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TRACK B RELIABILITY MUST RUN (RMR) WORKSHOP	DOCKET NO. E-00000D-03-0047 **STAFF'S NOTICE OF FILING TRANSCRIPT**

Staff of the Arizona Corporation Commission hereby files the transcript of the proceedings of the February 18, 2003 Track B Reliability Must Run (RMR) Workshop.

RESPECTFULLY SUBMITTED this 12th day of March, 2003.

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The original of the foregoing filed this 12th day of March, 2003, with:

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BEFORE THE ARIZONA CORPORATION COMMISSION

Track B Reliability Must Run (RMR) Workshop	) DOCKET NO.) E-00000D-03-0047)) SPECIAL OPEN MEETING

REPORTER'S TRANSCRIPT OF PROCEEDINGS

Phoenix, Arizona

February 18, 2003

ARIZONA REPORTING SERVICE, INC.
Court Reporting
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Phoenix, Arizona 85004-1103

By: CECELIA BROOKMAN, RPR
CCR NO. 50154

Prepared for:

ACC

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AGENDA

BE IT REMEMBERED that the above-entitled and numbered matter came on regularly to be heard before the Arizona Corporation Commission in Hearing Room 1 of said Commission, 1200 West Washington Street, Phoenix, Arizona, commencing at 9:10 a.m. on the 18th day of February, 2003.

BEFORE: MIKE GLEASON, Commissioner

APPEARANCES:

For the Commission Staff:

Jerry Smith
Prem Bahl

For TEP:

Ed Beck

For WAPA:

Jim Charters
Leonard York

For APS:

Cary Deise

CECELIA BROOKMAN
Certified Court Reporter
CCR No. 50154

MR. JERRY SMITH: Let's go on the record.

Good morning. Call this meeting to order. This is a reliability must-run workshop being held by the Arizona Corporation Commission. My name is Jerry Smith, Commission Staff member, and I will be facilitating the proceedings this morning.

As a result of this being noticed as an open meeting, we may have Commissioners attending off and on during this workshop. We also have our listen line open for those parties that will want to listen in on the proceedings.

We do have a court reporter this morning that will establish a record for us that will be filed in Docket No. E-00000D-03-0047. This is the docket number that has been opened to gather the 10-year plans filed in January of 2003, and January, 2004 for the use in the 2004 biennial transmission assessment.

We have today an agenda that has been noticed, if I can get our slide to advance here. We have five presentations of reliability must-run study reports this morning. We'll have one from TEP regarding the Tucson area. We have one regarding the river system, which is along the Colorado River from Lake Mead south to Yuma, that will be presented by Western Area Power Administration, and we have a report that has been submitted by Arizona Public Service Company that will be broken into two components. The first will look at the reliability must-run analysis for the Yuma area, and we will end with the bigger report of the reliability must-run analysis of the Phoenix area.

In order to give the proper orientation of these presentations this morning, I will be making a Staff presentation giving an overview of what the RMR study requirements were of the parties that are presenting the results of their studies today.

As we proceed through the agenda, we will have an opportunity for parties to ask questions and make comments. When you do so, I would ask you to please come to the microphone at the podium, give your name and who you represent, and speak distinctly so that the court reporter can capture that information for the record.

With that, I will commence our proceedings by commencing with Agenda Item No. 1.

I would like to begin this morning by giving you a procedural overview of how we got to this workshop today, and it has its origins back in the generic electric restructuring docket, Track A Decision No. 65152. And that decision required APS and Tucson Electric Power to work with Staff to develop an RMR study plan to file RMR studies by the end of last month, and again in January of 2004, and finally, to submit transmission plans that resolve the RMR concerns in the 2004 biennial transmission assessment report.

Then we had another proceeding involving the biennial transmission assessment for 2002. That decision number was 65476. And in that decision, the Commission approved a collaborative RMR study plan that was agreed to by all of the transmission providers in Arizona.

Finally, the third procedural framework for today's proceeding is again in the generic electric restructuring docket Track B. There is a proposed order and decision that will be addressed this Friday at an open meeting, and as part of that proposed order and decision is the requirement for Staff to update the contestable load in Exhibit B per the 2003-2005 RMR studies that we're going to be reviewing today.

To give you a better sense of what all of the words that I just cited for you really mean, let me give you sort of a procedural flow chart. By the Track A decision, we actually have two RMR studies that are occurring. We have the 2003-2005 studies that have just been filed that will be reviewed today, and then we have a year from now, January of 2004, we have an RMR study by the same parties that are to look at the whole 10-year period from 2004 to 2013. All of those results will go into the 2004 biennial transmission assessment.

Also, per the Track B proposed order, Staff has a requirement to update Exhibit B regarding the contestable load, and that will be accomplished by the presolicitation review date in the competitive solicitation process that is part of Track B. Since those proceedings will commence again on Friday the 21st, it is important that we get some clear understanding of what contestable load implications are as a result of RMR studies that will be reviewed today.

Let me take the burden off of the presenters this morning for each of the studies and give you some general definitions of how we have defined what a reliability must-run condition to be.

We do have geographic locations in this state where, when the load is above a certain load level, the transmission is constrained, and the hours that the load is above that transmission import capability is defined as an RMR condition.

If you look at the chart on the screen, we have a sinusoidal looking wave that represents the hourly load curve throughout an annual time period. And you'll see a dashed line that has the term SIL next to it. SIL stands for simultaneous import limit. This is the transmission import capability with no local generation in service. So for those hours that that load curve exceeds that SIL level, an RMR condition is defined as existing.

If you look at the peak local load and compare it to the SIL, the difference in those two numbers is what we're calling the RMR peak demand. This is the amount that we have been placing in the contestable load exhibit as RMR capacity.

And then if you look at the area under the curve that is above the SIL level and up to the local peak load, that area is what we are defining as the RMR energy.

One last line you'll see on this chart that you will hear some discussion of today is a line at the top that says MLSC. That stands for maximum load-serving capability, and this is the ability of the local system to serve load with both local generation and the import transmission serving that area.

It assumes that you have also made provisions for any local generation reserve requirements, and if there is a condition where the maximum load-serving capability is below the peak load for that local area, it would imply there's not adequate local generation or transmission, and it could imply for certain contingencies, there could be a load-shedding experience in that local system.

The RMR study plan that you will be hearing people respond to today was agreed to in the biennial transmission assessment, and approved by the decision of the Commission in the biennial transmission assessment. And that plan calls for six features to be provided in the RMR study efforts of the utilities.

The first is to define the annual SIL for each transmission import limited area. We'll review those for you today. It requires that a listing of all local generation and associated operational attributes be listed for those local units, that RMR conditions for each year of the 10-year plan be identified. Today we're only going to be looking at the time period 2003 to 2005. The 10-year period will be addressed next year in the report filed at that time.

The fourth requirement of the study plan is that a local generation sensitivity analysis be performed to look at to what degree various local generators mitigate the RMR condition so that we understand what is the minimum generation required locally, what combination of units, at what generation level will mitigate the RMR condition.

The fifth category of the study plan is to identify and study alternative solutions, and those solutions can be both transmission related elements being upgraded or added, or local generation solutions are also viewed as a reasonable alternative solution.

And finally, number six is to perform a comparative analysis and present worth analysis of alternative solutions.

If we go through this laundry list of six items in the study plan today for each of the reports that are going to be given, I think probably, given our focus on the Track B concern for contestable load, what I would suggest as possibly as a study score card for today, as each of the presenters come forward, that this might serve as a good sense of what the needs, how effectively the studies have answered questions for the Track B proceeding.

We have for the years 2003 through 2005 six different categories, local peak load, the SIL, the

RMR peak demand or capacity in megawatts, the RMR hours, or the hours that the RMR condition would exist in that local area, the RMR energy, that again being the energy above the SIL level to serve the load, and finally, minimum local generation required to mitigate the RMR condition.

With that, I will entertain any questions regarding the study requirements that we're going to be reviewing today, and if you have questions, please come to the podium and we'll take any of those questions.

(No response.)

MR. JERRY SMITH: Hearing none, I would suggest let's move on in our agenda, then, and I'm going to ask TEP to start with their presentation of the Tucson area. Mr. Ed Beck will make that presentation, and he will make it from this location.

MR. BECK: My name is Ed Beck. I'm supervisor of transmission planning for Tucson Electric Power, and I'm going to present the basic results of our RMR analysis.

First thing I want to make clear is that TEP operates its system to WECC NERC Level C criteria. We plan and operate to that. Whereas there is an indication in the biennial assessment that the RMR studies be done for N-1 conditions. That's the way we actually ran the RMR studies. We previously run and provided all the information on N-2 to the Commission in previous instances, and we were looking at this as a base condition for comparison purposes. So we did run it to N-1.

We looked out into the future three years, and each of those three years has various configuration changes on our system, and so each of those configurations does result in a different RMR level.

In 2003 TEP is adding a 500 kV intertie, it's the second parallel tie between TEP's system and APS' system. It's between APS' Saguaro substation, and TEP's Tortolita substation on the north portion of TEP's service territory.

In 2004, TEP is working with Southwest Transmission to add a new interconnection point to the east of TEP's service territory at a station called Winchester. And that will tie Southwest Transmission Company's system into TEP's Greenlee to Vail transmission line at the 345 kV level.

In the year 2005, we're looking to have an interconnection in place between TEP's South substation and a new substation at Nogales called

Gateway. That will interconnect TEP's service territory to Citizens', and also potentially in the future connect into CFE's system. That is pending a presidential permit process, so the CFE portion is less defined than our interconnection to Citizens.

In summary, these are the SIL values that TEP came up with for the three years. For 2003, we have a SIL of 1575, or an actual load on our system of 1606. Our critical outages are at the Springerville to Vail transmission line. The constraint is a var margin issue.

In 2004, our SIL goes up to 1750, with a system load of 1785. Again, that's limited by the Springerville to Vail line, var margin related. Again, in 2005, we have the similar critical outage by our SIL remains at 1750.

A summary of the SIL and the MLCS numbers that we came up with are shown in this table. In 2003, again we have the SIL at 1606. But our MLCS is 2371. TEP's peak load at that time is 1930. We have an RMR requirement of 337 megawatts. The annual cost for the local generation, the RMR generation is $146,000.

In 2004 our SIL is at 1785, our MLCS goes up to 2525, our peak load is projected to be 1996. We would be down to an RMR level of 163, and the cost of running that generation would be $31,000 incrementally.

In 2005, our SIL and MLCS stay the same. Our peak load increases to 2066, which results in an increase in the RMR to 341. The annual cost for that is $34,447. Locally, TEP has base-load units of approximately 450 megawatts, and we've got peaking units for 103 megawatts. Those are gas CTs. The RMR levels shown on the chart related to the number of hours in 2003. The number of hours were 337 hours. In 2004, it drops to 163. In 2005, we're back up to 341 hours?.

That's basically the results of our RMR study. Any questions?

COM. GLEASON: Yes. Commissioner Mike Gleason.

Do you run these around zero?

MR. BECK: We're already operating to the N-2 potential, so we operate them for planned N-2 situations.

COM. GLEASON: But you run it for N-1. My question was do you run it for N-0, your analysis?

MR. BECK: We would have the units on to the extent we're always anticipating an N-2 condition.

MR. JERRY SMITH: I believe the question is the Commissioner is asking -- this is Jerry Smith of Staff -- is, is the transmission limit for N-0 conditions available through your study effort, is it a number that is higher than your SIL or your --

MR. BECK: Definitely, yes. Under an N-0 condition, we have much greater import capability.

COM. GLEASON: Do you have the number?

MR. BECK: I can get that for you.

COM. GLEASON: Thank you.

MR. BECK: I don't have it up here, but I can get it for you, sure.

MR. JERRY SMITH: Mr. Beck, would that number be greater than your maximum load capacity?

MR. BECK: Yes. It's greater than our maximum load. Is that the question?

MR. JERRY SMITH: Maximum load-serving capability is -- let me back up.

Is the transmission import capability with an N-1 greater than your maximum load-serving capability, which is transmission import plus local generation?

MR. BECK: Can you run that by me again, please?

MR. JERRY SMITH: The maximum load-serving capability assumes that you have local generation at maximum output.

MR. BECK: Correct.

MR. JERRY SMITH: And it's based upon your contingency assessments?

MR. BECK: Right.

MR. JERRY SMITH: For no contingencies, would your transmission import capability likely be larger than the MLSC number?

MR. BECK: I believe it's pretty close. I don't know that it's much larger.

MR. JERRY SMITH: Anyone else with questions for TEP?

(No response.)

MR. JERRY SMITH: I have a couple from Staff that I would like to ask you. First in the area of modeling, you described three projects, improvements, transmission improvements, the second Saguaro/Tortolita tie in 2003, the Winchester project in 2004, and the Gateway transmission line in 2005.

We're also aware that there are some studies in progress looking at an interconnection of the Westwing/South line at Pinal. Is that interconnection possibly likely to occur in this 2003, 2005 time period? And secondly, if so, what impact would it have on these RMR conditions?

MR. BECK: We're looking at the potential to move the project. Right now the project is scheduled fpr 2006. We're looking at potentially moving that into the 2005 time frame. We did not study that as part of this RMR analysis, because we were not far enough along in our discussions to make sure that 2005 was the right time frame for the project to be in service.

We do expect that with that project, the RMR numbers will go down.

MR. JERRY SMITH: Secondly, you have described that your transmission import constraint is stability limited, and you have provided in your report, as part of your operating characteristics for your generating units what are labeled as Q max and Q min, which is the reactive power capability of your local units.

Do those quantities reflect that you are using automatic voltage regulators on all of these units such that the full range of those vars would be available to the system?

MR. BECK: Yes, they do.

MR. JERRY SMITH: Would you mind giving us a little tutorial for the benefit of studies to be reported behind you today that also will be stability, voltage stability, would you please describe how the reactive power capability is modeled and power flows relative to the machine characteristics, the var and megawatt machine characteristics?

MR. BECK: Actually, I probably would not be the best one to explain that.

MR. JERRY SMITH: I will leave that to another party, or if someone on your staff would be more suited, that's fine, too.

