ORIGINAL TRANSCRIPT

SALT LAKE CITY INTEGRATED PROJECTS FIRM POWER RATES

CRSP TRANSMISSION AND ANCILLARY SERVICE RATES

PUBLIC INFORMATION FORUM

February 5, 2008 * 1:30 p.m.

Location: Radisson Hotel
2177 West North Temple
Salt Lake City, Utah 84116

Participants: Adam Arellano, Attorney; Carol Loftin, Rates Manager; Rodney Bailey, Public Utilities Specialist; Paul Stuart, Public Utilities Specialist; and Tamala Gheller, Rates Technician.

Reporter: Ashley Davis, RPR
Notary Public in and for the State of Utah

CITICOURT
THE REPORTING GROUP
170 South Main Street, Suite 300
Salt Lake City, Utah 84101
PH: 801.532.3441 FAX: 801.532.3414 TOLL FREE: 877.532.3441

P R O C E E D I N G S

MR. ARELLANO: Good afternoon, everybody. First off, I'd like to welcome everybody to today's Public Information Forum.

My name is Adam Arellano, and I am an attorney with the Office of General Counsel for the Western Area Power Administration in Lakewood, Colorado; and I will be moderating today's Public Information Forum.

As noticed in the January 4th, 2008 Federal Register, Volume 73, Number 3, page 858, this Public Information Forum has been scheduled so that we have the opportunity to give you a full explanation of the proposed adjustments to the rates for Salt Lake City area integrated projects for power and for the Colorado River storage project transmission and ancillary services.

The proposed adjustments to these rates are scheduled to be effective on October 1st, 2008. You may wish to refer to the rate brochure, which was mailed to interested parties on January 11, 2008. This forum will also give you the opportunity to ask any questions that you might have regarding the rate adjustment process.

Please keep in mind that all issues raised today should be relevant to the proposed rate adjustment process, and please wait to ask any questions until after the formal presentation is completed.

A public comment forum for this proposed rate adjustment is scheduled to be held at the same location on March 4, 2008, beginning at 1:30 p.m.

Now I'd like to give you a little overview of today's information forum. Ms. Carol Loftin, Rates Manager in Western's Colorado River Storage Project Management Center here in Salt Lake City, will give some introductory remarks, and then a presentation on the rate process.

Joining Ms. Loftin will be Mr. Paul Stuart, Ms. Tamala Gheller, and Mr. Rodney Bailey.

Following our presentation, we will take questions from the public which may arise from this presentation or which you may generally have regarding the allocation process. I will moderate the question and answer process -- or I'm sorry. I will monitor the question and answer session.

Please be aware that a verbatim transcript of today's forum is being prepared by the court reporter. Everything said while we are in the session today, including the questions and answers, together with any exhibits will be a part of the official record. And copies of today's transcript will be available to anybody who wants a copy upon payment and requested fee to the court reporter.

The court reporter's name, address and telephone number may be attained at any time after today's forum. Copies of the transcript and the complete record of this public process will also be available for review at the Colorado River Storage Project Management Center in Salt Lake City.

When we get to the question and answer period, if you -- when we get to the question and answer period, if you raise your hand, I will recognize you. And after I recognize you, please state your full name. And you may want to spell your last name and also identify any party that you are representing today.

After the presentation, if you could provide a business card to the court reporter, that would be appreciated; and also, please speak up.

Lastly, all questions should be relevant to the proposed rate adjustments. As moderator, I reserve the right to disallow any question which is not relevant to today's forum. It is also possible that some of our staff will have questions based on the questions you ask, so just keep that in mind.

And with that, I'll turn it over to Carol.

MS. LOFTIN: Thank you, Adam. Before I get started, for those of you that wanted to access the Internet from here, the access code is 6LR9Y6. So that's 6LR9Y6.

Again, I want to welcome you today. I hope you find this presentation informative. Most of this is not data that you have not seen before. It may be updated in some fashion or form, but it shouldn't have any surprises in here for you today.

As mentioned by Adam, this is a Public Information Forum, and the statements made here today are being recorded. The discussion that we have here is mostly from the rate brochure that was mailed out to you on January 11th. Also, as Adam discussed, we would like to hold your questions and comments until after our presentation. That will enable us to move along a little bit quicker.

We have three main topics here to discuss: The rate schedule process, and then a discussion on the Salt Lake City Integrated Projects Firm Power Rate Adjustment, and also the CRSP transmission and ancillary services along with that.

When we talk about the Salt Lake City integrated project rate adjustment, we'll be showing you the current power repayment study, a comparison of existing and proposed rates, and the cost recovery charge.

When we discuss the CRSP transmission and ancillary services, we'll again talk about the standard rates that we have in place today, the point-to-point network firm, nonfirm, and the ancillary services that go along with the transmission provider.

First of all, the rate schedule. As you know, we had -- the federal register notice was published on January 4th, 2008, and here we are today. I hope it's February 5th, or maybe I'm at the wrong meeting. Maybe I want to be. But I think it is February 5th, and we are here for the Public Information Forum.

About a month from now, we'll meet back in this room, same time, same place, at 1:30 to have the public comment forum. The close of the comment and consultation period ends April 3rd, 2008, and our proposed proposal is to have all of our rates effective October 1st, 2008.

Just a little background for those of you that are new to some of these rate processes. I put together a slide that shows you what the duration has been for the rate adjustment processes. And as you can see, the duration runs anywhere from 54 months to ten months. Our current rate will be in effect for three years at the end of this fiscal year.

So this is pretty much consistent with what you have seen the last three or four rate processes.

