential?

A. Well, yeah. First of all, the last part of it is easy to explain. We haven't had a differential in demand charges before.

Q. Right.

A. And I think that the collaborative group felt that -- and I think most of us think that there should be a differential, and so we attempted to put one in. The first part tries to roughly explain how we get this 50 percent differential. What that -- how we do that is basically look at costs that -- see, first of all, you've got to start with the notion that demand costs really are annual costs. I mean, they occur once, but generally are collected over a 12-month basis.

In other words, there's a winter peak demand and coincident peak demand, but you have to -- generally you don't want to just charge it on that day, you want to carry it over a 12-month basis, and so you look at the types of demands and you look at the coincident, meaning everybody is on at the same time that the system is having their peak, generally in the wintertime, and there's certain costs related to that that probably should only be collected during the winter months.

Surely someone that's on in the summertime

and not on in the wintertime will not participate in that kind of a demand, system energy demand peaking. However, their other costs, the non-coincident costs, that could occur year round. They're based on when that customer has its peak, and that could be in the summer or fall or winter, so we want to try to have a demand schedule that divides those costs that could occur year-round on a year-round basis, and so you would divide the charge -- look at the charge over a 12-month period and if it's $100, $120, you divide it by 12 and charge $10 per month. The ones that will only be occurring in the wintertime, you would probably only want to charge during the wintertime, and so where that 50 percent comes from is looking at what happens if you only charge the production related demand charges for a six-month period in the wintertime. So you're taking a cost and dividing it by six versus all the other costs that you would be dividing by 12, and when you do that, you get a differential that's roughly in the neighborhood of 50 percent, and again it's roughly in the neighborhood because this is not precise in any manner, but it does reflect a differential that I think is more supportable than having it flat and having it constant. Did you understand all that?

Q. Well, sort of. This morning Ms. Lynch said that she believed that in determining the seasonal differential, that you used certain information from the cost of service study regarding the allocation of -- regarding the allocation of demand related costs by functional category. Was she right? Did you rely on some parts of the cost of service study?

A. Yeah. I looked at the production related costs versus -- demand costs versus other demand costs.

Q. Are there any other parts of the cost of service study that you used in order to arrive at the seasonal differential?

A. In demand?

Q. Yes.

A. No. It's basically that portion of it.

Q. Were there any parts of the cost of service study that you referred to in defining the seasonal differentiation in the energy charge?

A. No, because, you know, basically this is not an embedded concept but it's a forward-looking concept, and it's looking at the marginal costs that are in the future, not the costs in the past. I mean, there is a relation between them because, as I

mentioned, the peak credit method -- when we changed the peak credit method from 20/80 to 17/83, that changed the values of this avoided cost numbers, so -- and -- so, you know, they're consistent in that when she looks forward she's looking at the same sort of stuff that I'm looking at here but I don't look at embedded numbers, it did not look at embedded numbers when I did this other than the production demand, production related demand.

Q. Please turn to page 45 of your testimony, line 21. You're talking about Schedule 29 which is the -- one of the irrigation tariffs. You say the -- line 21, existing rate advantage for Schedule 29 is roughly equivalent to the excess over parity which our cost of service study suggests is currently being paid by the general service class. Would you explain that?

A. Yes. If you'd look at Exhibit 13 -- actually maybe it's better because I didn't look at all those classes, maybe it's better to -- let's see. The testimony on page -- why don't you look at page two of the testimony. The reason I'm doing that is because Exhibit 13 has the three subcategories and actually I looked at the total, but in that you see that the parity ratio for a secondary is 1.25. That means that when Miss Lynch runs her study, that

indicates that that class is paying 25 percent more than it should, that it's subsidizing all the other classes, essentially. Well, that means that rate is too high.

Now, irrigation is less than that, and it's part of that class, Schedule 29 is part of that class, and has lower rates. Well, the rates that are lower are lower by about 25 percent, and so that would indicate to me that their rates probably are about right, so instead of lowering everybody in that class, including 29, down, I should lower 24, 25 and 26 down, but keep 29 about the same, and in fact there was a little bit of differential as I calculated it and it should actually get a little bit of an increase, but essentially what it's saying is as part of that class, class in general is paying more than what it should, 29 is not paying what the rest of the class is, paying about 25 percent less. Well, that probably looks like it's okay.

Q. Now, the parity ratio is different for the primary classes.

A. That's correct.

Q. How does Schedule 35 compare to the other primary customer classes?

A. Not so well.

Q. Can you explain?

A. Well, 35 has had an -- you know, again back with the history of the irrigation, it had a lower rate. It appears to be lower than the class as well. I probably could have increased that rate up substantially. I chose not to at least in my filing because it would be a fairly probably dramatic change. It's a very small account, so there's not a lot of dollars involved, but I don't have the same explanation for that as I did in 29.

Q. Now, 29 and 35 are limited to irrigation and drainage pumping, and the eligibility is tied into Bonneville's rate schedules. Is there any reason why those schedules couldn't be -- why Puget's Schedules 29 and 35 couldn't be expanded? Is there some reason why it's limited to the same type of customers as Bonneville defines them?

A. I guess you could define any customer class that you want to define. I think once you start expanding definitions, then you get sort of away from the original definitions. I would -- I prefer not to have the specific rates for small groups of customers. I probably -- I guess that I would have to -- you know, if I was going to be asked to expand it, I would have to look to make sure that all the characteristics

are very close to the same. I would certainly prefer not to expand it. As a matter of fact, these schedules, I'd probably prefer to contract them, but I would definitely prefer not to expand them, but other people can make a case to expand them, I suppose.

Q. Well, would you agree that if a group of customers had loads that were similar -- had similar characteristics to the irrigation or drainage pumping customers, that they should fit into the -- these schedules as well?

A. Yes. If cost of service was the only criteria for the classification of customers, I suppose I would. I think that -- you know, I'm not sure why BPA identified irrigation specifically. I have a feeling cost of service was one of the justifications but not the only reason, and, you know, there are lots of criteria about whether rates are -- you know, in setting rates. Certainly cost of service is a very prime reason in my thinking, but there are other reasons as well.

Q. Did you do a -- I think you talked earlier about doing a coincident peak analysis for various customer classes. Did you do a coincident peak analysis for Schedule 35?