MR. BECK: We don't have the actual people running the programs here today with us, so maybe APS can help with that question.

MR. DEISE: We'll attempt to answer it, Jerry.

MR. BAHL: This is Prem Bahl with Staff. Ed, when you talk about var margin constraint, it seems to me that the condition, operating conditions would be under light year conditions, maybe in the winter and springtime.

MR. BECK: We have issues both in winter and summer.

MR. BAHL: In your general analysis you're taking peak load which occurs in summertime. In your var margin studies, you obviously are perhaps sort of taking the lower level, winter and spring; is that correct?

MR. BECK: Typically our major problems are in the summer, and we run our operating studies primarily for summer peak load issues. We do look at winter issues also, but they are typically not a limiting factor on our system.

MR. BAHL: When you state that, for example, here it's the var margin that is the constraint, what do we understand? The constraints in the summertime in that year, are they comparable, are they less severe or more? How do I compare the var margin constraint in terms of conditions at peak load in summer?

MR. BECK: As I stated, our typical limitations are in the summer at peak load. We haven't had problems, per se, in the wintertime, except for various -- there's certain outages that do cause issues, but...

MR. BAHL: Thank you.

MR. JERRY SMITH: Mr. Beck, in your report, you have reported the minimum generation required to serve peak load given the RMR conditions being voltage constraint. And if I understand those numbers correctly, I'm looking at your table at the bottom of Page 38, and top of Page 39 where you have for 2003, you have 35 megawatts at the Irvington unit would enable you to serve, it mitigates the RMR condition such that you could have additional generation beyond the RMR constraint. Likewise, in 2004, 35 at Irvington Unit No. 4, and then in 2005, you have two combinations where 55 megawatts would be required with Irvington Unit 4, and either Unit 1 or 4 at Irvington.

Am I understanding correctly what you have there as being the minimum generation required to resolve the RMR margin constraints?

MR. BECK: Yes.

MR. JERRY SMITH: If those units were on line during the RMR conditions, you would be able to competitively solicit for power of amounts above that level to meet your load, above the 55 megawatts, for example, in 2005.

MR. BECK: The load above that level could be competitively served. I'm not sure about your question about we could bid it, but it could be served by competitors.

MR. JERRY SMITH: Okay. The one thing that I'm seeing is missing in your report is we do not have the RMR energy number contained in your report. Is that something that you can provide Staff?

MR. BECK: Yes, we have those numbers.

Apparently they were left out of the report. So we'll get those to you.

MR. JERRY SMITH: And establishing those RMR energy numbers, are you looking at the energy above the SIL level? Are you looking at the energy above these minimum generation levels required to meet your local load?

MR. BECK: We look at them above the minimum generation unit.

MR. JERRY SMITH: So the annual cost that you're capturing here on the chart on the screen is the production cost for that energy that is above your minimum generation requirement to mitigate RMR?

MR. BECK: It's the incremental cost above that requirement. So to the extent we had to run a local generator, we took the production cost of that unit and subtracted out market price proxy from that and determined the incremental cost for must-run.

MR. JERRY SMITH: Is it the same basis of how you established, on Page 40 of the report, the emission pollutants for the RMR conditions? Is it the emissions that would occur above that minimum generation level.

MR. BECK: In that case, I believe it was just the total emissions for those units.

MR. JERRY SMITH: The total emissions for running local RMR of your units?

MR. BECK: Correct.

MR. JERRY SMITH: One last question from me, and that's regarding your establishing spinning reserve requirements. When you do your calculations for maximum load-serving capability, how have you been establishing what your local spinning reserve requirement would be?

MR. BECK: We just base it on the WECC criterion.

MR. JERRY SMITH: And that's based upon 15 percent of load or 7 percent of thermal units locally, loss of largest unit?

MR. BECK: That, in addition to SRSG requirements. So to the extent we have commitments through SRSG to possibly provide a different level of spinning reserve, that is also taken into consideration. But basically it's the WECC standard of 15 and 7.

MR. JERRY SMITH: That's all the questions from Staff. Any last moment questions from the audience?

(No response.)

MR. JERRY SMITH: Thank you, Mr. Beck.

Our next presentation will be from Western Area Power Administration, and let's go off the record for a moment while we set this up.

(Brief pause.)

MR. JERRY SMITH: Let's go back on the record.

Mr. Charters and Mr. York, if you could present your study results for the river system study. And while you're making introductory remarks, I will get your presentation up on the screen for you.

MR. CHARTERS: Thank you, Jerry.

Jim Charters, Western Area Power Administration.

A couple of things that we need to understand in our presentation is that we're not the load-serving entity in the area that we study. We are the transmission provider in the load-serving area that we study. We did this study based on the fact that we were the transmission provider.

In addition to that, it's important to understand what kind of a weird creature Western Area Power Administration is. Western is a power marketing administration under the Department of Energy, and our primary function is to bring the energy from the dams on the Colorado River to the preference customers, wherever they may be. In this case, most of them are south of Phoenix here or down in the Yuma area.

So what you will see in our study, and use of our transmission lines, is that there are load-serving areas in Mohave County that are our customers. There are also load-serving entities in Mohave County that are not our customers. And we do provide the transmission to get to those places.

The other thing that you'll find in our study is that we have independent power producers in this area, the Griffith plant in the Kingman area, and the Calpine South Point plant in the -- which is at Topock Wash, or it's just north of Needles.

The load-serving entities that we address in this are the Citizens Communications -- that always blows me away -- the Mohave Electric Co-op, the Harcuvar Power Service, which handles the Mohave Reservation, and the City of Needles, which is, I understand, on the other side of the river, but we don't, as a federal entity, worry about the river. It gets in the way sometimes of the power lines, but...

So what you will also find in our study that Leonard York will present, is that -- I'll let the study actually show it, but the power lines were built to haul energy right on by this area, not to serve the area, so we are serving it with excess capacity.

The other piece of this puzzle that makes it really interesting is that Western does not have a load-serving responsibility or load growth responsibility; load-serving yes, not load growth. So upgrading of the transmission lines in this area would be something that would have to either be mandated from Congress or somebody else to pay for, that we would be able to upgrade them that way.

So those preliminary explanations, I hope you spelled that better than I did, and most of you all knew this already, but I thought I'd repeat it just because it has a lot to do with how we approach this.

How are we coming, Jerry?

MR. JERRY SMITH: Just about there.

MR. CHARTERS: I forgot to tell Leonard that it had to be a CD-ROM. Sorry about that.

Are there any questions about what I just said? I can probably try to answer them in some way, shape, or form.

(No response.)

MR. CHARTERS: Independent power producers in our system are very independent and they probably do not serve -- they actually are not responsible for serving the local load, and most of them have transmission, all of them have transmission to get essentially back to economic hubs or independent hubs.

MR. YORK: The RMR study, it's study objectives were those specified in the RMR document. Items 1, 2 and 3 were done in the study. Items 4, 5 and 6 were found not needed, and so it's not further addressed.

1 is the import limit with all the internal generation turned off. 2 is the maximum load that the system is served with generation maxed, and some reserve, some generation reserve maintains. 3 is a generator list. 4 are RMR conditions which we did not have a need to run any internal generation at projected peak load conditions. 5 would be effectiveness of new facilities if they're required to mitigate RMR. And 6 is comparative analysis of those alternatives.

Figure 1 shows how the system was defined. It's arbitrary. Pretty much everything along the river, south of Vegas, all the way down to Yuma, Arizona. And along the river, the cut are all the facilities that WAPA has responsibility for, and then towards the Arizona side, everything that was pretty strongly electrically tied to the river system.

Next slide, please. This is a listing of all the generators within that river system. Jim mentioned some of them. Griffith and South Point are two fossil units, and Blythe is one under construction, going through start-up testing now. Next slide, please.

There are the older hydro units, Davis and Parker. The total generation, if we summed all these up, would be -- seems like I messed up that slide right there. 1824 for fossil, and an additional 364 for the hydro. Next slide, please.

Let's see. The projected peak loads for 2005 are as listed. Jim was saying we have Harcuvar, APS, the CAD project under SRP, SRP, CUC, a desalter plant the government has, MWD pumping plant at GNE, Mohave Co-op additional peak load. Northstar Steel has an electric arc steel plant, and WAPA has some loads with Wellton Mohawk. Next slide, please.

The results of the study are that our SRL -- I mean SIL limit was reached at 1335. There was a total load in the system of some 1300 megawatts. There was no import across the boundary, the net import was zero -- pardon me, the net import was 1335. There was no internal generation, and the limit was caused by what the WECC calls a post transient delta V limit of a maximum of 5 percent for an N-1. In the study, only N-0 and N-1 conditions were examined. N-1, you take a significant element out, it's like a line or a transformer leak.

For the particular WECC 5 percent delta V limited occurred at Peacock 230 kV substation. That bus dropped its voltage 5 percent below what it was prior to the outage, and that was caused by the Peacock transformer outage. The maximum load-serving capability was found to be almost 1700 megawatts.

We had another post transient delta V limit occur. It occurred at the opposite end of the system, at the Bouse 161 kV, which is just south of Parker. That occurred when the Parker/Bouse line was outaged. As a result, that particular substation is radialized from the Yuma end, so it's hanging off of a relatively long line. They have delta V that occurs at 5 percent.

And in this case, our total generation was about 1750 megawatts gross. There was 53 megawatts load generating op. that supports those units. That pretty much concludes this study. I could go into study methodology, but it's pretty much the same as everyone else.

I mentioned we came from a CATS HV case that was developed to run studies on the Arizona system.

It was modified according to the participants in this study, all the various utilities and entities in this river system, and then from that particular case, which might have almost been termed an economic dispatch at generation, we developed two cases, the SIL case, where all internal generation was turned off, and to replace that generation, we took about 50 percent of it out of whoever, and Glen Canyon, about 50/50 from each of those, and the remaining 50 percent came from the L.A. basin, various big units they have around Los Angeles.

For the maximum load-serving capability case, again, we started from that modified CATS HV case, and increased the generation up to a max, minus some reserve for margins.

If there's any questions...

MR. JERRY SMITH: Questions from the audience?

(No response.)

MR. JERRY SMITH: Staff has a couple of questions for you.

You have given us the load projections for, I believe it was the year 2005. That's the time period you studied. Can you identify how much load growth occurs in 2003-2005 in the study area?

MR. YORK: It seemed like it was about a little less than 3 percent per year.

MR. JERRY SMITH: The load numbers that you had in the report were not as extensive as the loads that you had in your chart this morning. Were some of the loads in your chart this morning outside this constrained area?

MR. YORK: No. They're all within the boundary of the river system that's shown in Figure 1.

MR. JERRY SMITH: Your Table 2 for your report had the 2005 peak load at 1296. If I read this number correctly on this chart, you have 1824.

MR. YORK: That's incorrect, Jerry. And I can see Table 1, Sheet 1 and 2, and Table 2 all have 1824 as the sum, and when I was cloning them off, I didn't correctly sum Table 2 or the bottom of continued Table 1.

MR. JERRY SMITH: Are the numbers in the report the correct number?

MR. YORK: Yes. As you say, the projected peak load is 1297.

MR. JERRY SMITH: Since you have described this system, it appears to be voltage limited. Can you provide Staff with the var capabilities for the units in your Table 1?

MR. YORK: Yes.

MR. JERRY SMITH: Because we know that that is a factor in resolving that voltage constraint.

MR. YORK: Unfortunately, it has post transient delta V constraints in both maximum the load-serving capability case and the no internal generation SIL case, only it occurs at different ends of the system.

MR. JERRY SMITH: You have studied the two extreme conditions for that load pattern. Is there a generation pattern that could result in problems for the transmission system?

MR. YORK: I could make an estimate. For Bouse, I don't think so, because the problem with Bouse is as long as it's radialized from the Yuma end, if there's no generation on that line from Yuma back to Bouse, then that's going to have a delta V limit there that's going to bind it. If a plant is built on that line, say like at Wellton Mohawk, then it will alleviate that delta V constraint.

MR. CHARTERS: Which is one of the plants that are in planning. Let me clarify that a little bit. Western Area Power Administration, in conjunction with Arizona Public Service, has been studying a plant called the Wellton Mohawk generation facility, used to be called York, and that plant will hook up at Wellton Mohawk, and will actually connect into the system as well at North Gila on 69, and I'm sure you're well aware of that. I'm repeating that for the thing here.

And from what Leonard just said, that will help the situation in that area.

MR. JERRY SMITH: That generation project is at the very southern end of the system that you studied?

MR. CHARTERS: It is, Jerry, but if you take Parker/Bouse out, the only place you get to Bouse is from down there.

MR. JERRY SMITH: Is there any impact with the generation assumptions for the Blythe generation project?

MR. CHARTERS: I don't understand the question.

MR. JERRY SMITH: When you had no load generation for yourself, was the Blythe plant operational or not in the case?

MR. CHARTERS: Did we have Blythe turned to SIL?

MR. YORK: All the units shown in the table here, in the generator list, all those were turned off for the SIL condition. Blythe, which is right now planned to be two CTs, one steam, that was turned off, all units were turned off in the SIL case. All units at Griffith, South Point, Davis and Parker, they were all turned off in the SIL.

MR. JERRY SMITH: I'd like to talk about the SIL number for just a moment. You've identified the SIL limit as being 1335, and if we take the 2005 load forecast, which is 1297 megawatts, and we add to that the auxiliary station loads for the generators, which is 53 megawatts, according to your report, the total load becomes 1350 megawatts.

What is the minimum generation required to be on line, to be able to serve that peak load? Because the 1350 megawatts exceeds your 1335 SIL limit.

MR. YORK: That's a good question. It's one of methodology as well. And the crux is if units are not committed, if they're off line, would their aux load be the same as if all of the generators were on, and I don't believe it is the same. I believe that there is a -- that the aux load does go down if you're not running any units at all as opposed to having all units on and maxed.

So 53 megawatts is a number for the amount of load to serve all units running. So the number would be less than 53, but greater than zero. So I'm not sure exactly what the, when the units are not operating at all, what their load would be.

So let's say it's some number, say it's in the neighborhood of 50, like you were saying 53, 50. Then I don't know, Jerry, I don't know what to say on that.