The proposed Salt Lake City integrated project firm power rate includes, like it is currently done, a firm power rate and a cost-recovery charge. The firm power rate is designed to recover all of our operation, maintenance, and replacement expenses, our interest, principal payment, irrigation aid, again, same as the current rate. And also this time, we are still including the CRC, or the cost recovery charge, that we implemented the last rate process.

And as you are aware, this is mainly used during financial hardships to help us recover our purchase power costs. Again, our proposal is to have all of these rates effective April 1st, 2008.

Just to show you a little picture of what your firm power bill will still continue to look like, of course we have your capacity charge, your energy charge; and then the CRC, if needed, will be added to that energy rate for a total monthly charge.

I'd now like to have Paul come up and give you more specifics on the firm power rate.

MR. STUART: Okay. I see that quite a few of you have heard my spiel before, so I hope maybe you'll get maybe something out of it, you'll learn a little bit that you already didn't know. Otherwise, maybe we could have one of you come up and take this part.

First of all, I hope I can see my notes here. First of all, I'd like to talk just briefly about the Salt Lake City area integrated projects, which is the rate we're talking about for its firm power. It consists of five projects.

One very large project is CRSP, or Colorado River Storage Project, and four smaller ones. To show you -- give you an idea of the magnitude here, this is the percent of energy that we accrued in the fiscal year 2006 from each of these projects. So CRSP in '06 had about 97 percent of the energy. The other projects was around 1 percent each.

Each of these projects have to stand

financially on its own. It has to pay its own costs, make its own repayment and so forth. But in 1987, they were integrated together for rate-making purposes, and now -- so their resources sold as one block of energy.

So we have Collbran and Rio Grande, Collbran being the Western Colorado; Rio Grande down in New Mexico; Seedskadee, Wyoming; Dolores, in Colorado. And, of course, the CRSP mainstem units are the units of the CRSP which includes Glen Canyon, Flaming Gorge, Navajo and Aspinall Units.

Okay. I want to talk just a little bit now about the power repayment study itself, because it's the power repayment study that we use to determine what our rate should be. The power repayment study is prepared each year for each project.

It documents the historical financial data for each of these projects, it provides the status of repayment for each of these projects, and it also projects revenue requirements and the rate needed for each of these projects individually. But for the SLIP rate, we combine them all into one for what we call a SLIP PRS.

Like I said, the SLIP PRS summarizes

historical data and calculates payment for each power system. It estimates future revenue requirements and computes power rates also for each system. The SLIP rate for the SLIP -- I'll be talking mostly about the CRSP, since it's the lion's share of the resource.

Every year in the spring, as soon as we receive the budgets, we do what we call a preliminary study. We put all the projections into the power repayment study, and that determines what the rate picture looks like. We sort of take a rate -- a snapshot in time to see if the rate that we currently have is sufficient to meet the revenue requirements out into the future.

And then for the past several years, we've been having a meeting in June with customers to give them an idea of what this preliminary power repayment study is indicating at the time; and we did that last June. Then at the end of each year, we do a -- we do a final power repayment study when we get the final fiscal year data.

And we're in the process right now of assembling the final data for '07. The study we'll be looking at today is a preliminary '07, but we plan on having the latest data in the power repayment study for the rate order.

As many of you know, the power repayment study is a spreadsheet analysis in Excel format. This is an example of -- a very simplified example of the summary that's produced by the power repayment study. The -- this is the executive summary.

Each row represents a year, and each column represents a revenue and expense category or a repayment category. A PRS shows historic and estimated future amounts in columns. The future is based on budgets and projected sales.

So we have the power sales, then we have the revenues and expenses and what's available for repayment. And then over to the right of the spreadsheet summary, we have the investments and repayment on those investments. And the methodology we use is to repay highest interest-bearing investments first.

Now, if you would pull out your power repayment study executive summary, which was a handout, I'll just go over that briefly to give you an idea of what -- what we're talking about here.

This is the executive summary of the SLIP power repayment study, and you'll see that the rows going down the left-hand side of the spreadsheet indicate the year, the fiscal year. And for this power repayment study, which starts in 1963, corresponding with the CRSP project, goes through the last historic year of 2007.

Like I mentioned, we don't have the 2007 data yet, but we will put it in as soon as we get it. Then we have a historical subtotal. And then on down through the spreadsheet, we go into the future years of the study.

Now, this power repayment study goes through 2065 to cover a period of time that we're required to have investments repaid, which is around 2060. So that's the years.

Now, going across the columns here, the first column is the total revenue. It's a lump sum of all the revenue that we receive from the project. And then the next several columns indicate the various types of expenses that occur, operation and maintenance, some reimbursable environmental costs that we would include here, purchase power, transmission service, the transmission that we've paid to use.

Now, the next column, which is column G, you see it's "Integrated Projects Requirements." Now, this is where we put -- we assemble all of the revenue requirements of the four smaller projects into one column in the SLIP study. And so that's all of the revenue requirements of the smaller projects.

Then we have a category called "Other Miscellaneous Costs," and then "Interest," and then "Total Expenses." Then as we work our way across, we have a summary of adjustments, revenue after annual expenses, which is what is available for repayment, and then we start the repayment going across.

Now, the first set of four columns is "Deficits." If we have deficits to repay, that's where we show how that'll be paid off.

Then the next set of four is "Replacements," and you have to go over to the next sheet to see where that continues. So that next set of investments is "Replacements," and then the next is "Original Projects and Additions." So the original project costs and any additions to project costs that have occurred since the beginning of the project would go in those columns.

The last two sets of four are "Aid to Irrigation," which is the response that CRSP has according to the CRSP Act to pay for the irrigation allocation of the CRSP mainstem storage units. And then the last four is what we call "Aid to Participating Projects."