A. I believe there was one done.

Q. Can you refer that to me? Is that in the exhibits or the data requests?

A. Yes. It's Exhibit 5. Non-coincident demand factors, is that what you were asking, the non-coincident?

Q. Yes. It's Exhibit 5?

A. Yeah, CEL-4. It's Miss Lynch's exhibit. I'm not sure that's -- okay. So it's page three, or the third page -- yeah, does say page three, and you'll see that the column headings, there's a coincident demand factor, non-coincident demand factors, and under non-coincident demand factors, there's demand two.

Q. What's that mean?

A. It's one of the three types of factors that Ms. Lynch uses. Demand two, demand three and demand four. They're different type of coincident demand factors. I think they have to do with whether they're primary or second or general service, and then you'll see, for instance, primary irrigation service would be line ten. That would be Schedule 35, and you'll see in demand two they do get a non-coincident peak allocation of .0003768 percent of all the costs that are allocated under that factor, or their non-coincident peak in kilowatts is 1,507.

You'll see in demand three and demand four that under her cost of service study they don't get any allocation.

Q. Did you consider this data in arriving at the 50 percent differential and demand charges?

A. No. That wasn't -- let's see. Did I consider -- to the extent that this data influences a demand -- the total aggregate demand numbers that I used, yes, I did, but I didn't look at specifically primary or, you know, any of the specific classes like this.

Q. In other words, if I understand what you're saying, you used this data in arriving at the 50 percent generally, but you didn't apply it to any particular class?

A. That is correct.

Q. Do you think that you might have arrived at a different differential if you had applied it to specific classes?

A. Well, I could, but I think that that would be a misuse of the -- of the magnitude of fuzziness of that number, I guess. In other words, it's a general -- general way to split demand between summer and winter. You could say apply that sort of general concept specifically to any class you wanted to, I

guess. I think that that would be -- I would personally not prefer to do that that way. I would think that that would be misconstruing the accuracy of the concept.

Q. You mean of the 50 percent differential concept?

A. Yes, uh-huh.

Q. Back to the definition of October through March, somewhere you said in answer I think to a data request that the company in 1980 changed from some different definition of summer and winter.

A. I think that was from no definition of summer and winter. I'm not sure. I remember answering that data request and I think what that said is that in U-7805, which was a generic rate design case that everybody in the state talked about rate design and these issues, that the concept of summer and winter came up then, and that when we applied it -- well, maybe I'd better get the thing because I'm not exactly sure. This precedes me. I think -- let's see. Was that one of your questions? I think it was.

Q. Oh, look at the response to SWAP Data Request No. 207.

A. Yes. When it says the company established

the need for seasonal rates in U-7805, I think what that really -- I don't think there are any actual rates applied then, but the first time they were applied were April -- was Cause U-8010. I don't believe we had rates before that. I think I could check that and correct that if you want me to.

Q. I'd appreciate that. Also I guess this is deposition request number five, if you could supply us, if there is any, with the rationale for that decision.

MR. TROTTER: What decision?

(Deposition Request No. 5.)

BY MS. ARNOLD:

Q. To define summer as April through September and winter as October through March.

A. I did try to research a little bit on that, and it's basically winter is in the wintertime and summer is in the summertime. I think that's the depth of that decision, that it seemed like a good idea to start this thing in October, and, as I indicated, we really haven't revisited it since then, it's just sort of been a tradition and so we really haven't looked at it since then.

Q. If the company were presented with data that showed it should be a different definition of

summer and winter, would the company consider changing it?

A. Are you asking do we ignore any new information? Sure, we would consider changing it. I think we would have to look at it to see if it was a compelling reason to change it because we do have the tradition and now the PRAM cycle is based on these rate changes at this time and all of that.

Q. Is there any reason why summer and winter are defined the same for purposes of the demand and the energy charge or again is it just tradition?

A. I think tradition is probably the reason.

Q. If you would turn to your Exhibit 11, to Schedule 30.

MR. TROTTER: What's the exhibit reference?

MS. ARNOLD: Exhibit No. 11.

THE WITNESS: DWH --

MS. ARNOLD: DWH four.

MR. TROTTER: That's the final report?

MS. ARNOLD: This is the final -- no, I'm sorry. I gave you the wrong -- it's Exhibit No. 12, DWH five. It's the sentence that contains the proposed tariffs.

THE WITNESS: Yes.

MR. TROTTER: And you're on Schedule 11?

MS. ARNOLD: 30.

MR. TROTTER: 30?

BY MS. ARNOLD:

Q. Are the rates on this experimental schedule based on marginal costs?

A. Yes. The split -- well -- yes.

Q. Looking at the seasonal differentiation on the tail block of the energy charge, the difference, as I calculated it, comes out to about 15 percent. I don't understand why it's 15 percent instead of 10 percent.

A. That's because the time period that we ran this marginal cost on, these are the actual marginal costs for a certain time period, and that time period was different than the time period that we ran the marginal costs that got the 10 percent differential, and so depending on the time period, you can get a 15 percent differential, looking at the avoided cost table. You know, it's a function of the relationship of energy to demand that you assume, and also the number of years that you assume.

Q. What's the relationship between energy and demand you just referred to?

A. What is that?

Q. Yes.

A. That would be, you know, the number of kilowatts that you're assuming every month versus the amount of energy, commonly called the load factor.

Q. Is there a high degree of correlation there?

A. Correlation for --

Q. Between the amount of energy and the demand?

A. Depends on the use. If you have water heat, you know, demand is fairly stable and energy is fairly stable. If you have space heat, you'd have a lot of demand in the wintertime and not much in the summertime. It depends on the type of load that you'd have.

Q. Look at Schedule 46. Well, no, never mind. Strike that.

Changing directions here, I would like to ask you some questions about the power factor charge. If you'd turn to page 20 of your testimony, at line 12, you say we have incorporated elasticity effects into our calculation of the impact of the proposed power cost adjustment. Would you explain what you meant by that?

A. Sure. Maybe it would help if we turned to

WICFUR's Request No. 316, because I think I -- maybe I'll explain it just briefly and if you want to get into the details we can do it based on that.

Q. Okay.

A. But basically what we did is when we changed the way of calculating the power factor effect and going from the KVAR hours that we currently are doing to the new way, it increases the effective rate of having a poor power factor by a factor of about double.