MR. CHARTERS: Jerry, if you take the -- Jim Charters, Western. If you take the -- and assume that when the generators are off, they have just the lights on in the control room versus the pumps and stuff for the generators, you get a different number entirely. We're not sure what that number might be. Do you want us to -- what you're saying is you're so doggone close let's find out what this is.

MR. YORK: But I can make an estimate right here, and I'd say because of the location and type of constraint, location is on the northern end of the system, at Peacock, for the Peacock transformer outage. So if you add load on the river side in the south, you're not going to impact that delta V, so you can add aux load at Blythe or Parker, and probably at South Point, no problem. Davis still, probably it's going to be iffy there. Adding into Griffith is going to impact this, as you move up towards the point that's constraining us.

So if we're going to add it, you know, an amount of load, and let's say the amount of load, it's not going to be the full 53, but some number probably more like 20 percent of that, so that's distributed among all those generating stations, which it would be, then I don't think the delta V is going to change a whole lot at Peacock, because most of the load is not going to be added near Peacock, it's going to be added further away.

MR. JERRY SMITH: Since we're in the process of speculating what results might be, since you have studied only through 2005 load forecast, and you're basically at the system limit or the system's capability load-serving wise for SIL, does that imply, as we move forward in time through the 10-year planning time frame, that it might become a problem area as load grows, if there is not transmission improvements?

MR. CHARTERS: Since that's a political speculation answer, it is our belief that something needs to be done in the area.

MR. YORK: Unless the WECC changes its post transient delta V requirement. Because we don't hit thermal limits and we're not really hitting V limits, and as far as load stability limits, I'm not seeing load stability limits hit either. But we are hitting what the WECC enacted almost two decades ago.

This post transient delta V has been under consideration by various groups within the WECC to revise it or eliminate it. And as well, it's also a fairly soft criteria that a lot of utilities relax as they move away from the metropolitan areas, because they just can't meet it. The voltage change from an N-0 to an N-1 in outlying areas tends to be a lot greater than the metropolitan areas where the system is really tight.

MR. CHARTERS: Leonard, let me answer Jerry's question the way Jerry wanted it to be answered. That's true, the RS is considering stuff like this. The RS is a subcommittee of WECC.

MR. JERRY SMITH: RS standing for reliability?

MR. CHARTERS: Reliability subcommittee. I never keep those acronyms straight.

But recall that my remarks, when we started, were that the transmission in the area is not necessarily being used for the area, so you've got a real concern here of mixing essentially a simultaneous import limit, assuming that the area was being served by the transmission versus -- it's the old problem of what is contract versus what is power flow. And where you're at here is we are also contract limited already in the area, and so there's got to be some stuff done in the area to take care of that fact.

Whether this area has its power flow taken care of or not doesn't necessarily assure that transmission is provided into the area for load-serving. It's like the freeway went right by, and granted, I can still see it, but I can't get on it or off it.

MR. JERRY SMITH: Given that we're talking about a voltage constraint again, and when you looked at the maximum load-serving capability, did you make any assumptions regarding reserve requirements in the units that you were modeling?

MR. CHARTERS: I'd like to respond to that in a similar manner to what Ed did earlier. The units in the area carry reserves based on the WECC criteria, and based on their membership in the Southwest Reserve Sharing Group.

I believe -- maybe I ought to ask Dana. Is Griffith in SRSG?

MS. DILLER: It's been accepted. We're going through all the communication protocol.

MR. CHARTERS: Dana Diller from PPL. She basically said they made their application. I know that's a similar thing to Calpine South Point.

Is there anybody here from Calpine South Point?

(No response.)

MR. CHARTERS: I know that we have for the Davis and Parker, and we know that Blythe is working on that as well.

MR. JERRY SMITH: Thank you. That concludes my questions.

Let's go off the record for a moment.

(A recess ensued.)

MR. JERRY SMITH: Let's go back on the record.

Our third presentation this morning is from Arizona Public Service Company, Mr. Cary Deise, and it will be regarding the Yuma area. And then hopefully, we can get through that before lunch, and we'll take a lunch break and then commence to have Mr. Deise go over the Phoenix area RMR study this afternoon.

Mr. Deise.

MR. DEISE: Thank you, Jerry. We're passing out the presentation, including the Phoenix, so if you get enough of it at lunch you don't need to come back after lunch, I guess.

MR. JERRY SMITH: Speak closely into the microphone.

MR. DEISE: Like I said, we had 40 copies of the presentation. I don't know if that's enough for everyone. You can always share.

It includes the Phoenix one, so like I was saying, if you've seen enough of it, after lunch we can all go home, I guess.

Hearing no response...

MR. JERRY SMITH: You are an optimist, aren't you?

MR. DEISE: I will start with the Yuma one. Jerry and I talked a little bit, it may be a little easier to lay the groundwork for RMR before we move into the valley.

The way I have the presentation broken out for both Phoenix and Yuma is we start to describe a little bit about the network and its constraints, talk about our determination of the SIL and MLSC, get into some of the numbers that Jerry wants to see on RMR, the demand, energy and duration.

Then we have some sensitivities. We're going to look at economics, environmental impacts, the transmission constraint. In that same, we'll also talk about sensitivity of generators, how they impact the imports.

Then the last one will be the impact of additional transmission facilities on the RMR, then we'll have observations for each one of these.

Starting with the Yuma area, I'd like to talk a little bit conceptually what we're trying to do with calculating the SIL. I know other people have mentioned it, but I'd like to emphasize it again, the objective is to determine the maximum load that you can serve in a load pocket without any generation. So that's your starting point, while at the same time we need to meet the WSCC criteria.

There's some questions on N-0. I can address some of that right now as long as we're talking about the Western Electric Coordinating Council. It has criteria, you look at N-0, continuous, you look at N-1 and you look at N-2. Can you get a different number as far as what the import capability is for each one of those. What we report here is the most limiting one. For us that will be the N-1 number we'll be recording.

What you do for the N-0 is look at what we call our base case and see if any element is overloaded. If it's not, you look to your N-1. We haven't calculated N-0, but it is not our limitations on Phoenix or Yuma. You take the most limiting of those critical outages. You need to meet the WECC criteria when you're looking at this SIL.

Next for my reliability viewpoint, you need to measure the load that's going to have the most significant impact on the severity of the critical outage. So what you're trying to do is find out what is driving this system from a load viewpoint. What loads are causing this system to be limited. And that's part of what we're trying to look at from a reliability viewpoint.

We've heard the term a couple times, load pocket. Phoenix and Yuma identified this load pocket. Part of the goal, then, in calculating the load pocket is to make sure you capture all the load. And basically what you do is you measure the line flows from all the EHV delivery points to the load center. That's how you calculate that number.

And you can see that for Yuma, it's a bit of an oval up there, and since it, quote, cuts lines, it is sometimes referred to as the cut plane. So again, you're trying to find out all the loads you need to cut all of the lines.

Then finally, when you do these studies, you do need to model all of the WECC systems so you don't have the APS system modeled by itself, you have all the WECC systems modeled. So that's kind of a background where we come from and where we're looking at the SIL.

For Yuma, it basically has three delivery points, if you will, into the system. First one over in the northeast part of the Yuma Valley is the North Gila substation, 500 lines coming in from Palo Verde area then heading on to San Diego. Then south of there you have Western's Gila station, 161 to 69. And then over on the west side along the river we have the Yucca power plant, which is co-owned by APS and Imperial Irrigation District.

Out of each one of these you have the lines, like I said, that are coming from the delivery points into the load. We have two lines coming from North Gila that we've shown going in to serve load. We have one line from Gila going in to serve the load. Then you can see we have three lines coming out of the Yucca power plant going to serve load. So those are the lines that we're going to be looking at when we talk about what the SIL is for Yuma.

When we start talking about the generation that is inside this network, we have the Yuma

Cogeneration Association generation that we've known as YCA. Then at Yucca, we have the steam unit at IID, and APS has four combustion turbines at that site. Outside of Yuma but of general note is CT No. 21, Imperial Irrigation District, combustion turbine on the 161 heading over to Pilot Knob. So that's the basic description of the Yuma area.

Now, getting onto the part where Jerry wants to start seeing some numbers. We start doing technical studies to find out what the limitation is without any generation. When you look at this, this is what we refer to as a nomogram. It plots the area on the Y axis there, plots the load, then it plots the generation that's inside that. Again, the IID and APS and YCA generation. It may not be readable from, in the back there, but hopefully you have copies of it and you can see that when the generation is zero we've noted that the SIL is 164 megawatts. So in the Yuma area, you can import 164 megawatts without any generation on it.

In the studies we then go adding more load into the area, and matching generation to make sure we don't violate any criteria. When you look at Yuma, you can see that the critical outages, what you'd expect out of the strongest, but the 500 kV at North

Gila. You see a slight reflection in the curve there because load generations would tend to overload an IID line when you get up to the higher generation's internal 69 line. Yuma's import capability with the generation is determined by the North Gila outage, then thermal ratings of lines. So it's not voltage limited.

The other thing you can tell from looking at this is that if you add 160 megawatts of load in the Yuma area, and go up to about 320, then go across the curve, how much generation do you need, you see you've got to add 160 megawatts of generation. So what this is saying is you have pretty much a one-to-one match; for each megawatt of load you need to serve above the SIL, you're going to need a megawatt of generation. This is a pretty good, strong indication that we have the proper nomogram, proper cuts, and we're monitoring the appropriate variables down in the Yuma area.

Now, we take the number that we had, the 164, this is a little different plot than what Jerry put up already. This is an hourly plot of the load in Yuma through the year. And then we draw the 164, and anytime the load is above the 164, that's what we have defined as RMR. And you can see for Yuma, other than maybe the fall, October, November time frame, every month has some RMR in it.

What we like to do to help -- this isn't the easiest to look at and analyze and understand all that's going on. What we're going to do is take these numbers and form what we call a load duration curve. We won't plot them chronologically like we have them here. We'll plot them from the highest to the lowest. The highest is about 312, and looking, you see a load of about 80 megawatts. This is that plot. You can see at the very top it's plotting load against hours. You skip the peak number 312, and you can see through the hours, it goes descending on its way down to about 80 megawatts of the lowest load. This is a curve that I think helps in analyzing and showing you tutorially what is going on in the Yuma area.

So again, let's go back to the SIL of 164. When you draw that across there, what this tells you is all the load above that, in other words, the difference between 164 and the peak load of 312, that is your max RMR. You can see mathematically, that's 148 megawatts. On the peak hour in Yuma, the RMR requirement is 148.

And you can see as you go through the various hours in the year, that number slowly, actually goes down pretty rapidly, out to where you have no RMR at all. In addition, by looking at that, where the SIL crosses the load duration curve, you can see there are 3512 hours in the RMR area in the Yuma.

Additionally, you can look at how much energy is needed of RMR, and that's the shaded area up there. The energy there is 162 gigawatts, which is about I believe slightly less than, it's about 10 percent of the loads would be RMR.

So again, catching what we have on this diagram, the information that Jerry's been looking for is you have an RMR energy of 162 gigawatts, a peak of 312, with an RMR peak of 148, and the SIL of 164.

I forgot one item. We choose just one year for our presentation. We did all three years, but we thought we're not adding on transmission so we just picked the middle year of 2004. Pretty much -- the numbers change a little bit, but the basic concepts in what we have follow for all of them, and all the numbers are in the report. So this is what you get for Yuma.

Next, we took a little different approach. We didn't call it MLSC, but what we did is we took the same thing as the definition. We took the SIL of 164, we took the APS generation at Yucca, 139, then we did a resource adequacy study, where we looked at a probabilistic approach of serving the load in Yuma of a 98 percent probability.

When we did that calculation, it says the installed reserves should be about 70 megawatts. These are not operating. This is looking from a planning perspective, and looking out to have an adequate reliable system we think we need 70 megawatts. You subtract 70 from those other two additions, so you get that APS, with its SIL and its generation, minus its reserves, can serve a load of 2303 megawatts. Again, you draw it on the same curve that we're talking about. And when you look at this, you can see now you're pretty much just the summer months that you have an issue with RMR.

Again, we're going to take that same load curve and draw it up there again, but now rather than looking at just the SIL, you can see we have the MLSC of 2303 megawatts. Now you see that 148 shrinks to 79 megawatts of nonAPS RMR is required. You see the generation requirement shrinks down to only 27 gigawatts. And I didn't do the math on that one so I don't know what percent that is. Probably getting down to a couple percentage points now. So this shows the impact of the generation in the Yuma area. You can see the hours significantly drop from 3500 down to

964. So this is the impact of the MLSC on the Yuma area.

Now, moving forward, so we have an idea what SIL is, MLSC and the hours and the gigawatts that are out there, the next part that basically Jerry said. We wanted to know what is the impact of this transmission constraints, what if they are not there in Yuma, what would happen to capacity factor, energy output to plants down there. He also wanted to know environmentally what happened. So what we did is we took a program known as the GE maps, multiple area production simulation. It's basically a marriage of the traditional power flow and a production costing, where it does an economic dispatch of all the units, while it honors any transmission constraints.

So what we did for this analysis to find the impact is we first run this study and we have it honor, if you will, all the constraints. If it finds a unit that may be economic to dispatch but would violate any transmission condition, that unit is not dispatched. So that's the first case, and that would be with the constraints. We then tell the program don't worry about the Yuma dispatch what you think is economic, and tell us what would happen.

So you can see from these capacity factors, the APS units practically don't even run if there was no constraint. It drops from a 4.1 percent capacity factor to .2. The IID steam doesn't serve a load, it matches the dispatch for need, it doesn't change. Likewise, the YCA is sold to San Diego, you don't see any change. So we did provide the capacity factors for those just to give you an idea of the total area down there.

Now, what we did next is determine the economic impact. You recall early on, we showed that the RMR was 162 gigawatt hours, and what this study showed is of that 162, looking in the left side, 113 of that is economically in the money. In other words, these are units that are economic to run. They're in what you might call the market price, and should be dispatched, they're economic independent of the transmission. That's roughly 8 percent of the load.