The CRSP Act provided for several subprojects, if you will, of the CRSP, such as Dolores, Seedskadee, Animas-La Plata, and various others that have irrigation purposes. And in these projects, they have actually -- actually have irrigators that are irrigating land.

And there's analyses that are done in these projects to indicate what the irrigator's ability to repay is, and what is over and above that is paid by power. So that's where that obligation fits into the summary.

You'll see that in column AA, there's an item called "Surplus M&I Revenue." Now, this is a -- sort of a type of revenue that comes in kind of in the back door of the PRS to reduce the power's responsibility to pay for aid to irrigation and aid to participating projects. So that surplus M&I goes to pay for first aid to irrigation and then aid to participating projects at the beginning of it.

Okay. Now, you'll notice that in the future years of lines there, in rows 55 through 59, we've kind of colored it yellow there. That's just to kind of indicate that's the budget years that we're looking at. And, of course, the year that we're in, 2008; and then the 2009 through 2007 is the -- is from our 2009 work program review or work program budget.

Then we continue on with the green color through the year 2025. That's to indicate that both the yellow and the green period is the period of time that we look at to determine what the rate needs to be to recover our revenue requirements, or it's called the rate-setting period.

So that's just to give you an idea of what's in the power repayment study.

Okay. Now, I think, as I mentioned earlier, the power repayment study has two purposes: One, to establish repayment for capital costs, and the other is to compute rates. It's interesting to note that as far as status of repayment goes, this is what we show as of the end of 2006. And when we finally get our 2007 data, we'll update this shortly.

But you can see that Collbran -- actually, three -- three of the projects are basically paid off: Collbran, Rio Grande, and Seedskadee. They have no more investments to be repaid -- no more power investments. Let me indicate that it's power investment up here. Rio Grande and Collbran have a small irrigation obligation repayment as well.

CRSP, the mainstem units, is about

two-thirds paid off as of 2006. Rio Grande, you see there is an amount there to pay. That Rio Grande -- actually, the project began in 1940, so it's our oldest project; and it's been paid off for a while.

But just recently, there were some additions that were made, some enhancements that were made to the project, and some replacements that, as of '06, remain to be paid off. So it has a balance there now. Dolores is our newest project, comes on in 1994, and so it's just getting started. And it's 10 percent paid.

Okay. Now, I'd like to show this table here, and I'd like to briefly go over, using this table, how our rates are computed in the power repayment study. This is a simple example of the existing rate that we have now.

But first, at the top there, it shows a rate-setting period for our current rate. Our rate began in 2006, fiscal year 2006; and of course our pinchpoint year is 2025. The pinchpoint year is the year of the rate-setting period or the year of repayment when the highest amount of revenue requirement comes due. And this happens in 2025 in our SLIP study. So we have 20 years to look at revenue requirements in the future.

So our revenue requirements consist of our annual expenses, expenses that have to be paid each year, such as interest and operation and maintenance and so forth, and then our principal payments that we would be required to pay during that same period. So then we have our total revenue requirements. In this case, it's about $165 million. Now, these are an average per year; so for the 20-year period, the revenue requirements are $165 million per year.

Now, the next line down there says: "Offsetting Annual Revenue." What this is is revenue that comes into the SLIP projects that's related to such things as transmission, ancillary services that's not a part of the firm power rate.

And so it's an offset. It actually reduces the amount of revenue requirement that firm power users have to pay. That happens to be, in this case, $35 million. So we reduced 165 by 35, and our net annual revenue requirement for our existing rate is 130 million.

Okay. So then -- that's our annual revenue requirement for the 20-year period. So in order to raise that money, we apply that to the energy and capacity that we -- that we provide to the customers. And, again, we use averages for the energy and capacity sales, and here we have 5 million megawatt hours of energy and a million kilowatts of capacity that we base our billing rates on.

Now, you'll hear "billing rates," you'll hear "composite rate." The composite rate is the net energy requirements divided by the total energy that we sell. The composite rate is used for comparison purposes. We don't bill using that.

The billing rates are -- we take the net annual revenue requirements, we allocate a portion to capacity and a portion to energy, roughly half and half, and then we take the rate denominator, which would be the energy and capacity amounts that we are selling over that period of time, and that's how we come up with the current rate, which is 10.43 mills per kilowatt-hour for energy and $4.43 kilowatts per month for capacity.

Now, so now you know all about rate making. What we want to do now is to say, "Well, that's our current rate." Now, what is happened is -- in the last three years that would change things? So now we've taken another picture, another snapshot. We take another look at what's going on in the future with revenue requirements and see how it stacks up with our current rates.

So the next thing I want you to pull out is your -- this comparison table. It's not on a slide yet, but if you look at the comparison table handout, I'll just go through that briefly; and then we'll go down through it a section at a time and explain it in a little more detail.

This is similar to the example table we just went over, but it has a little bit more detail in it as far as expenses and repayment goes, and then it has a "Change" column over in the right-hand side that shows you what has changed since the current rate.

The current rate is the green band, the green column. The preliminary 2007 PRS is shown in white. And so then the difference or the change from the current to the preliminary 2007 PRS is shown in the yellow, both in the actual magnitude and in the percent change.

So what we'll be doing, then, is going down through this table to see what is changed in terms of annual revenue requirements, expenses, principal payments, offsetting revenues, energy and capacity sales, and, of course, at the bottom, the rates. So we'll just take some time now and go down through this piecemeal.

First of all, we'll talk about the top part of the table, which has to do with the rate-setting period. And the pinchpoint, as we now see things, is the same. It stays the same as it was in the current rate at 2025; but now we've rolled three years ahead, so our number of years that we're looking at now is 17 rather than 20.

Okay. Now let's look at the annual revenue requirements and go down to the O&M and so forth.