Now, being the economist that I am, I think people probably react to that kind of a change, and so what I did was assume that they would react depending on what their power factor was and the size of their load and what it cost them to make the adjustments that would require them to improve their power factor. And so then I just made several assumptions based on that and came to the conclusion that if you just increased that rate -- or increased the power factor just by itself, you would get so much more demand, if you will, or more money, but that because of the reactions of customers to that price change, that that effect would be minimized and in fact you'd only get 75 percent of that effect instead of 100 percent of the effect, and that's what this

response to WICFUR 316 tries to walk through is how I did that calculation.

Q. Well, I'm not sure I understand that, but I'll leave that for now. Currently -- well, let's take Schedule 31 as an example. Current Schedule 31, and I think the other primary service tariffs, includes a reactive power charge of .025 cents per KVAR hours, is that correct?

A. That's correct.

Q. Is that KVAR hour charge based on cost of service or what's it based on?

A. It's based on the cost of the company correcting for the -- partially for the effects of the power factor. It's based on the cost of capacitors which is how the company does its correction. The reason that we went to change is that's not all of the costs involved in this, and there's -- now, there are line ~~costs~~ LOSSES involved, the fact that we have to have more demand to push the poor power factor through, additional costs that this really isn't fully correcting for, and so we felt that we should make this more consistent with the way we're treating this with the large customers which is where we actually meter KVA or the effective power instead of the kilowatts.

Q. Is the new power factor adjustment that the Schedule 31 includes -- actually I guess it's under Schedule 80, is this cost based, and if so, what costs is it based on?

A. Yeah, actually, what it does, it essentially changes the denominator, if you will, of the costs. We have certain demand costs. Those costs are what they are. If you're -- you can either divide those by kilowatts or you can divide it by kilowatts that are adjusted for the power factor. And so essentially how this is cost based, it takes the actual cost but it's dividing them by actually a number that's slightly larger than it would be if it were kilowatts because we're measuring the effects of these power factors, so it's something closer to measuring them for KVA which is what we do for our large customers.

Q. Now, you mentioned that in your testimony that other utilities in the region also use a power factor adjustment. I think you mentioned Snohomish PUD and Tacoma City Light and some others, but they have a base level of correction that ranges anywhere from 85 percent to 95 percent. Why did Puget choose 95 percent instead of 85 or 90 or some other

correction?

A. Yeah. I think we felt that as long as we're going to correct for it, that 95 was preferred to something that -- you know, basically if you do it at 85 percent, people are getting away with, if you will, or not paying for 15 percent change in the power factor. If it's 95 percent it's only a five percent differential. Well, I don't think anybody suggests that we should go to 100 percent because there is a little slop in there and that would mean that we would be charging a whole lot of customers for just minimal amounts of changes, and also, you know, there are parts of our load that are not demand metered that get a demand charge and so they're -- so we don't think we should go to 100 percent, and I just personally think that as long as we're going to do it we should go to something more than 85 percent. It's a judgment call.

Q. That's not a cost based decision, then, it's a judgment based decision?

A. It's a judgment based decision based on whether we think that the people who are causing the problem should pay for it or not or only a few percentage of those people that are causing the problem should pay for it.

Q. Do you have WICFUR Data Request No. 319

there?

A. Yes, I do.

Q. Now, as I understand this, what this response shows is you're saying that the cost to install capacity -- capacitors near customers with power factor problems is comparable to the additional revenues Puget will collect from its power factor adjustments, is that right?

A. That's correct. With the caveats down at the bottom that we really can't do that. I mean, that's not really a viable alternative, but to give it an indication of the relative cost that's appropriate.

Q. Would this inability to install capacitors in some areas affect one class of customers more than another, for example, might the Schedule 24 customers be more difficult to install capacitors for?

A. I really don't know that.

Q. You didn't look into that at all?

A. I personally didn't, no.

Q. Now, you say I think in this answer that the costs of installing capacitors is about equal to the additional revenues, but it doesn't seem that the revenues -- that the penalties are comparable. For instance, if you look at Schedule 24, the cost to correct are about, what, 72 percent of the cost to

Puget, I mean, the customer cost is about 72 percent of Puget's cost, but if you look at 31, Puget's costs are only about a third or so of the cost to the customer.

Did you consider how these should be allocated among the different customer classes in an equitable way?

A. No, because we don't consider this to be a viable option. I mean, this rate is based on not the cost of correcting the problem with installing capacitors. Again, remember that that's only a portion of the cost to the company. But this rate is based on a -- the cost in general of poor power factors and the relationship of KVA to KW's, and that's a general sort of relationship and that's not specific to exactly who is doing it and all that sort of thing.

Q. Well, am I wrong then in looking at these numbers that to say that it looks like the problem is greater for schedule 24 than it is for schedule 31?

A. What that says is if we were to have installed capacitors, if we the company were to install capacitors, it would cost us more to do that for Schedule 24 customers than the 31 customers.

Q. Cost a lot more?

A. I'm not sure that's all the cost of the poor power factors are, though. The loads on 31 are fairly large per customer. There's I square R losses related to that.

Q. What are I square R losses?

A. Got me. It's the loss associated with forcing the kilowatts through the lines, and with poor power factors you have to put more force behind it and so you have more loss in the line, and so the energy that comes out at the end of the line is less than the energy that you produced at the start, and our costs related to what we generate, what we get out of it is what the customer ends up having, and the more losses, the less the customer is getting.

Q. Did you calculate the amount of these other costs other than installing capacitors?

A. Well, the engineers who we consulted on this basically have, you know, looked at all that sort of information. As far as recalling a specific dollar amount, I don't recall that I looked at one of those, but, you know, basically when we talked about this, they said, well, this is only part of the costs, there's all these other costs, and they're large, too.

Q. Could you supply us with -- are you saying that they know the specific dollar amount, you just

didn't see it?

A. No, I'm not saying that they know it, I think that they have a concept of it. Whether they've actually converted that to actual dollars or not, I don't know.

Q. Well, would you agree that for class -- Schedule 31, it would be cheaper for everybody just to install capacitors and not apply this power factor adjustment to their bills? Wouldn't that --

A. Well, it would -- if we could, again, given the caveats, install the capacitors and my understanding is that that doesn't solve all of our -- all of our questions, all this says is that the cost of us to installing the capacitors is less than what we're charging the customer in the bills.