It also shows that of the RMR energy, you have about 49 gigawatts that are out of the market. So this is the bottom line that's telling you down in Yuma, for the year 2004, with the loads and resources forecast, you're going to have 49 gigawatt hours that would not be in the market, would not be economic to run. If you didn't have the transmission constraint, you wouldn't run them. It also shows you that 89 percent of the time, there is no RMR requirement in Yuma, and that's basically what this chart is showing.

It also shows you that 49 gigawatts, when compared to the outside market, has an incremental cost of $1.3 million. So it's saying the cost of RMR in Yuma is 1.3 in the year 2004. And we've got similar numbers for 2003 and '5.

The last part was a question on environmental impact. We put these four because really they're the ones in Phoenix, but let's talk about them anyway for just a second.

First one is volatile organic compounds. We show how much the number is reduced, but Yuma does not, at the present is not an attainment area for that, so we don't know of any data that monitors that, so we put it unavailable. It's not tracked, it's not an issue right now in Yuma.

Same thing with the NOx and carbon monoxide, although again, we gave you the numbers. The one, it is a particulate matter that's the 10 micron order and you can see that it changes, the constraint changes that .003 percent. So if you remove the constraint, you would reduce the PM-10 by .003 percent. So this gives you the economic impact on Yuma.

As a final part of the technical studies we did for Yuma, we took a look at what transmission we could possibly do in the Yuma area. Yuma area electrically is pretty far from any major sources, so you've got long lines and high expense for most of it.

But what we looked at is going back, the critical outage again was the North Gila transformer overloading the internal system. So what we did is we took a look at let's put a second transformer in there and see what that does to the import. Again, if you look at the zero generation, you can see that the SIL goes from the 164 to 274. So it would add 110 megawatts to the SIL, and you can see it comes very close to eliminating the RMR condition in Yuma.

We then compared that, tutorially here we show you what we're talking about, in that you see over at the North Gila, there's a circle around the additional transformer. We put a 500 to 69 additional transformer at North Gila. Cost estimate of approximately three and a half million dollars to install that. As we stated, the savings are about $1.3 million a year. So this has a payback of around two and a half million -- two and a half years. Sorry about that. So it looks like an attractive economic alternative to the Yuma area.

Summarizing our observations in Yuma, as we mentioned earlier, RMR hours are about 3500. We have an economic impact of the constraint, transmission-wise, of 1.4 million. We see that we can construct something down there at three and a half. It was something that we're going to pursue the installation of that second transformer, and briefly again, the transmission constraint, the removal of it would reduce PM-10 by .003.

That's my presentation on Yuma, and I'm open to any questions.

MR. JERRY SMITH: Do we have questions from the audience?

MR. LARSEN: My name is David Larsen, Navigant Consulting. I'm here on behalf of Wellton Mohawk generating facility.

We are passing out -- we had developed a list of, a data request that was sent to APS after we had the opportunity to review the report that Cary and his folks put together, and subsequently have had some discussions with Cary and some of the other people at APS, and had gotten some of the information that was requested.

But right now, based on where we are coming from, I guess, I think there are like three major points that we would like to keep in mind as we go through completion of this process.

The first is the study that was done by APS and that Cary described focused on one, what you might say system operating condition that was, didn't, for example, have the Blythe energy project facility on line at rated capacity, and the second was the east of river power transfers from Arizona into southern Nevada and southern California were relatively low, at least in our opinion. And we think that if we were to look at those kinds of conditions as part of this whole process, primarily because based on some preliminary work we've done, we see it shift the results a little bit.

In other words, Cary mentioned that the North Gila outages at the bus at North Gila tend to be most critical. It appears to us, if you look at some of these more stressed operating conditions, that you might in fact see the 500 kV line from Hassayampa to North Gila become a limiting contingency.

The second point that we wanted to bring up actually consists of two different items. It's our understanding at the present that in addition to the facilities that Cary has shown on his double diagram, there is a second 69 kV line that goes from Western's Gila 69 kV substation, basically into the very southern portion of the Yuma area, and ends up moving through that portion of the system over towards the Laguna substation of APS'.

That particular facility was modeled in the RMR studies at the line itself, but there were no loads attached to it.

The indications that we've gotten from talking to folks at Wellton Mohawk Irrigation and Drainage District is one of the partners in the generating facility that's there could be, up to 10 megawatts of load can be served from that line, and we feel that's something that should be investigated, and if in fact that's the case, that load should be included within the load pocket.

MR. JERRY SMITH: What was that line, again?

MR. LARSEN: It's a line that goes from Western's Gila substation. Basically this line here. It goes from Western's Gila substation to the Sonora substation at 69, then the 34 and a half kV between Sonora and the San Luis substation over in the Yuma area.

The other item we're probably not quite as critical, but I think you have to understand is the matter is the 69 kV line that goes from North Gila, and my understanding extends northward up towards

Senator Wash. There again, we have been told there could be upwards of eight to ten megawatts of peak loads from this line at times, and is something also that should be considered as part of the analysis for the load pocket.

We had a question on APS relative to the reserve requirement. Like I mentioned earlier, we had some discussions with your folks this morning, and I believe we've got a satisfactory answer for that particular item.

I guess the third major area I think from a technical perspective gets back to what Cary was talking about earlier, is the need for the second transformer at North Gila, and whether or not it would be offset by some local generation, for example, that would be provided by the Wellton Mohawk generating facility. We initially had some questions about the estimated cost for that transformer installation, the APS folks were kind enough to respond to that question yesterday. I think we're reasonably happy with the answer we got on that.

MR. JERRY SMITH: Mr. Larsen, are the comments that you're making, are they going to be filed in this docket?

MR. LARSEN: Yes. We brought some written documents along with the data request attached to it that we agreed to submit with APS three- or four-page document, kind of summarize what we saw as the issues, and where these things stood with regards to resolution on them on Friday.

Like I mentioned, the comments are in -- our initial comments are developed on behalf of the Wellton Mohawk project. We will be planning on doing some additional technical studies into some of these issues, such as the impacts of the Hassayampa/North Gila imports and so forth. We hope those could be done in conjunction with APS such that we can get the matter resolved to everybody's satisfaction. That applies to the, just the loads and the load pockets, and other items I mentioned.

MR. JERRY SMITH: Mr. Deise, did you want to respond to any of those?

MR. DEISE: Sure. Probably respond first with the answer where I think we need to go. They've sort of hinted at it. The point is Dave and I and the engineering staff that I have with me sit down. These are relatively easy things to look at, not like I need another three months to study the issues that he's brought up. I think rather than him running a study and me running one, we have dueling studies, I'd rather sit down and agree on what to do. It might be easier to look at the records and match what -- modify and match what you have. To me that's the bottom line.

MR. LARSEN: I will mention to you, we have run some studies based on the information that APS had provided, and luckily came up with exactly the same results, so I feel pretty comfortable about not the dueling issue, but two people doing the study.

MR. DEISE: When you're concerned about 10 megawatts, again, when you're looking at the limiting element of 69 across there, how much of that 10 megawatts is going to end up there. I'm not sure how much that 164 will move, but I see that as a relatively small number that this can move, so I'm not expecting a big shift in the SIL, and all the numbers that we've seen. I think they're going to be very close to what we've seen.

For instances, the Senator Wash, when you take the bus outage, that line gets dropped, so the load doesn't matter. Again, we can discuss that but I think the bottom line is for Dave and my engineering staff to work that out.

MR. LARSEN: The only other comment was I'd like to make, I mentioned earlier the Hassayampa/North

Gila outage. Based on some stuff we did before the data from APS, it looked like some conditions, that might push the import down by 10 or 15 megawatts.

MR. JERRY SMITH: Mr. Larsen, let me make sure I understand the context of that comment. If I understand what you're suggesting, is that under a different operating scenario which would have high east of river flow conditions, that you think that the outage of the North Gila transformer may not be the critical outage, that it could be loading on the Hassayampa/North Gila line for some other outage?

MR. LARSEN: No, it would be the outage of the 500 line itself, Jerry. The Hassayampa line outage causing more of the problems on the system within the Yuma area.

MR. JERRY SMITH: Let me ask Mr. Deise, at North Gila, what is the bus configuration at North Gila for the 500? Is the transformer tapped on the line back to Palo Verde or is it a ring bus?

I guess what I'm asking is how much of the 500 kV system remains intact delivering to North Gila for a Hassayampa/North Gila outage?

MR. DEISE: It's a three breaker ring to allow any element of the other two to stay in service. When we lose the Hassayampa/North Gila, you still have the Imperial Valley to North Gila and the transformer in service.

The question, too, may be how high do you want to go with these to the river for what we're trying to do the work here? We've put in what we think is a typical summer day, and that's what we have tried to work at. We have not tried to stress all parts of the system. So that's where we come from.

MR. LARSEN: What we did, I think we increased east of river transfers from 3100 megawatts to 4300 megawatts or somewhere in that.

MR. DEISE: What was the number?

MR. LARSEN: I think it was 3100 to about 4300.

MR. JERRY SMITH: Thank you very much.

Anyone else with comments?

(No response.)

MR. JERRY SMITH: Staff does have a variety of comments we would like to ask on this study area.

First of all, I think I want to suggest that the modeling in this study seems to be pretty accurate in terms of defining what is the load area that is being constrained, and I found it very helpful in the report that it identified all of the transmission elements that make up the sum of that import capability.

One of the questions that I have relates to the fact that you're looking at a thermal loading limit in the Yuma area, and if I understand correctly, in your studies, you have modeled some improvements which are contained in Table 4 of your report, Page 25, and you identify three capacitor bank installations at the 69 kV system totaling 96 megavars. And it appears that at least two of those three installations had been advanced from 2006 to an earlier year.

If those capacitor bank installations were not to occur, would there be voltage stability limitations for this area as well?

MR. DEISE: I don't think it would be voltage stability, but it would be what Leonard York was talking about, 5 percent voltage deviation problem would be occurring without those capacitor banks.

MR. JERRY SMITH: What drove the advancement of those capacitor banks in your planning studies?

MR. DEISE: To maintain 164 import capability, make sure that wasn't eroded.

MR. JERRY SMITH: So that the import capability, the SIL would be less than 164 without the capacitor banks?

MR. DEISE: That's true.

MR. JERRY SMITH: You also include in that same table some 69 kV lines that get reconductored during the time period of this study.

Were the cost of those capacitor bank advancements and the reconductoring of 69 kV lines included in your $3.5 million estimate of construction in the area to remove RMR limitations?

MR. DEISE: No, they weren't. As I recall, those removed -- if you take a look at the table, you see the items in the base case there, then you see what we did for the sensitivity.

MR. JERRY SMITH: Yes.

MR. DEISE: Those items in that sensitivity are what's added in there.

MR. JERRY SMITH: So the reconductoring of the Foothills to Foothills tap and the 32nd Street to Avalon 69 kV line are included in the 3.5 million?

MR. DEISE: I'd have to check and make sure. I do know for sure that it's the transformer 500 breaker and the 69 section breaker. I'd have to check on whether those advancements are in there.

MR. JERRY SMITH: The other thing I would like for you to explain here is a little more about how you determine your local reserve requirements from a probabilistic perspective. Can you explain that again, please?

MR. DEISE: I'm making a note here. I think what I'd like to do on that, Jerry, since we would be breaking for lunch, we do have the expert here who did that, is take any other questions you might have, then come back and save that for last. I'll get down, then let him get up. We have Mr. Paul Smith, your cousin, here that can explain that. In fact, he explained it to Dave Larsen this morning, so we can do that.

MR. JERRY SMITH: I would also request that you provide the var capabilities for the machines in the local area. I believe you provided a table that lists the capacity of the units in the report, table 11. But if you could provide the var capability of those machines, that would be most helpful.

MR. DEISE: Okay.

MR. JERRY SMITH: The next question I guess I would pose to you is relative to what you have described as APS' maximum load-serving capability for the Yuma area. Would you look only at the APS generation, and I think what we have been looking for from a system perspective was what is the capability of all local units plus import. And I assume that from a megawatt capacity standpoint, that's simply an addition of nonAPS units to reflect what that local load-serving capability would be. But from an energy perspective, I think that it would be helpful if we knew what the total energy capability of those local units would be above SIL.

MR. DEISE: I'm not sure I understand the question about the energy above the SIL.

MR. JERRY SMITH: You have captured your SIL requirements and associated RMR energy.

MR. DEISE: Right.

MR. JERRY SMITH: Let me find the numbers here. Ranging from 143 gigawatt hours to 186 gigawatt hours is the energy that's RMR constrained. That's on your Table 9 of the report. It's reflecting the numbers that you showed us earlier in your chart for 2004, where you have the hours and the bullet on the screen, the first bullet, you're showing the hours, the constraint exists as 3512 hours. You have the energy as 162 gigawatt hours. Then you turn around and run some capacity assessments to determine what you described as an energy that's out of the money.

I think what Staff has been suggesting throughout our Track B proceedings is that we aren't looking for capacity and energy that's just out of the money, we were looking at the total RMR energy and total RMR capacity.

MR. DEISE: And we provided those.

MR. JERRY SMITH: You have provided those. I just wanted to make sure that you understood that we have, Staff has a different perspective in terms of what portion of that would be contestable.

MR. DEISE: I wasn't trying to address contestable. I was trying to identify RMR and what its impacts were. Just how you handle the contestable, I assume you'll deal with on Friday. But what we tried to show here in the Yuma, the 113 that's in the money, and the 49 that's out, you add that, that's the 162, so that's the total RMR, and for Yuma, the only units that are moving with and without the constraint are APS units. So this is all APS energy, then, in the Yuma area --

MR. JERRY SMITH: When those energy numbers were established, are you establishing what is an economic dispatch for APS locally?

MR. DEISE: When you do the constraint, yes. The constraint case -- well, the terms, we're all going to have the same price. If you get in the constraint case you can't bring anything from the outside so you increase the APS generation at Yucca. In the unconstrained, they only dispatch them if they are the most cost effective in the whole WECC, not just the Yuma area, not just APS. Does that help?

MR. JERRY SMITH: I think it does. What you're addressing is the dispatch assumptions in maps, when you look at the nonconstrained you would look at the whole generation in the WECC system?

MR. DEISE: That's correct.