Before we go too far, I want to just emphasize that these data, the 2007 PRS, using the '09 work plan, has the preliminary 2007 data; and we will be looking at the final data as its -- as it comes in. We don't expect to -- a significant change from what we had projected to what is going to occur. We see a little bit of increase in purchase power, maybe about $5 million for '07, but we don't expect a whole lot of change. But we will look at it and use the latest data.

Okay. So operation and maintenance costs increased by about 9 percent over the three-year period. It increased from 5.4 million in the 2006 work plan to -- they increased 5.4 million from the 2006 work plan to the 2009 work plan. If you break it out between the generation of transmission agencies, the Bureau's -- Western increased by about 2.2 million or about 6 percent, and the Bureau's increased about 3.2 million or about 12 percent.

Now, Western's increase was mostly attributable to cost of living indexing. Reclamation's increase of 12 percent, most of that 8 percent was due to the inclusion of security costs. Now, some of you heard a lot about the security costs at the mainstem facilities. We did not include those -- we only included a small amount of security costs in the current rate. So that's the biggest jump in the Bureau's cost there.

The remainder of their costs, similar to Western's, was attributable to cost of living indexing. Purchase power expense projections increased about $3.2 million per year. In the current rate PRS in 2006 through 2009, median hydrology was used. After that, $2 million per year was included for administrative merchant function activities.

In the proposed rate PRS, median hydrology was used through 2014. After that, $4 million per year was included for administrative merchant function activities.

I'm going to talk a little bit more about purchase power in the next slide, but I want to cover a few more of these items on this slide before we go there.

The transmission costs really change very little, so we don't need to talk about that. The integrated project requirement, as I mentioned a little bit ago, is the requirement for the four smaller projects. They increase slightly, about 4 percent, and that was mostly due to -- again, to increases in cost of living indexing and that kind of thing.

The interest costs, you see here, increased, mostly because the repayment that we had projected in our current rate PRS didn't materialize due to higher-than-expected purchase power costs caused mostly by dry weather conditions, the drought that we've been in for several years.

This greater amount of unpaid power investment accrued greater than projected interest costs and, of course, less than projected repayment. And we'll see in a minute how that affected the repayment amounts, the required repayment amounts.

"Other Costs" down there, you see other costs actually decreased by almost a million dollars.

That's mostly salinity costs, which projections have decreased in recent years by -- by about 900 -- well, actually, the salinity costs decreased by about 800,000, mostly due to budget reductions in USDA programs. So that's good news.

Now, let's talk a little bit more about purchase power. This slide shows in a bar graph a comparison between what we had projected in our current rate that we put together three years ago versus what has either actually happened in blue or what we now project will happen in green.

So white is what we had projected, but blue for '05 and '06 is what actually happened. So you can see that we under-projected in '05 and really under-projected in '06. Now, '07, we don't have the final data; but preliminary indication is that '07 is going to be about $45 million purchase power, so we'll be up here.

Then as we projected the future, we -- this shows how our purchase power costs have increased.

Okay. Now I'm going to talk about principal payments. And as I was sort of indicating a little earlier, because of -- because of the drought and increased purchases, we didn't get the repayment done that we thought we would with the current rate, starting three years ago. So we still have to pay it off.

So now we've -- we're paying almost the same amounts off but in fewer years. So, for example, replacement, we paid -- well, let me just indicate here replacement payments increased about 1.2 million per year. This was mostly because the three years since the current rate has been in effect -- since that time, only 25 million of the expected 76 million was or is now expected to be made.

For original project and additions, a similar thing occurred with this. Only 25 million of the 47 million of payments expected with the current rate are now expected to be made. So of course they'll all be made, but now they have to be made in a shorter period of time; so that increase the amount per year that's required.

Now, on the irrigation, the total aid to irrigation payments in both PRSs are expected -- are not expected to be made until after 2013. So now that repayment period is three years shorter, the average amount per year that would be required increases by about a million dollars per year. And this is the sum of the two types of irrigation, this amount here.

The aid to participating projects, similar to irrigation, payments are not made on any specific projects until 2016. Again, however, because of the three-year shorter rate-setting period, the amounts per year increase about $5 million in the comparison table.

So that's how you get the $9 million increase and principal payments that would be required for us now.

The next slide is kind of an interesting slide to show. The total irrigation obligations for aid to irrigation and aid to participating projects is shown here. We get these data from the Bureau of Reclamation each year.

You can see the aid to mainstem irrigation went up about a million dollars a year. That changes -- usually every year changes slightly, mostly due to some -- the M and I sales, the contracts that they have in place, and so forth, which goes to pay also for aid to mainstem. So as it changes and it's adjusted, the power's obligation also changes.

The aid to participating projects actually went down. Mostly went down because there are some projects that are still being built, such as the Animas-La Plata Unit; and as these are being built and costs and allocations are adjusted and updated, the allocations to irrigation change from year to year.

Okay. This slide shows for the 20 -- for the 17-year rate-setting period, the timing of the various revenue requirements. You see that, working up from the bottom, this is the timing and the mix of the various revenue requirements through the rate-setting period.

The bottom two layers are O&M integrated projects, and they stay fairly constant through the rate-setting period. The next layer is purchase power and wheeling, the yellow. Now, this goes down gradually through 2014. As I mentioned, we -- at 2014 we basically chop off purchases down to the $4 million amount that we would need for administrative purposes. So that's why the yellow declined.

The next year is interest, which decreases as interest-bearing investment is repaid. So our interest, it goes -- tails off to almost zero. The purple is replacement repayment, which varies from year to year. It can be up or down, depending on the interest rate. The highest-interest bearing paid first, and then some replacements because of a short service life are required to be paid off, you know, before investment. So it varies from year to year through the whole study.