Now, the customer -- I don't know what it's going to cost the customer. May cost the customer half of what it costs us and could be it's even a lot less expensive and could be this is a completely avoidable cost. This is not like regular energy costs because the customer can do something to avoid it. They can install their capacitors.

Q. Well --

A. And I don't know what that cost is.

Q. Would you say installing a capacitor is

about $1,600?

A. Well, that's from what I understand is on our system and I don't know on the customer's side what those costs are. I really don't know. I mean, it could be that it's exactly the same.

Q. Seems as if it might be cheaper for a customer just to pay for the cost of installing a capacitor rather than pay this power factor adjustment. Would you agree?

A. Yes.

MR. TROTTER: Is this an appropriate time for a break?

MS. ARNOLD: I think I've got -- I think I've got just one more question. Yeah, let's go ahead and take a break.

(Short recess.)

BY MS. ARNOLD:

Q. Mr. Hoff, turning to page 61, please, of your testimony. At lines 11 and 12, you're discussing the 100 percent ratchet mechanism in Schedule 49, and you say that it provides a substantial incentive for customers to reduce winter peak loads. Would you explain that?

A. Well, I tried to explain it in the testimony, but basically what a ratchet does is makes

you pay -- makes you pay 12 times whatever the peak period is, the peak load is for that peak hour, essentially. That's a very substantial cost, if you will, and if you had set that peak in the summertime, or a period outside of when the ratchet is in effect, you only pay one month's time to set that cost, and the example I give here, say you have $2.80 demand charge, and you set it during the winter period, that is your peak. Year round you have to pay 12 times that $2.80, so it costs you actually $33.60. In essence you're paying $33.60 and then all the rest of your demands are free for the rest of the year, because they're not up to that peak hour through the definition of peak.

If on the other hand you had set that at the summertime, you only pay that $2.80 for one month because it's not ratcheted for the 12-month period, and so the relative cost of setting a peak demand in summer versus winter is dramatically different than Schedule 49. In one case you say you have to pay it for that month plus another 11 months, but if you set it in the summertime, you only have to pay it for that month.

Q. So you're saying that setting the demand -- setting the minimum in the winter is the sensitive

for reducing the peak load in the winter?

A. Yes.

Q. Because that ratchets it down for the rest of the year, is that what you're saying?

A. Having the ratchet period set in the summer then is an incentive to try to keep that demand off the winter, in the winter period.

Q. Why is it that Schedule 31 has only a 60 percent ratchet?

A. It's because when -- I wasn't involved when they actually implemented this ratcheting, but they felt that the magnitude of that differential -- it's fairly severe, and I guess they wanted to mitigate the effects of it.

Q. On the next page, on page 62, in the top question, you talk about the allocation of PRAM revenues, and you say that the company proposes to allocate the PRAM revenues as was approved in the decoupling proceeding which I understand is, in other words, you're going to allocate the PRAM revenues in the manner approved by the Commission in the '89 rate case or '88 rate case.

A. No, the PRAM case is ~~U-89811-T~~ UE-901183-T alh.

Q. I know that, but doesn't the decoupling proceeding say that the PRAM revenues would be

allocated as they were in the '88 rate case?

A. It's used -- this is a little bit confusing. It uses factors that come from the '88 case, so that's what's the basis of the '88 case. The '90 proceeding established a way of allocating the PRAM revenues that picks up factors that were determined in the '88 case, so, you know, it does tie to both of those orders essentially.

Q. Well, if there is an order in this case, in the rate design case, why would those factors be used to allocate the PRAM revenues?

A. When I say that, though, done in a manner similar to the way we're doing it, what I mean is that this case will establish those new factors. These are allocation factors for demand and energy and those sorts of things. We would use -- if we had another general rate case, we would use those factors to allocate PRAM in the future, but not until we have another general rate case.

Q. That's my question. Assuming that an order comes out of the rate design case prior to an order in the next general rate case, which might not be until 1994, why not use the allocation factors that are approved in this case to allocate --

A. We're not asking for approval of any

allocation factors. All the factors that we're using go back to that original case.

Q. Okay. That's all my questions.

A. Thank you.

E X A M I N A T I O N

BY MR. ADAMS:

Q. Good afternoon, Mr. Hoff. I'm going to ask you sort of a bunch of questions because some of them have already been covered by other parties here. First off, I want to start off with a question that was deferred to you. Referring to Exhibit 5, do you have Ms. Lynch's exhibits?

A. Yes.

Q. Pages one and two, could you explain what discount rate was used and if it's not the net of tax cost of capital, explain why that discount rate was used?

A. Okay. First of all I think it helps to go to WICFUR 305 because that explains most of this stuff, and WICFUR 305 after the first two pages, you'll see a page that is basically this document. Then the next page talks about where we get some of the assumptions.

Q. Could you slow down a moment?

A. Yeah.

Q. Okay. Go ahead.

A. So now we're on 305.

Q. Page --

A. And let's look at page three and you'll see that that's the same as CEL page one, or Exhibit 5, page one, and then page two was the same as Exhibit 5, page two.

Q. Wait, wait, wait, wait. When you say page numbers, there's a page up on the top and there's a page number at the bottom. Which one are we talking about?

A. Yeah, I'm sorry. Where it says on the top WICFUR 305, page three.

Q. Okay.

A. That is CEL -- that is Exhibit 5, page one.

Q. Okay.

A. I'm just tying it in so that -- and then the next page is Exhibit 5, page two. Okay?

Q. Yes.

A. So this basically is the basis for this, and then this exhibit, this data request tries to explain all of the points, and if you look at the next page, which is WICFUR 305, page five, attachment one, this is out of our least cost plan, integrated

resource plan, 92, 93, it's appendix E, page five. In that -- that shows two of the basic -- several of the basic assumptions. If you look at resource number three, and you read across there, it's a combustion turbine combined cycle cogen, capacity factor of 80 percent, capital costs of $670 a kilowatt, and fixed charge rate of 13.2 percent.

Q. Yes.

A. Okay. Then you go down with the asterisks and the fixed charge rate and it defines what we use in that fixed charge rate, and so that's a fixed charge rate and then if you want to have some further discussions or further explanation of that, in the integrated resource plan on pages -- again, this is in the appendixes, appendix H, page 20, you'll see a -- there's a 30-year -- under -- oh, you don't have that, I don't think, but you'll be able to find that there's a 13.16 levelizing rate that is used on a 30-year. They be on page H-21, you'll find some depreciation information, and on page H-22, you'll find the weighted costs of capital at 10.41, which is what was used in that case in the medium scenario.