MR. JERRY SMITH: And it would consider the most economic dispatch of those units?

MR. DEISE: With any other constraints other than Yuma. We still need like the Pacific intertie. We just take this constraint out, all the other constraints in WECC. It would take the most economic dispatch for WECC.

MR. JERRY SMITH: As you did your comparative analysis of alternative solutions, you look at the cost of that differential energy between constrained and unconstrained map simulation; is that correct?

MR. DEISE: That's correct. That's where the 1.3 million comes from. It's the total economic dispatch with the constraint, without -- they're different by 1.3.

MR. JERRY SMITH: And the environmental emissions numbers that you've provided is for that same differential dispatch?

MR. DEISE: Same cases, yes, sir.

MR. JERRY SMITH: Is it fair to say that there might be additional cost avoidance if there were new local generation that could operate more economically than the APS units?

MR. DEISE: As opposed to the transmission constraint?

MR. JERRY SMITH: I'm saying if you leave the transmission constraint as is, you have assumed a certain part of that constraint would be resolved by APS units, local units, and I'm asking -- and then above that, there is a certain amount that you're assuming could be purchased from the market as a whole.

What I'm asking is if there were new generation locally, could it also possibly economically displace the APS units to mitigate?

MR. DEISE: Yes, sir. Let me make it clear I understand your question. If someone new came in and put a generator in the middle of this bubble here, and that unit was cheaper than the gas turbines that APS has, then the answer is yes.

MR. JERRY SMITH: So, if you were looking at that scenario, you would be looking at the cost of dispatching from those new units locally versus dispatching your own units as being the comparison of the two scenarios?

MR. DEISE: Yes. Again, make sure I understand.

MR. JERRY SMITH: Both from a cost standpoint.

MR. DEISE: If you had another, again, we're not looking at putting a second North Gila. You're just saying another alternative, someone to come in with a generator that gets you, and that's, make it simple, it's 110 megawatts just like the transformer, this same analysis then works where you still save the $1.3 million in the Yuma area, yes.

MR. JERRY SMITH: So when we look at the cost and the emission numbers that you have, if there were other units locally, they could displace more RMR energy and result in a different local plant emission than what you have captured in your report?

MR. DEISE: No. I think when you look at the capacity factors, you pretty much have the APS units shut down, you see what you saved. What's not in here is what the outside pollutants are going up by. If you're going to put one in there, you have to add those back in. I don't know which one wins, but the bottom line, if you're driving capacity factors down to .2, they're basically off line and they're not polluting then. So you can't do much better than that, if you're going to eliminate the import capability of constraint.

MR. JERRY SMITH: I believe that concludes all the questions I had for you, Mr. Deise.

MR. DEISE: Thank you.

MR. JERRY SMITH: Are there any other questions?

MR. DEISE: I'm sorry, I forgot. Paul Smith from Arizona Public Service will address your questions on reserves.

MR. BAHL: Cary, I had one question. Prem Bahl, Staff.

If you look at the alternatives and take -- and consider emissions, pollutants and cost of those emissions, you compare those alternatives with alternatives like restoration of North Gila second transformer or other special entities, in other words, in your economic evaluation of alternatives, you have taken into account the cost of emissions?

MR. DEISE: No, sir, we did not take any cost of the emissions.

MR. BAHL: I mean whenever you have an alternative and it results in some emissions, an alternative generation source, you also take into account -- or in other words do you compare those alternatives with nongeneration alternatives, such as installation of a second transformer you mentioned here?

MR. DEISE: It sounded like the same question. We didn't put any economics to the environmental at all. The cost comparisons are production cost differentials and the construction of the transformer.

MR. BAHL: Okay.

MR. PAUL SMITH: The reliability analysis of the Yuma area is really fairly simple, because there's only four combustion turbines that we have there. They're different sizes, and that makes the reserve number fairly high, if you're looking at reserve margin or capacity margin, two units about 20 megawatts and two units about 50 megawatts. So what we do is go through and look at all the possible states of those units, either being on or available, I should say, or forced out. So these units have a forced outage rate of about 10 percent. So you can say the probability of all four units that would be forced out at the same time is .01 percent.

So we go through all of the combinations, figure out how much capacity the plant can produce statistically, and then what we do is we go to the point where we reach the 98 percent reliability level. So in other words, how much capacity do we believe could be delivered 98 percent of the time. That amount of capacity or more. So what that comes out to be the 70 megawatts -- 69 megawatts is what we say can be served 98 percent of the time, and then the remaining piece of that is a reserve margin.

Okay, now, when you translate that to a much larger system, such as Arizona or the southwest, and you translate that into something that you're more familiar with, like a reserve margin, it does turn into about 15 percent when you take it to a large level. But because Yuma is such a small system, and because there's such a big difference in the sizes of the four units, you come up with the seven megawatt reserve margin.

MR. JERRY SMITH: Is that means of determining a reserve margin requirement a WECC planning criteria or is it something used strictly by APS?

MR. PAUL SMITH: It is not a WECC planning criteria, it is a criteria that's used by APS and has been used by APS for some time now.

MR. JERRY SMITH: Thank you.

If there are no other questions, I'm going to suggest we take our lunch break for the day. Let's take an hour lunch and we will start this afternoon, then, addressing the Phoenix import capability. Thank you.

(The lunch recess ensued from 11:25 a.m., to 12:41 p.m.)

MR. JERRY SMITH: Let's go back on the record.

We have on our agenda today one additional presentation, and that is a presentation by Arizona Public Service Company regarding the Phoenix area RMR study area, and Cary Deise is still before us and will present that material.

We're back on the record.

MR. DEISE: Thank you, Jerry. I'm going to go back again, we are going to do the Phoenix one just like the Yuma one, but we're going to talk about what the network is, its constraints given the SIL and MLSC, talk about the RMR, the demand energy and duration, economic impact, and what additional transmission does, then observations.

The only difference -- and I didn't mention Yuma, we didn't do a sensitivity because all the generators in Yuma are basically in the same place. I think YCA can't be two miles from the Yucca power plant. You can see it from the power plant. They're all there together. We didn't do a sensitivity. I'm sorry, I didn't mention it earlier.

We have a number of sensitivities on the generation in the valley and outside. The precursor is I'm not presenting all of what's in the report. I tried to pick a year and demonstrate the points, so the numbers like that, that Jerry wants for his score card, they're all in there. I just didn't think he'd want to see the same repeat three times, and the numbers don't move that much. We don't mean to leave anything out, just a way to shorten up the presentation, if you will, a little bit.

I would like again, before I talk about the Phoenix network, to talk again about what we're trying to do. And the first thing we're trying to do is find the maximum load that APS and Salt River can serve in the network, and honor the WECC reliability criteria.

Again, from a reliability viewpoint we're looking at the load that's going to be the most sensitive to causing violations of that criteria, if you will. In other words, that are significant to the impact of those outages. Then, of course, if you're going to talk about pocket, you need to meter all the lines or measure the flow on all the lines out of the HV delivery points into the load center, then much like Yuma, we do represent all the systems in the WECC are represented.

So let's walk our way through the Phoenix, talk a little bit about network, do some sensitivity and talk a little bit about the Western system.

This is not the diagram that's in the report. The one in the report shows all the lines. We tried to simplify it a little bit, maybe get a better handle what's going on here. The main objective is to show you the four corner points, that being Westwing, Pinnacle Peak Road, and Kyrene are the main delivery points. We've also shown the generation that is inside this network, Salt River's Agua Fria, APS/Pinnacle West, West Phoenix, APS Ocotillo, Salt River's Kyrene and Santan. Not a precise location, but to give you some idea of where they sit in the network, and why that's important, is the critical outage is the Jojoba to Kyrene line. And the limiting condition is a voltage collapse in that Kyrene area. So generators that can provide voltage support, the closer they are to that, the more they bring to the import capability.

That's why we try to show them that way. When you look at the results, even though I won't go through the impact of each one, you would see in our report that Kyrene and Santan bring more than, say, Agua Fria, which is further away from that.

I think -- with this network, we have cut all of the loads except for Mesa. So when we talk about the Western system, we don't have the Mesa load, it's not the whole City of Mesa population, it's just the municipality part downtown. It's about 80 megawatts. It is in the study, so its impact is there, but for monitoring nomograms and results, we pull it out because Western, as we show up there, does have lines coming in to serve that load. So we've pulled that out.

If you've had a chance to read our report, we are certainly open, both us and Salt River, to other options you want to do with Mesa. Again, 80 megawatts out of a 10,000 megawatt load, it's not going to change the results significantly, but we're certainly open to other possibilities with Mesa.

The other thing you can see when you look at these cuts -- and we'll talk a little bit -- you can see that Western is actually outside, it connects to basically the 230 buses at the delivery points, but it didn't have lines that come into the valley. They basically encircle the valley. In other words, they have lines, we show it there from Pinnacle Peak to Westwing to Liberty. They're on the outside. If you try to do this metering we just talked about, you're going to have flows come in and go out and they will be basically zero, so you won't get any import capability from them.

Likewise, the only load they have is Mesa, so there's no load you're capturing when you're trying to measure a load pocket. So that's why we haven't per se included a Western nomogram. We do have their system in there and we do have the small Mesa load. Any benefits, if you will, Western or any other system, and APS, Salt, it's all mutual support. We all provide reliability to each other, and that's basically what's going on with Western.

So given that background, much like Yuma, we start our studies off with the calculation that we mentioned up here, load pocket calculation. I suspect you can't see those numbers real well, but hopefully everyone has a copy.

What you can see for the valley in the year 2004, you see a SIL of 8632, so that's with no generation on. You can serve a load of 8632. Again, the limiting outage is the Hassayampa to Kyrene, and it's a voltage collapse in the Kyrene area.

And much like Yuma, we march up this nomogram, if you will, as you add load, we've got to add generation, and if you take a look, if you add about 1500 megawatts of load, which should take you to about 10,000 on the load, and you move across there, you'd see you need 15,000 megawatts of generation. So what you're seeing is each megawatt of load that you add, you're going to have to increase the local generation that we identified earlier in the nomogram to be able to operate in a safe area.

Then, of course, we take it all the way out to its maximum. One of the questions you asked, Jerry, that I didn't know you wanted at the time, but your question was, as I recall, I believe in Tucson, what is the minimum generation that's required for RMR. You can look at it, this diagram would give that to you, in that if I told you in 2004 the load is 10,339, and you went across there, and you went down, you would see that it requires a generation of 17,007 megawatts. So that is the minimum for the peak load in the year 2004.

MR. GULDNER: Cary, 1700.

A VOICE: Hundred not thousand.

MR. DEISE: Among friends. I'm sorry, 1700. That would be the minimum. We can do that per each year for you.

You might also note, in 2000 for the installed generation in the valley, APS, Pinnacle West Energy, and Salt River Project is 2822.

Also, much like the Yuma one, you can see if you go out to the end point here and you subtract off the approximate 2800 megawatts of generation, you're going to get back down to the 8600, so what you're seeing again on this nomogram is you're seeing we are identifying the appropriate load and generation for determining the capabilities of the import into the valley.

Before we take those any further, in Yuma, you may recall, the next step was to take you to the hourly load duration curves. But what I'd like to do is talk a little bit about sensitivities of the generators before we go to that. And again, we did it for all the valley, I just chose to pick one, the Ocotillo unit.

What we did is we increased the generation at Ocotillo by 100 megawatts, basically increased the load in the Las Vegas area, if you will, 100 megawatts, then we calculated where did all those flows go when we did that. So when you look at Ocotillo, you can see all the flows go out. So what they're doing is they're backing off all those ties for you.

So what you can do, then, from a load-serving viewpoint, is just schedule that back in the opposite direction, so you can, for the 100 megawatts you scheduled out, you could either schedule another 100 in, or if you don't want to go to Vegas, you could serve 100 megawatts of APS load.

In the report you'll also see that actually Ocotillo does a little better than that, I think it gets 134 megawatts. Again, if you went back and looked at Ocotillo, it's fairly close to the southeast and it's providing some var support, if you will, so it gets even more than 100 megawatts that it's generating, it gets some support from its voltage.

Next, we took a look at Panda. And what happens with Panda, because it's outside of the network, all of its flow is basically just flow -- that do flow in the valley, flow through it. When you look at the numbers, close to probably 85 percent of theirs stays up on the EHV system. You can see it loads up the Rudd a little bit, and the Kyrene, and backs off Pinnacle Peak and Westwing. With these net loadings, you don't get to serve any more load because this flow-through doesn't back off the flows on the total cut.

The other issue probably with Panda is that critical outages, Kyrene to Hassayampa, and Panda is on the other side of that, so it's very difficult for it to get voltage support over to the east valley. The biggest enemy of vars is distance. They're impossible to ship them.

The other situation we may also have going with Panda, and I show Panda a little different because it doesn't go directly into Hassayampa, but all those, Hassayampa, Palo Verde and Panda, we have so much generation vars out there that taking one off just doesn't do that much for you on the impact of voltage over at Kyrene. Now, if we were down to Panda maybe was the only generators in town out there, you might see more of an impact. But you have such a large amount to choose from out there already, that we don't see Panda changing the import limit to the valley.

And next one we did, Hassayampa. It's a little different in outage than Hassayampa -- excuse me -- Panda for another reason. Panda does have a 230 kV tie with APS, and the numbers are a little bit different. Let me get to the right one here. They're down just a couple megawatts. I think Panda had eight going out of Westwing, and seven out of Pinnacle Peak unloading it. They're basically getting the same type of result. The tie in to Liberty doesn't do that much with respect to the valley import capability.

The last one I think is kind of interesting. Sundance. Again, Sundance is not in the valley where the cut plane is. I didn't show it on here, but it lies outside, and you can see that by its flows, you can see that it's coming in on the east side and going out on the west side. See pretty good unloading on the Westwing lines that are coming there.

The other key thing I think you see with Sundance is it's not too far from the east valley, so it is providing some voltage and var support. So what we found, although Sundance is not in the valley, it does add, for every hundred megawatts, about 34 megawatts of import capability increase, so it's not in, but it still sees an increase.