Back toward the end, actually, when everything else is paid off, most of the investments are paid in the year that they occur. So they're almost like they're expensed.

So as power repayment is paid, replacements are also -- okay. Let me -- the salmon-colored layer is power repayment. So this one is power repayment. You can see it's paid off in about 2020, the power investment. The dark blue -- is that what that is? That is aid to irrigation, 111 million that we owe there. It is paid -- actually totally paid off at about 2021, thereabouts.

So we have this large area of light blue that continues out there. The obligations due at 2025 for aid to participating projects create what is called the rate-setting pinchpoint or the PRS. And as I said earlier, it's when the largest amount of revenue requirement during the repayment period comes due.

Now, all of the repayment obligation for aid to participating projects is not paid off by 2025. There is still amounts remaining to be paid. But 2025 is the pinchpoint, and so we've limited this graph to just the pinchpoint year, since it's -- going out to 2060 would be fairly detailed. But that wouldn't be a bad thing to look at, too.

Okay. So let's look at offsetting revenue now. This went down, as I mentioned, about $899,000 per year. Firm transmission revenue is based on existing contracts, and nonfirm revenue is based on a five-year historical average. Firm transmission was up $1.4 million from the current rate, nonfirm was down about $2.8 million per year.

The merchant function revenue is based on a five-year historical average, and it went down about 800,000. Resale energy was down about 1.7 million, and transaction fee revenue was up about 900,000. Other revenue also based on a five-year historical average includes ancillary services, such as facility-use charges, spinning reserve, and other miscellaneous charges; and they were up $1.4 million per year.

So the bottom line there shows that the net annual revenue requirements went up about

15 percent. Offsetting revenue decreased by about 900,000. The net annual revenue requirements, as I said, went up $18.9 million or about -- yeah, or about 15 percent there, as the bottom line indicates.

Okay. So what about our sales? Energy and capacity sales, it changed. The energy sales went up from 5,153,000 megawatt hours to 5,170,000 megawatt hours, or about 17,000 megawatt hours. Not a lot of -- not a big change, but some change. And I'll explain that in a minute why that went up, because here capacity sales actually went down from 1 million 448 kilowatts to 1 million 434. So they went down.

And I'm going to -- well, I'll just mention here that energy sales, back when we -- well, let's go to the next slide and come back to this one. This is what happened. Well, in 2004, we started to ramp up. We decreased our SHP service and with agreement that we ramp up to 2009. Well, this ramp-up process creates a -- creates a certain average here.

And then the way we're seeing it right now, we lop off these years, and so we have a ramped-up year. So our average is actually higher on average than it was in our current rate.

And then as you can see also here, the project use, as you compare project use from our current rate to the preliminary '07, you can see that they -- that they went down in most years. And the reason that they went down is due to reductions in needs for project use, particularly from the Navajo paradox, Bonneville and Animas-La Plata and those projects. So that's why they went down.

Now, let's flip back up just for a sec. So that's why these changed. So anyway, these are the rates that we're looking at here, going from the energy rate of 10.43 to 11.95, which is an increase of about 1.52 mills per kilowatt-hour, about 15 percent, and a capacity from $4.43 per kilowatt per month to $5.08 per kilowatt per month, also about a 15 percent increase.

The last slide I want to show is a pie chart, just to show you the relative importance of the various elements of the revenue requirements. As you can see, the O&M costs are the highest, 38 percent; irrigation is next at 20 percent. And then we have, probably -- then replacements, projects and additions, purchase power and wheeling, integrated projects, and interest.

So this is the components of our 2009

proposed firm power rate of 28.85 mills per kilowatt-hour.

Now I'd like to introduce Tamala Gheller, and she's going to be talking to us about the cost recovery charge.

MS. GHELLER: Thanks, Paul.

First, I will begin by explaining the CRC and its purpose. Since the CRC is based on estimates, it will need to be calculated. This is what a prior-year adjustment does. For further details on how these two are calculated, you can look at the SLIP-F9 rate schedule and our rate brochure.

This CRC will be charged to all customers unless they choose to take less energy than their SHP or waive the CRC. We will calculate a waiver level point by determining the funds available for purchase power without having an adverse effect on the basin fund. Purchases above this waiver level will trigger the CRC.

The main purposes of the CRC are to: One, maintain a minimum balance in the basin fund of no less than $20 million; two, to ensure the basin fund is not depleted by more than 25 percent each year; and three, is used to help pay for purchase power costs above what the basin fund can sustain.

The CRC will only be applied when there is a possible financial hardship on the basin fund. The CRC, when applied, will be added to the firm power energy rate. Since the balance in the basin fund is at a level where we do not anticipate the need for a CRC at this time, the '09 projection for the CRC is still at zero.

New to this rate adjustment process is a shortage criteria trigger and is in addition to the CRC. If Reclamation's 24-month study projects that Glen Canyon Dam water releases will drop below 8.23 million acre feet in a water year, which is October through September, Western will recalculate the CRC to include those lower estimates of hydropower generation and the estimated costs for the additional purchase power necessary.

Western will give the customers a 45-day notice to request a waiver of the CRC, which is the same length of time as it is in the initial schedule. This recalculation will remain in effect for the remainder of the current fiscal year or until the water release is returned to the above 8.23 million acre feet. Then it would be recalculated again.

Since the CRC will be based on projections, we will have to calculate an estimate to actual adjustment at the end of each year. Please refer to the rates brochure also in the rate schedule SLIP-F9 for further details of the calculations.

Since we have not had to implement the CRC, we haven't had to make this adjustment to the power bills. This is a schedule of the calculation of the CRC: May 1st, using the April 24-month study, we will have the CRC calculated and give notice to the customers requesting a response by the 15th of June.