Q. So what's the discount rate?

A. 10.41.

Q. So am I correct that it's not a net of tax

cost of capital?

A. I always get confused what net of tax really means. It does include the effect of property -- of federal income taxes.

Q. You say it does include, does or does not?

A. Well, according to the footnote, the fixed charge rate, which is consistent with that rate, equals the present value of the fixed costs of an asset, depreciation or amortized, cost of money, property tax, federal income taxes and insurance, so supposedly that includes federal income tax, so unless I -- I believe it includes federal income tax.

Q. Does that include the effect of the deductibility of those taxes, those federal income taxes?

A. Effect of the deductibility? Actually I'm not sure. I think not, but I'm not sure.

Q. Can we just leave it at the status of the record that it does not, but if you are able to check and find it does in fact, it's the opposite, if you'd let us know?

A. Yes.

Q. Let's turn to your testimony for a moment, page three, and I wanted to ask you a similar question to one we asked Mr. Knutsen. You list five factors

there at the bottom of page five over to the top of -- excuse me, the bottom of page three over to the top of page four.

A. This is Mr. Knutsen's testimony?

Q. No, this is your testimony, T-8.

A. Oh, okay.

Q. And are those five factors that you list, are those listed in the order of importance?

A. No.

Q. Are you able to tell us what kind of weight you gave to those various factors in terms of priority?

A. No. Just tried to balance them without assigning weight, I probably ended up in my own mind assigning some weight somehow, but tried to balance them without assigning weight.

Q. So at least you consciously didn't give any particular weights to given categories?

A. That's correct.

Q. How did you decide how far to move rates for each class, for each class towards the results of your cost of service study?

A. It was in the interest of -- you know, you're balancing here trying to move to what you believe is right with the interest of gradualism and,

you know, we talked a little bit about the economic effects these changes might have on companies and those sorts of things. It's purely a judgment call that says that I don't want to go 100 percent, I certainly don't want to go zero percent, so I'll pick a third.

Q. Apparently you made the decision though also that that one-third ought to apply to all schedules that needed changes rather than individual schedules?

A. In the general categories, yes.

Q. Did you consider either differential growth rates between classes or differential risks of different classes in your rate spread proposals?

A. No, I did not.

Q. If you would look at page 19, lines ten through 14, dealing with residential rates, there you indicate that space heat customers do not need a marginal cost price signal. Do you see that?

A. Yes.

Q. Do you agree that space heat usage has a lower load factor and therefore a higher cost to serve KWH than residential water heat or appliance usage?

A. Yes.

Q. But it is your position that six cents is

enough at that price these customers have all the incentive they need to either participate in weatherization programs or switch to gas?

A. I think that the decision is a little bit broader than just that they have enough, you know, incentive they need. I do think that, for instance, with the relationship to gas, the magnitude of that differential is so great, that adding even another penny to the price of electricity is probably just overkill because there's already a big differential. I think what I was basically trying to look at -- well, plus we have our conservation programs that are pretty well subscribed and we don't need additional incentive there, and what I was really looking at is what is most of the usage, and most of the usage either is water heat or looks like water heat, and of course everything is at the margin. It's not just the biggest stuff that's at the margin, everything is at the margin. Over 80 percent of our customers have water heat. A lot of the other loads look a lot like water heat so it made a lot more sense to target something that looked like at the water heat load than at the space heat load.

Q. Did Puget consider requiring customers who participate in weatherization and then switch fuels to

repay a portion of their grant?

A. Actually I think that part of our contract that we have with the customers does require them to pay if they do it within a certain time period, but that was not a rate design consideration. To me that's more of a -- you know, the conservation program type consideration.

Q. So that's not part of any proposal made in this proceeding?

A. That's not part of the proposal here, no.

Q. Could you update us on the status of the incandescent and mercury vapor street lighting programs? I believe that the company indicated in the collaborative that it would finish converting these incandescent lights -- and mercury vapor lighting, to convert them rather than have a penalty rate applied to those customers.

A. It's my understanding as far as the company program that we're on track to have that done by the end of the year, that I was just informed a while ago that that is moving and on a track to be done by the end of the year.

Q. So basically then the company doesn't view there's any need for a rate design to address that issue, is that correct?

A. That's correct.

Q. I want to just sort of ask some very general questions. Throughout the questioning today, I think the terms "forward looking" and "marginal costs" have been used, and frankly I've gotten very confused as to what it is we're talking about when we're using those terms. Also there's the company's avoided cost filing that it currently has in effect. What -- which one of these terms are you using in designing your rates, and at what level are you using it? What is the dollar or cents per kilowatt hour rate that you are using?

A. Okay. I think we used all three terms various ways. Maybe I can help try to define a little bit. Marginal cost is a theoretical concept so it doesn't really have an actual value, and when you start assigning it a value then it generally becomes something else. So I would say marginal cost, when I'm talking about marginal cost, I am talking about a theoretical concept in the manner that Kahn does when I quote him in the testimony, as the cost of the incremental unit, the last unit. So to translate that to specifics, I have used the avoided cost filing to establish the tail block of the residential rate and of the two optional rates of primary and high voltage.

So that marginal cost, if you will, is actually the avoided cost filing for those at certain -- with certain assumptions made.

Q. Could you give us the rates? I mean, is this by way of the most current in effect?

A. Yeah, those rates -- well, it's interesting because the rate -- like the residential rate itself is not the marginal cost rate itself because it's -- we wanted the marginal cost to be what that avoided cost is net of the other two riders. There's the schedule 100 PRAM rider and there's the Schedule 94 residential exchange rider and so the rate itself that we're charging is the rate that's the tail block rate that's the summer rate and the winter rate and is 5.535 cents per kilowatt hour in the summertime and 6.096 cents per kilowatt hour in the wintertime. Now, again, that's not exactly the marginal cost and if I could find the right --

Q. While you're looking, Mr. Hoff, is that a 12-year rate?

A. That essentially is the levelized 12-year -- what it is is the avoided costs for a load that is similar to a residential water heat load for 12 years. What I'm looking for is something that -- there is a data request that actually specifies -- shows the

calculation of that and shows how it is net of those other two. This would be in Record Request No. 6 from staff.