To kind of close this out on the sensitivities, we need to keep in mind as the system expands, these sensitivities can change, and also the unit providing increase could be a detriment down the road. Let's just say, for instance, that down the road, that the limitation is not the Kyrene area, but it's the line loadings out of Pinnacle Peak. This one here would show you that Sundance has a negative impact on that. So keep in mind, just because you showed in the time frame of 2004 a benefit, it doesn't mean that it goes on forever, and who knows what surprises there will be next year when we look at the full 10 years.

One of the things we'll capture in that time frame is the Palo Verde/Southeast Valley line. We haven't done any work on imports and what's the trickle on that one, so that may change the impact on APS and Sundance. Likewise, in the 10-year plan you'll also see the APS Palo Verde lines up to Table Mesa, you may see some different impacts on the sensitivities.

Now, like with Yuma, we put the daily curves. I didn't do the calculation for you in the presentation, but you take the 8632 that's the APS Salt River, we have an allocation of that, in 2004 that allocation is 3,658. This is APS' share of the import into the valley.

Again, like Yuma, we drew the loads there, 24 hour. You can see that they're bunched pretty much in the summer. In fact, what we did, which we've already looked anyways, we blew it up and looked at just the summer as to when you're going to be in that kind of condition. So you can see looking at this that the RMR is going to be mostly in July, August, maybe towards the end of June, always be driven by weather. If you have a hot June, you can move it up; likewise, a cool July, you can move it the other way.

We did the same thing we did with Yuma. We're going to take the highest to the lowest and develop this curve that I think easily tutorially shows you what we're doing.

So again, you have the APS peak load of 4614 going down to about 1200 megawatts or there, like the Yuma one. We draw the SIL across there, the 3658, then the RMR requirement, as stated by what the Staff wants in the report, the maximum RMR is 956 megawatts. It's the difference between the SIL and the peak. The RMR energy associated with that is 211. Again, it's that colored-in area, that's how much energy is RMR. We show the number of hours, 590 hours of RMR for the valley in 2002. To put the 211 in perspective, compare that to the 20,000 megawatt hour load, you can see it's less than 1 percent.

Again, like Yuma now, we go to looking at the MLSC, the SIL is 3658, APS' west Phoenix and Ocotillo generation is 660. Paul Smith did the same analysis for the valley and found out our installed reserves need to be 190 megawatts. So you take those three numbers, add the first two and subtract, you get an MLSC of 4128 for 2004 for APS. Again, we draw the line across the summer, you can see now it's basically August and maybe the last week of July that you're running into nonAPS RMR.

Again, we take the same curve and we move up to the MLSC, now you see that the maximum nonAPS RMR is 486. You see it's dropped down to 42 gigawatt hours, and 200 hours out of the year, just looking at the APS units.

So what we've done so far is we've gone through what the network is about, what its limitations are, a little bit about the generation, giving you numbers that Jerry wanted in his score card. I think we have them all for him.

And then like the Yuma one, we're now going to go to the GE maps again and find out what is this constraint costing us. Again, to give you an idea, we take a look at capacity factors, gives us our first idea what happens. So you can see that again, we run a case that has the constraint, the 3658. You can see with the constraint, APS' units would have a capacity factor of 1.7. Remove the constraint, say it's not there anymore, it drops down to 1.

The total valley, this one we do a little different. This is everybody, APS, Pinnacle West Energy and Salt River, all of our capacity factors is about 7.8, and it goes down to 7.6 when we remove the constraint.

Now, again, we do the same thing with the energy. You remember, there was 211 that was out of RMR. We're not trying to change that number here, but we're trying to give you an idea of how much of that RMR is out of the market because that's what it's costing the system, if you will.

So in the GE analysis, looking with and without the constraint, there's 43 gigawatt hours that are outside the economic mark. In other words, if you could remove the constraints, that 43 would not be generated in the valley.

It represents about .2 percent of Phoenix load of APS. Likewise, you can see there's a .8 percent or 168 gigawatts of that 211, again, we have the total load of 20,561.

99 percent of the time the GE maps are saying you don't have any RMR that you need to be running. So that gives you the economics for the -- then we

have a similar slide for the environmental now. Phoenix does provide or the Maricopa County does provide some numbers on VOC and NOx, carbon monoxide and PM-10. You can see that again this is the same time we're trying to show how much average, 10 per year reduced, and what percent that is of the Phoenix area.

The main thing we looked at with being voltage limited in the Phoenix area was to look at the status var compensator. It's technically a little fancier than just a capacitor. Part of the reason we went for this is APS and Salt have already added 600 megavars in the Ocotillo/Kyrene area already. Adding more, you can't put them on during normal system because the voltage would be way too high. So you have a device that you can switch in and out when you lose the Hassayampa to Kyrene, so it was a little more expensive device we looked at, at cost of $16 million to install it. Yet the savings back from those energy is only 700 K. You're looking out over a 23-year payoff for something like this, this does not look like an economic solution to us.

So in summary, our observations, we see about 590 hours of RMR, less than 1 percent of load. You see about $400,000 in the year 2004 that are out of money. The construction, we couldn't get the static var compensator in force, so we have a cost in '5 which is $100,000 savings. It did not seem justified. I put the range of the percent decreased from .001 to .049 percent.

So that's the Phoenix. I'll take any questions now.

MR. JERRY SMITH: Questions from the audience?

MR. MOYES: Mr. Smith, my name is Jay Moyes, and I'm the attorney here locally representing the PPL interests. And obviously our most significant focus of interest being here today is in connection with our Sundance facility, to which Mr. Deise has made some references. We appreciate this process. First and foremost, we want to make that clear.

Back early in the fall in the workshops, we urged in those discussions that in our view, the transmission deliverability and RMR issues related to the Phoenix area load pocket were things that would prove to be vitally important ultimately, not only just in the competitive solicitation processes, but in the longer term transmission planning and regional planning processes, and we appreciate the fact that this request was made by the Staff, and we appreciate the effort that the utilities in this instance, specifically APS, have gone to to try to be responsive to those requests.

Back in December, we asked formally, in the form of a letter, for an opportunity to have our technical consultants, K.R. Saline & Associates, actually participate in the preparation of the studies. That request was denied, and we understand good reasons and bases for that.

But because it was, and because only the utility owners were able to participate in those study processes, we now find ourselves with a report with what has been thus far very helpful additional explanation, which in the last 10 minutes has answered some of our questions, though we frankly haven't had the kind of time that will be required to do the very detailed technical analysis of the studies. We don't have the kind of detailed system representations and other sort of data and information that ultimately is necessary, I think, to allow the, just the nonutility community the opportunity as well to continue to study and work in these processes.

I noted in the discussion with Mr. Larsen from Navigant and a couple of his questions, that Mr. Deise generously offered to work in a collaborative kind of dialogue process as opposed to having people continue to do two different paths of additional study analysis, and we would, I guess, urge perhaps a similar opportunity, and it will certainly be appreciated if we could, and we have no reason to think from our past dialogues and discussions with APS that they would have any objection to that.

We do have a lot of questions. We anticipate, Mr. Smith, that your list of questions will probably cover many, if not all of those. You saw the extent of my technical expertise on these things when I was able to get a microphone to work by having you push a button.

The only way I could bring anything to this process is have our technical consultants, K.R. Saline push the buttons, as it were. We do have them here today, but are pretty much at a disadvantage in terms of being able to exhaust the inquiry we want to make. We would defer, if it's acceptable to you, Jerry, to defer any questioning today of any technical nature to after you've asked your questions, and Mr. Deise has had a chance to address those. We may find that we don't have any more, we may have a few more clarifying questions. If we could do that, in that order, that would, I think, be more efficient for the purposes of everybody here today.

And finally, there was some reference alluded to earlier of keeping a record open. I don't know what the normal procedural constraints of this transmission assessment process are. I do know that we have, coming upon us very rapidly, the Track B Commission consideration, and some aspects of these deliberations are critical and relevant to that. Others are of the longer term nature.

We would appreciate if the record could reflect that the record will remain open as to this process, perhaps indefinitely, but at least certainly for a long enough period of time that we could prepare written comments. Hopefully, I hope we don't have to get formalistic like data requests, but Q and A type of interchange with APS that would help clarify for us a number of things relative to the way Sundance interacts in the system, the way things are, like the SIL allocations between APS and Salt River Project. I don't know how much incorporation of the Yuma load, as Cary alluded to, would have an impact on things, but we still have some questions relative to Western's system, to impacts of parties who own transmission on Western's system.

I have lots of places in the report that I've highlighted and colored, and I think we can probably more productively get to answers on those by an ongoing dialogue for which the record would remain open to allow the results of that to be formally submitted at some point.

So having said too much already, I will defer to others' questions, and again express our appreciation for the opportunity to be here, to have the process, and for the work that's been done.

Thank you.

MR. JERRY SMITH: Thank you, Mr. Moyes.

Other comments or questions?

(No response.)

MR. JERRY SMITH: I'm getting signals from several employees.

MR. MOYES: Mr. Smith, I'm sorry. I said Yuma and I meant Mesa.

MR. DEISE: Trust me, no Yuma load is in Phoenix.

MR. JERRY SMITH: I'm getting signals from some other parties that maybe they're deferring to Staff questions. Let me go ahead and proceed with those. If there are residual questions from other parties, we'll take those.

Mr. Deise, I'd like to start Staff's

questions by going back to your model. Let me suggest we bring back up the diagram of your system model.

One of the things that I think is not as clean in the Phoenix area study as it was for the Yuma area study is exactly what elements comprise the cut plane. And I think you have tried to generically, at least, identify that with the diagram you've provided, and also with Figure 1 in the report. However, I need to ask a couple of questions from a clarifying perspective.

When I look at Figure 1 in the report, I see you have tried to model the Western Area Power Administration lines that basically interconnect to the same delivery points between these same delivery points. For example, the Pinnacle Peak to Westwing, Westwing to Liberty, Pinnacle Peak to Rogers, and I believe you characterized those as being sort of a net sum effect on the system import loading analysis, because they simply are an in and out of the network, without any load being taken off of them.

I would ask why that same approach was not used for the Western line from Liberty to West Phoenix to Maricopa.

MR. DEISE: The Liberty/West Phoenix does not connect into the West Phoenix APS yard physically. It sits there, but there is not an interconnection at APS at West Phoenix. All it is is a step-down transformer there.

MR. JERRY SMITH: From 230 to?

MR. DEISE: 115, I believe. So there's not an interconnection there.

MR. JERRY SMITH: And how about the Liberty to Coolidge 230 line, since you are showing in Figure 1 the other end of that line from Coolidge coming back into Rogers?

MR. DEISE: There's no particular reason we didn't show it. I didn't think it added anything. But there is a Liberty to Coolidge. Again, that's some of what you're getting from the Sundance, with it being in the Coolidge area. We highlighted the Rogers because it was closer to where the voltage problem was, so you could note what was happening with Sundance.

MR. JERRY SMITH: Explain a little bit why you're showing Knox as a delivery point. Is that the Ocotillo to Knox to Santa Rosa transmission path?

MR. DEISE: It's the load in the valley served out of Knox, yes.

MR. JERRY SMITH: But the transmission involved with that, 230 line from Ocotillo to Knox to

Santa Rosa?

MR. DEISE: Kyrene, Knox, Santa Rosa.

MR. JERRY SMITH: Would it be appropriate to represent similar types of load out of the Liberty station for your west valley loads?

MR. DEISE: I don't think so, because the west valley load for APS out of Liberty is just a radial out of Buckeye and Gila Bend, so it won't have any impact. The load is steady and represented, but adding it in won't change the nomograms at all. Just move up the numbers by what the load is, it's just a radial load of about 60 megawatts out of Liberty.

MR. JERRY SMITH: I think you can sort of see where I'm headed with my line of questioning here.

MR. DEISE: No, not really.

MR. JERRY SMITH: My real concern is to what degree what is being characterized as APS and SRP Phoenix load includes all of the load that is served from this import system, or is it only those portions that you have defined as internal on these particular lines; or thirdly, is it simply a reflection of monitoring the flow on these combination of lines that is defining your Phoenix area, and APS valley load numbers.

MR. DEISE: I'm not quite sure I understood your question. What we've done is captured all the load of APS and Salt River in the Phoenix area. By cutting back in Figure 1, all these lines calculate the total load. The only thing that's missing is the Mesa load, and we don't consider Buckeye and Gila Bend in the area, and it's radially served out of Liberty.

We're not trying to find the value of each one of these delivery points. That's not what we're doing. We're trying to find out how much load can you serve in the valley area, that's what we're trying to do. We have to be careful if we're going to try and mix that with deliverability, because that's a different issue.

MR. JERRY SMITH: I think what I'm trying to suggest is there may be some inconsistencies in the model because of the approach of including and excluding particular lines and load buses in your numbers.

Let me give you an example. Your report states that the Raceway substation in 2003 is interconnected on Western's line from Pinnacle Peak to --

MR. DEISE: Raceway is out of Westwing.

MR. JERRY SMITH: I'm sorry, I said Pinnacle Peak. Then in 2004, the Gavilan 230 load is interconnected on Western's 230 line from Pinnacle Peak to Prescott.

MR. DEISE: Correct.

MR. JERRY SMITH: And your statement in the report is that those loads have been excluded from your valley load number because -- let me find the words here -- service to these substations will not use APS import capability.

What import capability are you referring to?

MR. DEISE: The SIL up here.

MR. JERRY SMITH: So you're saying those loads are not served by the cut plane elements that you have identified?

MR. DEISE: That's correct.

MR. JERRY SMITH: How are those substations served?

MR. DEISE: They're served off of Western's system. APS would deliver to Pinnacle Peak, then it would flow up to Gavilan Peak, it wouldn't flow into the valley. Likewise, we do the same thing at Westwing, deliver the 230 bus at Westwing and have it go out into the Raceway. So it doesn't come into the circle at all.

MR. JERRY SMITH: The fact that they're viewed as radial lines out of these major delivery points doesn't mean that they aren't delivered from the EHV system of these delivery points?

MR. DEISE: I didn't say they were from the EHV. Don't mix it up with deliverability. We're talking about what the SIL is for the valley. I would agree with you, if you're starting to talk about deliverability you can deliver the Westwing load to Westwing 230, that doesn't impact the RMR on the valley. We need to keep focused on RMR, not deliverability. Separate subject.