The CRC calculation will become effective on October 1st, which is the beginning of the new fiscal year. All this is true, of course, unless we have to rerun the CRC because the shortage criteria trigger is used.

I'll now turn it over to Rodney.

MR. BAILEY: Today I'm going to talk about the proposed transmission and ancillary services rates.

The current rate formula became effective October 1st, 2002. It was extended in 2007 and will expire September 30, 2010. The CRSP MC is seeking continued approval of the rate formulas for calculation of transmission services. It is a formula-based rate and is recalculated annually using the most recent year's historical data. Notification of annual rate changes are sent in August of each year.

The formula determines a percentage of transmission investments to total CRSP investments. A fixed charge percentage of O&M, interest and depreciation expense to net transmission investment cost is determined. This fixed charge percentage is applied to the net transmission investment cost to determine the annual transmission revenue requirements.

Transmission revenue credits are then subtracted, and the -- these revenue credits are things like short-term, point-to-point sales, ancillary services, and other miscellaneous revenues. The transmission system total load consists of firm power and firm transmission contracts.

So the formula, then, is the annual transmission revenue requirements minus the transmission revenue credits, and this equals the net annual transmission revenue requirements. The net annual transmission revenue requirements are then divided by transmission system total load, and this gives us the rate.

This is a listing of the historical

transmission rates since we began using the fixed rate methodology in 2002.

The rate for nonfirm point-to-point transmission is based on the current CRSP point-to-point transmission rate, expressed in mills per kilowatt-hour. And the current -- current fiscal year 2008 rate is 3.03 mills per kilowatt-hour.

The network transmission service charge will be the product of the network customers' load ratio times one-twelfth of the total annual transmission revenue requirement.

The network customer load ratio share is the hourly load coincident with the CRSP transmission system monthly peak, and that's the -- that's the formula there. The charge is equal to the load ratio times the net annual transmission revenue requirements, divided by 12.

For the ancillary services, six ancillary services will continue to be offered. They are: Scheduling, system control and dispatch; reactive supply and voltage control; regulation and frequency control; energy imbalance; spinning reserves and supplemental reserves.

At the bottom of this slide is a website that links to Western's tariff, and in Western's tariff it defines these ancillary services.

Now I'll talk about scheduling, system control, and dispatch. And this is defined on a Schedule 1 of Western's tariff. It is included in the firm power and transmission rates. And at this time, we are proposing no change to what is within the current rate for this service.

Defined under Schedule 2 of Western's tariff is "Reactive supply and voltage control." And this is provided by the WACM and WALC control areas and their respective rates. Again, there is no change in the proposed rate to the current methodology at this service as well.

Regulation and frequency control is defined under Schedule 3 of Western's tariff. If resources are available, it can be provided by the CRSP. It will be charged at the firm power rate; otherwise, the WACM and WALC control area can provide the service of -- at their respective rates. There's no change to the proposed rate for this methodology as well.

Energy imbalance is defined under Schedule 4 of Western's tariff, and this is provided to WACM and WALC control areas. Again, no change is proposed for this methodology.

Spinning and supplemental reserves are defined under Schedule 5 and 6 of Western's tariff. If these services are provided by Western, the rate under the Western system's power full contract will apply. No change, again, is proposed for this rate methodology.

Okay. And finally, here are the contacts at Western; our names, phone numbers, and e-mail addresses. And of particular importance is a website that will have documentation for the rate process, and then as this one -- this website up here -- and then we also have an e-mail address that we would request that you send your comments or questions to that e-mail address.

You can still reach us by these addresses, but we would prefer that you send them to the rate adjustment address for any comments or questions.

And I will now turn the time back over to Adam to moderate your questions that you might have.

MR. ARELLANO: Thank you. And with that, we will take questions, and not everybody at once, please.

MR. WONER: My name is Jeff Woner, W-o-n-e-r, and I'm with CREDA, C-r-e-d-a.

I noticed in your purchase power

projections in the previous rates study, you only forecasted out five years; and in this one you're going out six. And then in addition to that, you're increasing even further on yours by 2 million.

Can you just talk about the reason for that?

MS. LOFTIN: Yes, I will. Pertaining to your first question, going out five -- this year is going to five. That is an error and we will fix that. It should be five years. I'm going to cap to the first five years, and then after it goes to $4 million.

As far as changing from the 2 million to 4 million, we went back and looked at our operation cost to just maintain our system at a higher load, and those numbers were looking more like 4 million rather than the 2 million.

MR. WONER: Okay. And then I guess just another question along those same lines: We've seen some e-mails recently about turbine runner replacements increasing efficiency. Have those been factored into these new numbers?

MS. LOFTIN: No, those have not been factored in. It's my understanding that a group is looking into those factors, but we don't have an answer for you on that yet.

MR. ARELLANO: Thank you. Any other questions?

MS. JAMES: Leslie James with CREDA.

You may have said this and I may have missed it, but which month's 24-month study is currently utilized in this table?

MS. LOFTIN: It's quite confusing, so hang with me. There's actually several things going on.

I assume that you're really talking about what -- what 24-month study was used to determine our purchase power.

MS. JAMES: Right.

MS. LOFTIN: For the first fiscal year out, it's fiscal year '08, the first three years we used the Bureau's August -- three months we used the Bureau's August -- it was the Bureau's August 24-month study. And then for the remainder of that '08, we used the Bureau's long-term medium-hydrology study, until we got to 2014, which will be 2014, and then that will be reduced down to the 4 million.

Does that make sense what I'm saying? Okay. A little bit of a hodge-podge there. And I can reiterate that as soon as I find my notes to make sure I said that right.