Q. You used record request but this is staff data request.

A. I'm sorry. No. 6 from staff, and you'll see -- well, you don't need to have it in front of you, but basically that shows that the winter avoided cost from the calculation that I said is 5.7496, from that you subtract the PRAM one rate of .2508, add Schedule 94 rate of .5700 ~~6494.57~~ to get what the actual rate is of 6.0688, so the avoided cost for this residential water heat customer is 5.7496 in wintertime and 5.2038 in the summertime.

Q. Looking at that data request, under the categories winter energy and summer energy, are those figures, the data -- are those the avoided cost the company has filed?

A. Yes.

Q. Okay.

A. No, excuse me. Did you say avoided costs it's filed?

Q. Yes.

A. These were adjusted because of the change in the peak credit method to reflect the change of 17

percent of the cost being demand instead of 20 percent. The avoided cost filing was based on assumption that 80 percent of these costs would be energy and 20 percent demand, so we took that same basic information and reran it with a peak credit of 17/83, so it's the same basic information with that one change in assumption.

Q. Are there any transmission or distribution costs reflected in those numbers?

A. No.

Q. How about transmission or distribution losses, are they reflected in those numbers? If you want to go off the record and just get an answer, feel free.

A. Okay. Just a second. Is it yes? We've got an answer. Yes.

Q. Could you please then provide the work papers that reflect those calculations?

A. Sure.

Q. I guess that would be Deposition Request 6. If you have a broader work paper that reflects all of that, that's fine, too. I didn't know what you specifically had.

A. Okay.

(Deposition Request No. 6.)

Q. Mr. Hoff, you talked -- you gave us these costs in respect to the residential rate design. Were these avoided costs used for any other -- calculation of any of the other rate schedules?

A. They're used in a general sense to -- they were used to establish the energy differential of 10 percent, and so in that aspect, information from this is used in all the other schedules, all the other energy schedules, because they all have a ten percent differential.

Q. That's just the winter, summer differential?

A. Right.

Q. Okay.

A. Then this information was also used to establish the tail block of the optional rates for the primary and high voltage optional rate.

Q. I believe that there was some questioning earlier that indicated that actually some of the resources, the newly acquired resources actually has come in below your avoided cost figures, correct?

A. That's what Mr. Knutsen said.

Q. Right. But, in other words, you applied your straight filed avoided cost figures?

A. Yeah, we did not adjust it at all for

that.

Q. Now, were these avoided costs also used as part of the peak credit method, methodology that you have applied here?

A. They weren't used directly. The resources that -- there was a combined cycle CT that is the resource of the third stage of this avoided cost filing. There's a combined cycle CT that's used in the calculation of the peak credit method, so they're related, but they're not exactly the same number.

Q. Why would you have different numbers if you used combined cycle CT in both instances? Why wouldn't you have --

A. Well, maybe I misspoke. I think as far as the -- see, the CT was -- that we used in the peak credit was out of the integrated resource plan. I believe that that's the same costs that they used in the -- in the avoided cost filing, but since -- I'm not exactly sure of that because power supply does that calculation and they have that -- I know that avoided cost filing is part of this other process. We went specifically into the least cost plan to pick out the price of the CT. As far as I know, they're at least consistent if not identical.

Q. Again, let us assume that in fact they are

the same numbers but if you are able to check and find out they are not, please notify us.

A. Okay.

Q. Moving to another area, there's been quite a bit of discussion concerning Schedule 29 and 35, and I want to sort of step back from the rate design process for a moment and ask you a couple of questions that relate to those schedules in the current PRAM. Am I correct that as the PRAM is currently filed, there would be no additional costs put on Schedule 29?

A. That's correct.

Q. What about Schedule 35?

A. Same.

Q. And could you give us the reason why that is?

A. Well, it's because there wasn't any increase allocated to that in the last general rate case. When we went into PRAM, we looked at the allocation factors, picked them up out of that case. There was a zero allocation factor and so we applied it. When we applied that process, they didn't get any change, and so it's sort of a mechanical reason that they didn't get it, because they didn't have any increase out of the '88 case.

Q. But in terms of the rationale for the

increase in the PRAM, those schedules should reflect the same increases as all the other schedules, shouldn't they?

A. That's why we're proposing to change that in this case, so that -- what I'm talking about in this case about the effects of future PRAMs and how we would propose to change, that one of the changes is we would put this cost back in to apply this to all the schedules and not leave out irrigation.

Q. This is a suggestion how to deal with Schedules 29 and 35 in the context of the PRAM in the rate design proceeding?

A. Yeah. At the end of my testimony, there is a brief discussion about -- I guess I'd better turn to mine. Page 62. Allocation of PRAM revenues, and it was sort of meant to be a general discussion -- you know, I think we think that the allocation of PRAM revenues is a part of this case, it's appropriately part of this case, not of the existing PRAM revenues, but the PRAM revenues that would come after the next general case or -- and we felt that we should address that. In our look at it, we thought that the existing allocation of those revenues was okay with the exception of irrigation customers should get an increase to those, and then also the allocation of the

increase to the residential sector should go first to the tail block, if there is a new marginal cost, until it goes to the marginal cost, and then gets spread also there.

Q. Am I correct then that the company at this juncture does not intend to, if you will, amend or whatever the word is, their current PRAM figures so that those customer classes receive a portion of the increase that the company is currently requesting in the PRAM?

A. That's correct. That's not part of the PRAM case. It's part of this case.

Q. If we look at a scenario where the company does not file a general rate case this year, and so we have another year, probably '94, before the results of the general rate case are in, what recommendation in terms of the application of the PRAM three would you be making in this case, because we may have two years before we look at the whole issue of a general rate case and the interrelationships with the PRAM?

A. Well, you know, I suppose there's a possibility that this case could reach some conclusions prior to our filing PRAM three next summer, and if it did, we could include a change to the methodology of allocating the PRAM revenues in

that PRAM filing, which, you know, we decided not to file a general rate case and so it was another year and we didn't want to wait that long to do this. But if this case was on its existing track which would have an order -- could have an order in March of this year, we could have something that then would tell us what to do in the PRAM filing for the allocation of the PRAM revenues, which then would be filed in June or effective in October.