MR. JERRY SMITH: What I would like to suggest for future consideration, as we model this area of the system, is that we include all Western lines in the cut plane from these EHV delivery points, and that we consider the summation of what is flowing on those lines much as you did in the Yuma area, even though there may simply be some flow-through for Western's delivery system. And I think that is also the way to capture in the future the issue about the Mesa load that is also served by Western's transmission lines.

That way, we have a consistent determination of what the total system importability is that reflects not only just serving the local load, but the flow-through that must accompany all of these lines for other purposes.

MR. DEISE: I think we're going down the wrong path here. We'd be willing to analyze that for the next 10-year study and do it. But again, especially when you're taking a look at a radial load, it doesn't change any of the RMR, whether it's the demand energy or the hours that are in it. All you're going to do is move all of the curves up by what that load is, both capability and the load, so you don't get anywhere.

I'm not sure. Are we going to ask Western now to rate their system of what that import is to Phoenix? They've never done that. I mean you're taking a whole different stance. If you're not careful, if you're just going to throw in there all of what Western's system is worth, if you can't serve any load on that, I think you're really getting a false picture. That's why I come back to what we've done, is monitor the load that is sensitive to the critical outage. That's what we've done here, and that's what's important.

MR. JERRY SMITH: Would you agree it's hard to find whose power is flowing over which of these lines, APS, SRP, Western or others?

MR. DEISE: Sure.

MR. JERRY SMITH: Would it not be easier to refer to the total flow that's the composite of the total uses of that system?

MR. DEISE: I don't think so with Western, not the way their system is set up. They're not serving any load. I don't think it works.

MR. JERRY SMITH: I did hear you say, though, that the RMR capacity energy numbers would simply be increased by the amount of these radial loads.

MR. DEISE: No, I think you get the same number. I think all you do is now you're going to move the SIL up. Because when we did this study, we did serve those loads. All you do is move the SIL up and the load duration curves, so you end up with the same number.

MR. JERRY SMITH: In deriving these SIL numbers, these loads were in there and modeled, and flowing over whatever paths they occurred.

MR. DEISE: Right.

MR. JERRY SMITH: Is it inconsistent, then, as you do an evaluation of your RMR capacity and energy, that you would subtract those loads out?

MR. DEISE: I don't think there's inconsistency as long as you've also subtracted out the capability with it. The two go together.

I'm saying if you want to try and expand the network, add those loads, the SIL is going to go up by the same amount as those loads. So you're going to end up in the same place as far as the energy and the RMR capacity. There are differences.

MR. JERRY SMITH: Let's move on.

MR. BAHL: Jerry, can I ask a question on that curve?

Cary, on the slide that you have here, I have a question about Sundance load-serving capability increase, which your Table 3 shows to be 35 megawatts. If I look at the red arrows, they add up only to 20 megawatts, is it, or am I not reading it correctly?

MR. DEISE: The arrows are giving you where the megawatts are flowing, this doesn't capture for you the impact of the voltage support Sundance provides for the southeast valley.

MR. BAHL: Is it a result of that voltage support that we see in Table 3 that the load is 35 megawatts?

MR. DEISE: Yes, sir.

MR. BAHL: Thanks.

MR. JERRY SMITH: Since we have started talking about your generation sensitivity study results here, the flows that are shown in red on this are intended to show the incremental change in flow over those delivery paths as a result of 100 megawatts scheduled locally from Sundance; is that correct?

MR. DEISE: Yes, sir.

MR. JERRY SMITH: And accompanying that is a reduction of local generation by 100 megawatts?

MR. DEISE: No, sir.

MR. JERRY SMITH: So you did not adjust local generation, you just increased generation at Sundance by 100 megawatts?

MR. DEISE: And I increased the load in the Las Vegas area to 100 megawatts, with outside...

MR. JERRY SMITH: In essence, with the simulation that you've done, you have basically assumed a delivery from Sundance to Las Vegas?

MR. DEISE: Yes, sir.

MR. JERRY SMITH: So we're looking at a net flow-through of the 230 system?

MR. DEISE: Yes, it should come pretty close to zero.

MR. JERRY SMITH: Is that consistent with our prior conversation about how to handle radial loads or how to handle flow-through deliveries over all the transmission paths?

MR. DEISE: They're not related, so I'm not sure there is an inconsistency problem here. We're trying to find a network impact of Sundance power plant. This is one pictorial way of showing you.

In the studies, if you want to go further, again, we're trying to show between the four plants what happens and provide an explanation of why plants are in and out. If you go and look, we actually did a full var margin analysis. In that case, we actually added the 34 -- we added the load in the valley, and that's where the 134 comes from, or the 34, so we actually did those curves for that and did take a look at the voltage. We do have those studies, and those studies are consistent.

MR. JERRY SMITH: Those studies are different than what you're depicting on this diagram.

MR. DEISE: Yes.

MR. JERRY SMITH: That's helpful. This diagram is also looking at fictitious conditions, it's not looking at outage of the Jojoba to Kyrene line?

MR. DEISE: That's correct. We could have applied it to those, too. We thought this was more helpful.

MR. JERRY SMITH: When the total valley SIL is established, that is a number that you're saying is a combination of APS and SRP deliverability locally, with no generation; is that correct?

MR. DEISE: I don't like the word deliverability, but it is the SIL for the Phoenix area, yes.

MR. JERRY SMITH: As you establish what portion of that SIL is APS capacity, you're basing that on your ratio of load to the total load served locally?

MR. DEISE: No, sir.

MR. JERRY SMITH: That's not correct? Please tell me what the --

MR. DEISE: That was the initial, where we started back in -- I'm sorry, I don't remember the exact year. I want to say it was either 2000 or 2001. The original was a load ratio that we negotiated out. We agreed, though, as time went on, the increases would be allocated based on your expenditures or participation in new projects. Since that time, we have shared 50/50 with 600 megavars at Ocotillo and Kyrene, so we share that increment increase in capacity 50/50.

Also, these studies have the Palo Verde/Rudd line in which are 50/50. So we get any 50/50 of whatever that increase. So we're up a little bit from the 41 percent we started with. I think we did a calculation, I think we're at 42.6. It's very close to the load ratio.

But I want to make it clear that you just can't always take the load ratio. It depends how much you are involved in the increased rating that the system brought. For instance, if the Southeast Valley line, we have a smaller percentage in SRP, and it's not related to our load ratio.

MR. JERRY SMITH: It would be helpful for the next study that's required for filing in January of 2004 for you to give some detailed description of how you're determining what portion of that combined SIL is attributable to Arizona Public Service Company.

MR. DEISE: Okay.

MR. JERRY SMITH: I will put back on the screen your 2004 SIL valley nomogram. And in this nomogram, you've captured the SIL for 2004 is 8632 megawatts, and have indicated that that SIL can be increased by roughly a thousand megawatts by bringing on 1500 megawatts of generation. If you look at the data point in the middle of the curve that roughly reflects that.

MR. DEISE: It's a little bit more than that.

MR. JERRY SMITH: About 1200 megawatts of SIL increase for 1500 megawatts.

MR. DEISE: Probably, yeah.

MR. JERRY SMITH: What I've seen in your tables for generation sensitivity is sort of an inverse relationship of what you've described on this figure. You're showing that for 100 megawatts increase in local units, at various locations, that the SIL increases between 110 and 147 megawatts, which seems to be having a greater impact than what would be reflected on this nomogram. Can you explain that?

MR. DEISE: Yeah. You've got to realize that load is just the opposite of generation. When we bring up generation, we've got to bring up the load also, so you're going to see the load in the Kyrene area that's going to have more than a 1 for 1. It's going to need one point for generation, too, as opposed to generation that gets up towards Westwing. So it's the two of them coming together that balance that out.

MR. JERRY SMITH: Maybe it would help if we could describe how you determine the relationship of how the SIL is impacted by the 100 megawatt increase in various generators locally. Could you describe that again? When you add 100 megawatts at Ocotillo, and did your var studies, how did you determine that the SIL would increase by 141 megawatts?

MR. DEISE: Just a second. I'm going to find the table here. I lost my place. I'm sorry.

MR. JERRY SMITH: Let me try again, Cary. I apologize for everyone, this can get a little complicated, so let me take it slow here.

I'm referring to Table 2, Page 21 of the report, which documents your generation sensitivities inside the Phoenix area. And you're showing that by increasing Ocotillo generation 100 megawatts, the SIL would increase by 141 megawatts.

MR. DEISE: The SIL didn't change. The load-serving capability. SIL has no generation.

MR. JERRY SMITH: I'm sorry.

MR. DEISE: The load-serving capability. What we did is we put a 100 megawatt steam unit on at Ocotillo, ran our load curves, and at 100 it was more than acceptable, so we added 10 megawatts of load. I'm sorry, I chose the first one, Agua Fria -- maybe I should pick Ocotillo. We ran at 100, didn't show any problem. We increased the load. We may have went to 125, it's still okay. We went to where we increased the load 141 megawatts and we were at our voltage stability again. That's what we did.

MR. JERRY SMITH: Can you relate that to this curve that we have on the screen? It's saying that you increased generation 100 megawatts, and yet the load-serving capability increased 141.

MR. DEISE: I can't do it from that. I'd have to go and see where that 1500 megawatts was at.

MR. JERRY SMITH: Even if we take the worst case scenario that you have in this generation sensitivity study, which was Agua Fria, it was saying that the load-serving capability increases greater than the generation that's put on line.

MR. DEISE: Right.

MR. JERRY SMITH: Is that what this curve on the screen is showing? It shows that -- doesn't it show that the load-serving capability increases less than proportional to the generation netted?

MR. DEISE: It's made up of two components; I'm not sure which one is which. It's made up both what the transmission system is responding to and what the generator is. I can't, from this table, dissect that for you. I'd have to look into that further. I didn't try to dissect it that far.

MR. JERRY SMITH: I don't have an answer here either. I just saw a phenomena that seemed to be inconsistent in terms of the relationship depicted in Table 2 and what I see on the nomograms that you have provided.

MR. DEISE: Again, I think it's because of where you've added the load. But again, you can't tell that from the table.

MR. BAHL: Cary, just a suggestion. Some other people might also have that question that Jerry just asked. Would it be better to explain that with a footnote to that table which shows the discrepancy between increase in generation source and corresponding increase in the load-serving capability?

MR. DEISE: I don't know about where the report is going, if you're going to reissue it. I'm not sure where things are going.

MR. BAHL: I mean for the future.

MR. DEISE: Did I need to provide an explanation, whether that's a footnote or not?

MR. JERRY SMITH: I'm simply trying to gain some understanding here, Mr. Deise, and hopefully, before we get into the next study, we can understand the phenomena, and we won't have this confusion.

MR. DEISE: We can look into it and provide a reasonable response to that, yeah.

MR. JERRY SMITH: Along the same line, what I am seeing on Table 3 on Page 21 is something that does seem to coincide with this nomogram in terms of how it's depicting generation external to the Phoenix area, what degree it can be effective in resolving the voltage instability that is the criteria limit, by showing that when you increase 100 megawatts at Sundance, that the load-serving capability is only increased 35 megawatts in the valley.

I assume that it is implying that local machines are stronger voltage, and var supply units, than the units that you have studied in Table 3?

MR. DEISE: Part of it's the distance. If you take Unit 3, which is the furthest from the valley from the load, you can see it has impact. If you can march into it just outside of the cut but you're close to that area, you'll see that impact. It's not so much in or out, but how close are you to the voltage problem that's important to these voltage points.

MR. JERRY SMITH: You tried to give an explanation earlier how we could project what the minimum generation requirement was to meet the local peak load condition. If we look at Table 2, would it be fair to say that it does matter -- if we look at Table 2 and Table 3, it does matter which units are scheduled in terms of how effectively you can mitigate the load-serving capability?

MR. DEISE: Yes.

MR. JERRY SMITH: When you modeled the Santan generation, was that sensitivity reflective of a time period when the new Santan generation units -- I believe it's 4 and 5?

MR. DEISE: We used 5 in our study.

MR. JERRY SMITH: Okay. I guess the question I'm asking is the Santan generation that you're modeling here, was it assuming the existing units that are there today, or is it also addressing the presence of new units scheduled for 2005?

MR. DEISE: For the total study of the load-serving capability, we used the whole unit. For sensitivity, we basically used one of the existing units as opposed to 100 megawatts.

MR. JERRY SMITH: I believe we had asked, in previous studies today, for parties to provide us the Q max and min for the generators. Could you do that for this study area as well, please?

MR. DEISE: Yes, sir.

MR. JERRY SMITH: I think the next step I would like to take in my questioning has to do with both your understanding of the constraint itself, and in doing that, I would like for you to do two things. One, walk us through an example of a QV nomogram that we have that establishes the constraint, so we understand what the information is on that nomogram;

and secondly, if you could describe how the var supply capability and voltage regulation capability of local units are modeled in the power flow.

MR. DEISE: Can I take the second one first?

MR. JERRY SMITH: You sure can.

MR. DEISE: Give me just a second, because I think I may want to, actually, if everyone's got their Appendix A, I may want to pull one of these out to help me through. Can you give me just a second to prepare?

MR. JERRY SMITH: Sure. I might even need to consult with one of my engineers to make sure I've got the right case.

It might be helpful if you could use as an example your 2004 that goes with this present diagram, Cary.

MR. DEISE: I was looking for 2003.

Let me start with Jerry's easier question, and try to get through the cryptic at least down here. When you look at a generator and what its capability is, generally, generators come with a capability that looks at how many megavars reactive power, Q, whatever you want to call it, that that unit can produce. You put this on one axis, then you look at the power that it can produce on this axis.

And there's a relationship with these that looks something like this. And usually when you talk about a unit, it will have a rating of this is the power, and you go up here. So this is the rated power, you go across here. This is the Q, or the amount of vars that you put in the power flow that unit is allowed to generate.