Yes, the August 24-month study for '07 for October, November, December, and the remaining of '08 and through 2014, the Bureau's long-term hydrology. After that, 2014 on, would be the 4 million.

MS. JAMES: Okay. I guess --

MS. LOFTIN: Just to show operation costs.

MS. JAMES: -- just a follow-up question, then, to that. Will you be updating before you finalize this rate process with a more current 24-month study, given the improvement in hydrology work, as optimistic?

MS. LOFTIN: We can. What happens -- as you know, we're down to -- in previous rate analyses, we've always, for the long term, used the Bureau's long-term hydro study out through 2060.

And because last time we changed that process a little bit where we looked at the first five future years out, then drop it down to the operation cost, it doesn't become as important to use the Bureau's long-term study or the most current 24-month study. But yes, we will do that when it's current; but it doesn't have as great an impact on it as it used to.

MS. JAMES: Another question. Paul, I

think, mentioned that a significant amount of the Bureau's increase in O&M is due to the inclusion of security costs.

What level is being included -- what -- I don't know how I'm trying to ask this, because yesterday the President's budget came out, and it has a certain level of security costs in it. And there's also legislation that has now moved through the House that capped the level of security costs.

So what's in the current plan here?

MS. LOFTIN: Well, as you're aware, Leslie, we can't put any numbers in that isn't by law. So what we've left in is what the Bureau has currently given us.

We're hoping that when the Bureau provides us those updated numbers and how legislation is passed, that we will update those numbers as they come to be. But right now, it's -- I think it's an average of about $2 million per year in the study at this point.

MS. JAMES: Okay. And I guess just on the other questions, we'll just wait and --

MS. LOFTIN: Sure.

MS. JAMES: -- you guys will respond back?

MS. LOFTIN: Yeah.

And we were hoping that we would have somebody from the Bureau of Reclamation here to help us answer some of these questions, and I don't see anybody here. So we apologize for that as well.

MS. JAMES: Well, we had several related to cost allocations and/or reallocations; and I believe there's some language in the budget, based on a quick look I had yesterday on the Bureau's budget, that may or may not relate to that that I think could, again, have an optimistic impact on this.

Also, the project-use requirement, we had a question on what causes it to increase in 2021. And I think the other -- oh, the status of Glen Canyon cost allocation study. So --

MS. LOFTIN: Yeah. We have our ideas and our suggestions on that, but perhaps it's best for the Bureau to help us answer those questions. So we'll get back with you on this.

Which reminds me, again, as these questions come up, as you write to the CRSP rate adjustment e-mail address, we will be posting those questions and responses on our website, so you can follow right along as it happens. We hope this helps keep everybody engaged with the rate process better than we have been able to in the past.

MS. JAMES: Do you want me, then, to send the questions I had into that particular website?

MS. LOFTIN: Yeah. That's CRSPMSadj@wapa.gov.

MR. WONER: One last question on your transmission rates, either for Rodney or Jeff.

Do you have on/off and seasonal nonfirm rates on your transmission? When you sell it, is it just at the -- I know you said you had a cap. I've seen sort of a trend go to almost an hourly price with on being higher than off.

MR. ACKERMAN: I'm not familiar with the transmission side of the house anymore because of merchant -- split between merchant and transmission, so I'm not real familiar with how they're doing that.

MS. LOFTIN: Good answer, Jeff. I appreciate that. We're showing standard of conduct right there.

And as you know, 890 came out with the conditional firm; and I'm kind of guessing that you may be looking into that. We have not done that rate now. We are kind of holding back to let operation side of the house kind of go through 890 and see what they're going to do before we implement that unconditional.

However, we do offer nonfirm on a short-term basis, which usually is -- or firm on a short-term basis, which usually is a nonfirm rate or firm rate once it's negotiated.

MR. ARELLANO: Any other questions?

MS. JAMES: I guess just one more procedural or for timingwise, when do you guys plan to make any revisions to either reflect your work plans or any of these other items, and will that be before the comment forum or will it be after the comment forum and before the close of the comment period?

MS. LOFTIN: That's always a hard one to answer because, you know, it's the -- I almost said it's the tail chasing the dog; but, actually, it's the dog chasing the tail.

But anyway, as Paul mentioned, as soon as we get final audits and 2007 numbers, we will put those in. We don't expect much change, except we did notice that our purchase power costs are probably about $5 million higher than what we have in the power repayment study.

You're probably more familiar with the work program review budget process than I am. As you know, we're going have a meeting at the end of

February, I believe. Once we feel like we have the solid numbers for 2010, we'll be putting those in. When that falls out, we're hoping that it falls out before the end of the consultation and comment period, which is April 3rd.

But if there is some significant changes, we'll certainly extend that period to give you a chance to comment on those before we close the comment consultation, which, I think, is what you really wanted me to say after all those words.

MS. JAMES: Right.

MR. ARELLANO: All right. Any other questions?

MR. RAMPTON: Ted Rampton with UAMPS.

Slide 35 talks about ancillary services. I'm just wondering, is there any requirements for systems to use those services, such that do they have to be interconnected with Western or could they be outside of Western's control area?

MS. LOFTIN: Do you have one in particular that you're thinking about to help me answer that question?

MR. RAMPTON: Yeah, reactive supply, regulation, balance, all of them.

MS. LOFTIN: It depends. Under the --

under your firm power contact, we supply all these services for you. They're embedded in the firm power rate. Our ancillary services are usually applied to third-party customers that use that, and they are all available. If we can't supply them through Jeff's group, then we look to WACM and WALC system to help supply that.

MR. RAMPTON: So just a follow-up, if you want to use the scheduling system control of dispatch, you need to be --

MS. LOFTIN: We'll help you out with that, yes.