Q. I was thinking more in terms of those two schedules, 29 and 35 as opposed to necessarily all of the results of the rate design case.

A. Uh-huh. Right. Well, I mean, the Commission could order us to do -- whenever it got an order, it could order us to implement it. That order could be implemented, in my mind, when we file the PRAM or even before we actually get the PRAM order if they wanted to.

Q. Okay. Could you update us briefly on what the changes from the existing to the proposed rate design is for each of those two schedules, that is, Schedules 29 and 35? What are the specific changes that you are making to those two schedules?

A. Sure. You would see that as far as the rates go, and the easiest place would be to look in

the revised Exhibit 14, those pages 17 and 18, that I referred to earlier. Page 17 of -- are you there?

Q. Yes.

A. Okay. If you look on Schedule 29 -- oh, excuse me. That doesn't have the existing, does it.

Q. No. Take a look at page 14.

A. Okay. This would be a comparison. Thank you. Page 14 would have the present rates and the proposed rates and so you could look through there to see the differences. The magnitude of the differences is not very large.

Q. Well, am I correct -- referring now to Schedule 29, am I correct that there is a substantial increase to the winter demand charge?

A. Yes, that is correct.

Q. What portion of kilowatt hours that are sold under Schedule 29 occur in the winter?

A. Very small proportion.

Q. When you say very small, can you give me a closer number than that?

A. Will you give me a second?

Q. Sure. And could you tell me what document you're referring to?

A. These would be the rate design work papers which is not an exhibit but you probably have -- I

don't know if you have them in front of you, but basically --

Q. Probably not.

A. Okay. Let me do a quick calculation here. There is 5,018 kilowatts of demand in the wintertime, and 10,954 in the summer, was the Schedule 29.

Q. So you have about a third of your usage outside of your summer period?

A. It appears that way, yes.

Q. Okay. Going now to your summer rates, am I correct the demand charge pretty much stays the same, but there's a small increase in your energy charge for that schedule?

A. Yes, that's correct.

Q. How about for Schedule 35? I don't find that in here.

A. I don't find it in here, either. I can tell you what it is from some other -- if you would like, why don't you turn to Exhibit 14 again, on page 31 -- page 17 -- excuse me, page -- that's not there either. There it is.

Q. At the bottom of page 17?

A. Bottom of page 17, and I'll give you what the comparable rates were as far as what the existing rates are.

Q. Okay. By the way, when you say -- we're comparing them with the revised, correct, you're going to give us the current as compared with the revised?

A. Yeah. Well, I guess I won't either. Okay. So the revised demand charge on 35 is $105. Existing demand charge is $48.55.

Q. You're giving us the customer charge, is that correct?

A. Customer charge, right.

Q. Okay. $48?

A. And 55 cents.

Q. Okay.

A. The existing October to March kilowatt demand charge is $5.41 -- excuse me. The proposed is $5.41. The existing is $4.02. The April to September kilowatt demand charge is $1.56, as proposed. The current is the same, $1.56. The energy charge for October to March, all kilowatt hours proposed is 2.827 cents. The existing is 2.6198 cents per kilowatt hour, and the April to September energy charge proposed is 2.070 cents and existing is 2.1198 cents per kilowatt hour.

Q. So you've actually decreased the summer energy rate for that class, that customer group?

A. Yes.

Q. And you've left the demand for that same period, the summer period, the same?

A. Yes.

Q. So effectively that customer group is seeing a decrease in its summer rates which is the time most customers are on that system?

A. Except that the basic charge went from $48.55 to a dollar -- $105.

Q. That customer class also takes advantage of Bonneville credit, does it not?

A. Yes.

Q. You passed that through?

A. Yes.

Q. And that's true also for Schedule 29, is it not?

A. Correct.

Q. Okay. Do you know the amount of that credit currently?

A. No, I don't.

Q. To speed it along, maybe you could just provide it to us.

A. Sure.

Q. As a deposition request.

A. So you want the amount of the credit and a kilowatt -- what it actually was last year or on a

rate basis?

Q. When you say last year, there's one currently in effect for the summer months, I believe.

A. Just what the rate is. Sure. I'll get that.

Q. I don't know whether that's the same for the two schedules or not, but --

A. We'll provide it for both.

Q. And could we also as part of that, and if you can direct me to a work paper or something that has that information on it, I'd like to see usage for each one of those classes that is Schedule 21 and 35 by month.

A. Usage by month?

Q. By month.

A. For the whole class?

Q. Yes.

A. I'd have to get that. That's not in the work papers.

Q. If you could just make that all part of Deposition Request 7.

A. Okay.

(Deposition Request No. 7.)

Q. Are you up with me and I'll shift gears on you?

A. Well, I don't know if I'm up with you shifting gears, but --

Q. Okay. Would you refer to your schedule -- excuse me, your Exhibit 12, Schedule 6? This is the residential interruptible water heat credit. And if you'd look under availability at the number two, says service under this schedule allows for interruption of a customer's hot water heating equipment rated at 7600 water or greater.

A. Yes.

Q. Is that number a typographical error?

A. I don't think so.

Q. Or phrased a different way, would any of your residential customers qualify at that level?

A. I hope so. It's meant to be the combined -- it's meant to be a normal water heater, not an all-in-sink-erator ~~incinerator~~ type water heater and those types of things. If somehow we've messed this up, it's supposed to be the combined wattage, not just the wattage that's on when the -- I mean, most of these things have two elements and only one of the elements can actually be on, it's the wattage of both of those elements, not just one of them.

Q. That was our concern, if the normal residential water heater I think would be around 3800

-- two 3800 watt elements.

A. Right.

Q. Of which only one could be on at a time, and the way that tariff is written, it would appear that there might be a confusion as to, you know, what the qualifying level was, and do I gather that you really are talking in terms of someone who has a double 3800 watt element water heater would be eligible, is that correct?

A. Would be eligible, and if that's not clear enough, if you want to suggest something or make it clearer, we'll be glad to change that.

Q. We just want to be sure we were on the same understanding of what it was intended to address.

A. Right.

Q. Would you now look at Schedule 43, Primary Schools. Again, holding your hand there, but also looking at your revised -- I think it's your Exhibit 14, is that correct, DWH 7, page 18?