MR. RAMPTON: Even though you're not our listed system?

MS. LOFTIN: I believe so.

MR. RAMPTON: Okay.

MS. LOFTIN: We can follow up to make sure, but I'm sure we can do something on that.

MR. RAMPTON: One other question. In way of process, in the event that the hydrology improves drastically, is there a -- some kind of mechanism that will compensate for that?

MS. LOFTIN: If the hydrology improves drastically, you will have less purchase power costs in your rate -- built in your rate -- or, for example, I think in 2008 we have about $35 million projected. And maybe if that goes down to 30, say, that additional 5 million would go towards repayment. So it would help speed up our repayment.

And as you heard Paul talk, we have made literally zero or very little towards project repayment since the last time we went through rate process. So each time, we're kind of sliding and making the project repayment a little bit higher.

So to answer your question, it will probably go towards project repayment.

MR. ARELLANO: Anybody else? All right. Well, with that, I want to --

MR. WONER: Sorry. I have one more question.

We submitted a comment or I guess a question and asked that you look at a stepped rate that -- and I was just wondering if you've given any more thought to that.

In other words, rather than giving us a 14 percent increase right off the bat, 7 the first year and then another 7 the next year -- is there any more thought to that?

MS. LOFTIN: We're certainly open to the idea. We haven't run any numbers or calculations on that, but we're certainly open to looking into that idea.

MR. ARELLANO: Any other questions?

Now I'd like to thank you for coming out and listening to our presentation and thank you for your questions. But I would like to reiterate that -- or just make it clear that we have -- that you will have various opportunities to provide comments -- or to provide formal comments.

Written comments on this proposed rate adjustment may be submitted any time in the comment period, and written comments should be sent to Mr. Bradley Warren, who is the CRSP manager at the CRSP Management Center. We are listed at 150 Social Hall Avenue, Suite 300, Salt Lake City, Utah, 84111-1580.

E-mail comments should be sent to CRSPMCadj@wapa.gov, and any written comments should be mailed so that they arrive by April 3rd, 2008.

Further information may also be obtained from Ms. Loftin by either contacting her at the same address as Mr. Warren or calling (801) 524-6380, and you can e-mail her at LoftinC@wapa.gov. And you can also get further information by periodically going to Western's website. Our URL is posted up here. That is wapa.gov/crsp/ratescrsp/default.htm.

After the close of the comment period, Western representatives will review all the information that we've acquired. That includes the comment and the exhibits. And we will then announce our decision in the Federal Register Notice after the close of the comment period.

Comments -- the comments that were made during this public process will be discussed in that announcement.

And I would like to thank you all for coming today. And I would like to ask that if you haven't done so already, to sign in before you leave. And we will be around for a few minutes after this meeting if you have any informal questions that you would like to ask.

Thank you.

(Meeting was concluded at 2:45 p.m.)

REPORTER'S HEARING CERTIFICATE

STATE OF UTAH)
) ss.
COUNTY OF SALT LAKE)

I, Ashley Davis, Registered Professional Reporter and Notary Public in and for the State of Utah, do hereby certify:

That said proceeding was taken down by me in stenotype on February 5, 2008, at the place therein named, and was thereafter transcribed, and that a true and correct transcription of said testimony is set forth in the preceding pages;

I further certify that I am not kin or otherwise associated with any of the parties to said cause of action and that I am not interested in the outcome thereof.

WITNESS MY HAND AND OFFICIAL SEAL this 9th day of February, 2008.

Ashley Davis, RPR
Notary Public
Residing in Davis County

Notary Public
ASHLEY DAVIS
1105 North 1100 West
Farmington, Utah 84025
My Commission Expires
March 05, 2011
State of Utah

Western Area Power Administration
CRSP Management Center
SLCA/IP Firm Power CRSP Transmission and Ancillary Service Rates
Public Information Forum
Radisson Hotel Salt Lake City Airport
February 5, 2008
Attendees

	Name	Company	Phone #	E-mail
1	Leslie James	CREDA	602-748-1344	creda@qwest.net
2	Jeff Worner	CREDA	480-610-8741	jjwglkrs-live.com
3	Carol Loftin	WAPA	801-524-6380	loftinc@wapa.gov
4	Tamala Gheller	WAPA	801-524-6388	gheller@wapa.gov
5	Frances Hamada	WAPA	801-524-6379	hamada@wapa.gov
6	Cliff Barrett	CREDA	435 882 0774	[illegible]
7	Kevin Robison	MT. WHEELER POWER	775-289-8981	mwpkevin@mwpower.net

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Attendees

	Name	Company	Phone #	E-mail
8	Phil Rice	Deseret Power	801-619-6505	philrice@deseretpower.com
9	Burt [illegible]	WAPA	801 524-[illegible]	
10	Rodney Bailey	WAPA	801-524-4007	
11	Paul Stuart	"	801-524-3526	Stuart@wapa.gov
12	Jeff Ackerman	WAPA	970 2406209	ackerman@wapa.gov
13	Dan Stireman	Murray City Power	801-264-2706	dstireman@murray.utah.gov
14	Dave Walker	WAPA	524-4446	walker@wapa.gov
15	Ted Rampton	UAMPS	801-566-3938	ted@uamps.com

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SLCA/IP Firm Power CRSP Transmission and Ancillary Service Rates
Public Information Forum
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February 5, 2008
Attendees

	Name	Company	Phone #	E-mail
16	Allen Johnson	Bountiful City	801-298-6072	ajohnson @ bountifulutah.gov
17	Blaine Haacke	Murray City	801264-2715	bhaacke@murray.utah.gov
18	Leon Pexton	UMPA	801 798-7489	Lpexton @ umpa.cc
19				
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