A. Okay.

Q. Now, am I correct that you're actually lowering the demand charge, the winter demand charge for that group of customers?

A. I have it as an increase of the demand charge for wintertime and a lowering for summertime.

Q. Compared first of all to your filed and revised, you've lowered it, correct?

A. That's probably -- yes, we did. Oh.

Q. Well, there appear to be several things going on which we want to ask you about. It appears that you've lowered the winter, and basically eliminated seasonality, so that your winter and summer demand charges are the same.

A. Yes.

Q. Was that your intent?

A. Yeah, I think what we did with that schedule, because we are also closing it out, is we just kept it basically consistent with the existing schedule which doesn't have any differential, so instead of trying to apply a differential to it, we just kept the existing one.

Q. What is the current demand for winter --

A. $3.16 per kilowatt.

Q. For both summer and winter?

A. For both summer and winter, correct.

Q. So are you saying there is a small increase in that one?

A. Just a small increase, that's correct.

Q. And there is no winter differential currently and there's no winter differential in the

demand charge proposed, is that correct?

A. That's correct.

Q. What is the current energy charge for summer and winter?

A. The current energy charge for October through March is 2.8840 per kilowatt hour.

Q. I'm sorry, again, 2.8 --

A. 8840.

Q. Okay.

A. And summer is 2.7467.

Q. So you were lowering the energy charge for both seasons to that customer group as well?

A. That's correct. The overall increase to the class -- to that schedule was the same as the rest of the prime areas, which was like less than 2 percent. We had a fairly significant increase in the basic charge. It went from 63.50 to $105. Then we wanted to increase the demand charge and what was left over was the energy charge which then went down.

Q. Now, did I understand you to say that you have frozen that schedule?

A. Yes.

Q. Now, when you say freeze that particular schedule, that means any particular customer who was on that schedule can remain on that schedule, what,

for as long as that customer continues to take power?

A. Until we change the schedule.

Q. Am I correct that at least looking at Exhibit 4, page three, that the rate of return under your cost study, or that particular category, is the lowest rate of return for any customer group? It's shown as 1.1 percent.

A. That's ~~where~~ WHY we want to eliminate the schedule.

Q. But you're not eliminating it, but you --

A. That's correct. And that is under the philosophy of, you know, not making dramatic changes and, you know, these schools have been schools for a long time and have sort of counted on this, and to dramatically change their schedules on them would have an impact that I'm not sure we all want them to have.

Q. Would it be a fair statement to say that part of the reason that they're getting this treatment is because they're schools?

A. Yes.

Q. Going back to the revised Exhibit 12, page 18? There is a schedule that's new to us. Go ahead and let me know when you've got that page.

MR. TROTTER: I think you've got the wrong exhibit.

MR. ADAMS: 14, I'm sorry.

MR. TROTTER: Page 18?

MR. ADAMS: Yes, the last page of the revised.

BY MR. ADAMS:

Q. Okay. Between Schedule 43 which you were just referring to and Schedule 46, high voltage general, there's a category called primary general service schedule 001. What is that schedule?

A. Says, "City of Sumas has a long-term contract with us, a 20 year contract."

Q. This is a municipal utility, is that correct?

A. Yeah, I'm not sure. It's not a resale type arrangement. It's for -- I'm not sure exactly the details of it, but it's just one contract that's part of the schedule.

Q. And can you give us a little background on that schedule? How long has it existed or how long has the contract been in effect?

A. No, I can't. I could provide it to you.

Q. Okay. If you could provide us the information -- before we go to that status, is this contract being changed? In other words, are there any rates being changed as to this contract?

A. The rate in the contract is being changed, yes.

Q. And that's pursuant to the cost of service study or to the terms of the contract?

A. I mean, I think that the terms of the contract -- well, let me check. Just a second. Yeah. They allow us to make changes in the rate. It's just that it's under a special schedule and we can still make changes to the rate.

Q. The question comes to mind and again maybe this is something you can't answer currently, but why on earth are they not buying as a preference customer from Bonneville at a lower rate?

A. I really don't know.

Q. Could we provide that as deposition request number eight, a copy of the contract and, you know, basically a brief narrative of the history of this contract?

A. Sure.

(Deposition Request No. 8.)

Q. Would you look at your Exhibit 13? Looking down the column one at the costs that are basically demand costs at lines 12 through 17, are the calculations of demand cost shown here based on embedded costs or are they forward-looking costs?

A. Well, the demand costs -- these come from the cost of service model, so that it's whatever the allocators are used there. Of course, the peak credit method is used to allocate production costs. The peak credit method is forward looking, so therefore I guess the costs resulting from that would be forward looking. There are other demand costs that are not involved with peak credit method that are probably not forward looking. It's really a cost of service question.

Q. Would you not agree that the vast majority of the demand costs are not involved in the peak credit methodology?

A. I don't know if it's the vast majority. There are a lot of other costs that are not involved with peak credit.

Q. The transmission and distribution costs are not included, are they?

A. The generation related transmission are. The non-generation related and distribution are not.

Q. Am I not correct that these demand costs shown here are embedded costs?

A. Well, again, the total costs are all embedded costs. The allocation of the costs between demand and energy, et cetera, to the extent that they

use this forward looking allocation factor would not be, in my mind, embedded in the same sense. We're getting a problem of semantics I think here.

Q. Am I correct that these costs shown here are the basis for the proposed increases to Schedules 31 and 49 for the demand charges 31 and 49, and the decrease to the Schedule 31 energy charges?

A. Yes. It's these costs that I used to calculate demand charges -- changes, and then, you know, what's left over has to be -- affect the energy, so, yes, I think that's true.

Q. In your response to this and perhaps to changes in other areas where they relate to your demand charges, do you start with your demand costs and then use energy charges as the residual?

A. That's correct, and we have demand and customer because there's three components, the demand and then the basic charge and then the energy as a residual.

Q. So you do demand first and then you take out customer and then you're left with the residual, is that correct?

A. Yes.

Q. Thanks. That's all I have.

MR. TROTTER: That's it.

MR. VAN NOSTRAND: No redirect.

(Deposition concluded at 4:00 p.m.)

C E R T I F I C A T E

As Court Reporter, I hereby certify that the foregoing transcript is true and accurate and contains all the facts, matters, and proceedings of the hearing held on: 8-13-92

Marilyn Hohman

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