Likewise, it comes down here and there's another Q. In fact, let me be a little more in general. This thing is not symmetrical and the bottom half tends to look more like a smaller one. So you have a smaller Q for how much it can buy what Jerry is questioning. This is the Qs we put in the power flow. As you can see, if you were to back off these power plants and they were only running here, you could have more var output, or likewise, if you were running them here, you can move them up here. It goes either way.

So his question is dealing with what are you doing with these Qs, and that's why he's asking for these mins and max.

Is that what you were looking for, Mr. Smith?

MR. JERRY SMITH: We are good. The Q max that is put in power flows is typically that quantity that correlates to the maximum megawatt output.

MR. DEISE: Rated.

MR. JERRY SMITH: Rated output of the unit?

MR. DEISE: That's correct.

MR. JERRY SMITH: When would the Q max and min be the greatest? Would it be at the minimum dispatchable amount?

MR. DEISE: Each unit is different, but this thing gets pretty flat. It won't get much below 50 percent or whatever. Probably in the 50 percent range, I would say, is the maximum of the vars.

MR. JERRY SMITH: So there is built in some conservatism in power flow when you use the Q max and min or the emaculated megawatts for the units.

MR. DEISE: Yes. Do you want to make this more complicated talk about cooling it with hydrogen? Plot A-20. This is in the industry and in particular in WSCC.

The standard way of looking at, can you meet the voltage criteria -- let me go back for a second. The phenomenon we're trying to capture is when you look at a traditional stability, it's usually something, if you're going to have instability, you have it happen in usually a number of seconds, at the most.

When we start looking at these voltage instability and collapses, you're talking about a phenomena that's happening one to 10 minutes out, so you don't run a traditional stability or power flow to do that.

The way that work is done is you literally, like this one here is the 2004, and there's a whole series of these, but the idea is to keep increasing the import into the valley and plotting what the vars and voltage look like. And you keep going, and the criteria is what you want to do is you want to find a point for the outage of the Hassayampa to Kyrene, the voltage profile would look just like this, often called a nose curve. This thing just hits zero, you have found your import limit.

So at -- I'm sorry, I forgot the number now, 8532. At 8,532, with the outage of Hassayampa to Kyrene, you will have, looks like the voltage is about, at the nose, 938. So you have established your stability limit with that power flow going into the network. So that's the simulations that we do.

In WSCC, though, they apply a 5 percent criteria. I should have done the math. So the number was probably 9500 megawatts was what was imported to get you this nose curve. Then because this criteria calls for a 5 percent margin, that's where you end up with the 8632.

So that's how the studies are done. You just keep increasing the load in the area till you get to where this thing just touches zero in the Q/V curve.

And that's what I mentioned about meeting WSCC criteria. It's fairly easy in Yuma, when you're talking about thermal. The other thing, you look, someone might say Mr. Deise, I see 25 megavars. The problem you have with voltage, it's not like power, it's very nonlinear, it's almost like a cliff. You can be going along and increase one megawatt and you're over the cliff.

So it's very difficult to get this exactly at zero like I've done it. So that's what you'd like to do. By going a little negative seems counterintuitive. This is actually showing a margin of 25. It's a little bit conservative with the 25. We tried to move it a couple megawatts, instead of minus 25 we had a plus 25. I think this is the closest we could get. If you'll look, you won't find where the nose curve that's at the top half. You want it to be at the bottom half. I think the worst we did was a 60 var margin. Does that answer it?

MR. JERRY SMITH: I think you've got us most of the way there. Let me ask a couple questions. Each of the data points that are on this plot on A-20, does that represent a separate simulation that's looking at what the voltage at that particular location is for a particular transmission import level?

MR. DEISE: That is correct. If you take a look at 20, there's about 10 different points. So what you're doing is we have the power that we were talking about coming in, then you're going to vary the vars at Kyrene and plot them through this way until you get to that nose point. So yes, there are 10 power flows to determine that stability limit.

MR. JERRY SMITH: And the var quantity that is being plotted there represents what?

MR. DEISE: It is a strength of a system, it's not a real equipment. So what it's saying is this, at this level, this system has the strength that you could, if you wanted, what a 25 megavar reactor at Kyrene, and it would still be stable. It's right at the margin, and again, that's why we want to have 5 percent. You're right. We've been talking about a lot of things that could move slightly on you. If they move in the wrong way, you could be unstable. So the idea is back off 5 percent. When you look at imports of 10,000, we're saying there's about a 500 megawatt margin in these curves to meet WECC criteria.

MR. JERRY SMITH: The data point that seems to be highlighted on this particular plot is at a voltage of .933 per unit, and minus 23.2 megavars. Is .933 per unit the maximum voltage deviation that can be accommodated per WSCC criteria at this location for this outage?

MR. DEISE: It doesn't specify a number for that. It just specifies that you must have been at zero. It doesn't specify what the voltage would be in the criteria.

MR. JERRY SMITH: Thanks for that tutorial. Appreciate it.

We heard Paul Smith explain how APS' reserve requirement for local generation purposes was established, and that was identified as 190 megawatts. When I looked at the reserve requirements for the Phoenix area in general, it ranges from 503 to 866 megawatts. Does that mean the difference in those two numbers is someone else's obligation, reserve obligation?

MR. DEISE: Yes, it takes a look at the whole valley, what the valley would need.

MR. JERRY SMITH: And is the same criteria used to establish the total valley reserve requirement that was used for APS units.

MR. DEISE: Yes, it was.

MR. JERRY SMITH: Let me turn our attention now to the alternative mitigation measures that you looked at. One was 600 megavars SVCs --

MR. DEISE: Yes, sir.

MR. JERRY SMITH: -- that you priced out here for us. You mentioned that APS and SRP have already committed to 600 megavars of chunk compensation at Ocotillo and Kyrene. What caused you to select as an alternative 600 megavars at Kyrene and SVC as a potential mitigating measure? Was there any rationale in terms of the 600 megavars for the SVC?

MR. DEISE: The study showed it came close to alleviating the RMR, I think it came to 452, so it seemed it took the most effective of what we look at.

MR. JERRY SMITH: It added 452 megawatts to the SIL, which brought you up to the load-serving, to the peak load requirement for the valley.

MR. DEISE: I believe it goes past that.

MR. JERRY SMITH: Okay. You described how what was needed was something that could respond to an outage rather than something that would be normally open and a base condition.

MR. DEISE: Yes.

MR. JERRY SMITH: If 600 megavars is

something that needs to be responsive to the outage and not on in a base case condition, is that reflective of what could also be accomplished by var supply from local generation units.

MR. DEISE: Yes.

MR. JERRY SMITH: So if we had sufficient units on, and I believe the time period of this analysis was 2005, if we had sufficient local generation on so that we had 600 megavars of var capacity from local units, that should accomplish the same purpose?

MR. DEISE: Yes, it would. I hope we wrote in there somewhere that that was true. If I didn't, maybe it was in an earlier section that we talked about RMRs and so forth. But certainly any other unit would do that.

MR. JERRY SMITH: If that is the case, is that representative of the local generation required to mitigate the RMR condition to increase it to 452 megawatts?

MR. DEISE: No. I think you have to go back to the -- well, you'd have to go back, I'm sorry, I forgot the number for APS, but whatever that number is for APS, it's what you're going to need if you're going to look at the load curves we're doing. Give me just a second. You're talking about RMR, you're talking above the SIL,, I thought.

MR. JERRY SMITH: Maybe I should have asked.

MR. DEISE: No, you need to -- we don't want to mix up technical and economics. But if you go back to the way we've defined RMR, you need between 835 and 1,024 between '3 and '5. That would alleviate RMR on Page 6.

MR. JERRY SMITH: What page?

MR. DEISE: Page 6. This is very close to what you called your score card. The only thing that's missing is the minimum amount of generation.

MR. JERRY SMITH: I was assuming that probably the conclusions that you're referring to were based upon some dispatch models that may not have been focused on establishing the minimum number of local units and minimum generation to mitigate the RMR condition. I mean --

MR. DEISE: I'm not sure what you did, but we didn't try to find the minimum amount of units that were required. We did a sensitivity on the units that are around.

MR. JERRY SMITH: And we have established through our prior questioning that some units are more effective at mitigating than others.

MR. DEISE: Yes, that's true.

MR. JERRY SMITH: To the degree that you had a sufficient number of those units at the right locations to achieve 600 megavars, an equivalent 600 megavars that this chunk var compensator would provide, you would have achieved the same purpose?

MR. DEISE: Yes, if I understand your question right. The vars don't matter whether they're coming out of SVC chunk capacitor or megavars. If you've got the same location, flow of miles is not going to look at them any different.

MR. JERRY SMITH: The conclusion that you just referred to about the 600 megavars resulting in 452 megawatts of increased import capacity, is that just for APS or is that the Phoenix area?

MR. DEISE: I'm going to have to look to my colleagues. I don't remember now. Is that for the whole valley or just APS' share, Pete?

A VOICE: It's for the whole valley.

MR. DEISE: His response was it was for the whole valley.

MR. JERRY SMITH: So when you did your comparative cost production and generation cost savings, you were assuming that APS could take advantage of that full benefit?

MR. DEISE: Again, when you look at the cost, you remember how we do those, we do that with an economic dispatch of the GE maps, whatever. It finds the cost difference. When you look at the capacity factors you see that it's the APS units moving, backing off, so the units are in the APS, predominantly, you're not backing off Salt River for this.

MR. JERRY SMITH: Since we've started getting into a discussion about dispatch, let's talk a little bit more about that in the map simulation.

What type of dispatch assumptions are made relative to APS versus SRP units versus Pinn West units as you look at modeling the local generation in those studies?

MR. DEISE: The GE maps doesn't care about ownership of them. It's looking at the heat rate curves you've given them, and the fuel cost. Because that's the bulk of what they're talking about in any variable O&M you've given.

What it does, it doesn't look to see whose units are being dispatched, it takes all the load and finds the cheapest units to run. That's what the GE map does. It doesn't say look, APS, you've got to, in one hour, generate 600 megawatts. It doesn't worry about that. Just make sure the load is met. It's a one-world concept for WECC.

MR. JERRY SMITH: So you're saying for the studies that have been done for comparative analysis, the dispatch model is one that assumes, on an economic dispatch, all of the units in the west?

MR. DEISE: Yes, sir.

MR. JERRY SMITH: So as you have need for more generation locally, it will dispatch the most economical unit, provided there's not a transmission constraint that impedes that?

MR. DEISE: That is correct. So if we're looking at the load's going to move 100 megawatts for APS, the dispatch goes out and finds the most economic 100 megawatts. It doesn't say what the most APS, the most in WECC, moves that up to 100, makes sure there isn't a transmission constraint and you're done. So it does look at all units, whatever the most economic one.

MR. JERRY SMITH: The dispatch modeling that was done for this case, to look at APS' mitigation of RMR, did it apply that same dispatch assumptions to the SRP load and units?

MR. DEISE: Yes.

MR. JERRY SMITH: Is that a model that all the study participants agreed was a reasonable representation for what would actually occur?

MR. DEISE: I'm not sure what you mean by all the participants, since APS did the study.

MR. JERRY SMITH: Let me ask, who were the participants in the study that you're reporting on.

MR. DEISE: We may be splitting hairs, but we worked with Salt River Project, Tucson Electric, and Western Area. We reviewed the assumptions they were using and they did agree to the assumptions that were being used in the study. Does that make them a participant, maybe we're splitting hairs.

MR. JERRY SMITH: You've heard some comments about the collaborative process of the utilities here, excluding nonutilities with Staff's support as we went through this process. I think it's important for us to establish to what degree this was or was not a unilateral study by APS, and that's why I was trying to...

MR. DEISE: Again, to make it clear, we did not work with the other marketplace, that are nonTOs. We worked with Western, Salt River Project, Tucson Electric Power.

MR. JERRY SMITH: And those parties agreed with the assumptions of the model?

MR. DEISE: We worked with them on the model and the results that made technical sense, yes, sir.

MR. JERRY SMITH: One of the things that I think is prevalent in your report in the Phoenix area, and it also carries over to all of the other studies that we've had presented to us today, is there's lack of detailed documentation about the dispatching model assumptions, and the economic assessment assumptions, and I would request that in the future, that information would be most helpful in supporting the facts that are presented in these reports.

In particular, one of the things that sort of came out in my look at the alternative comparisons, as you looked at a short three-year window on potential resource benefits of going to the market by resolving RMR constraints with an expenditure that you're saying is hard to justify, and those expenditures are for facilities that will have a 30- to 40-year life economically, and yet you're trying to compare the economic benefits of only a two- to three-year period with the annualized cost of that larger capital investment, and to me, that seems to be, it's easy, as in the Yuma area, the payback of that capital investment was achieved in a three-year period. But I do not find it necessarily onerous if the payback period is considerably longer than that to ensure that we have a competitive market that results in cost benefits to consumers.

MR. DEISE: I believe we can agree to disagree on that. I don't think you would be investing money that takes you 25 years to break even.

More important, Jerry, I think part of the problem we have is you did a three-year study. It's hard to talk about advancing and present worthing on stuff that's three years. I think the concept of what you wanted there will work better when we start doing a 10-year.

Even though I disagree with your conclusion there, I think part of the problem is you did the three-year analysis, and you're trying to make long-term decisions out of that. I'd like to think -- and next year is going to be, I think, a lot more complicated, when you start looking at -- let me back up.

Part of the problem is there aren't a whole lot of alternatives. There's not a whole lot we can get done by 2005. When we start talking next year you're doing a study in the year 2010, '11, '12, '13, there's a lot of alternatives then. I see this wasn't thick enough for you. I think the alternative section would be much larger next time because there's a whole lot of different things that you can evaluate in that time frame. So I think it's more of a weakness of just doing a short-term analysis and trying to make long-term conclusions from it.

MR. JERRY SMITH: I think we are in agreement with that general perception, Mr. Deise. I just wanted to make sure that as we do move forward that we don't take a very shortsighted assessment as a decisionmaking device when what we're really after is understanding the long-term implications. And as we look in your study to be done by January of next year, that's what we would be searching for as a content of the report.

I guess I would conclude my questions and comments by taking us back to our network model again, and looking forward to the next study. I am assuming, based upon what we have filed at present, and parties' 10-year plans, that we would be talking about a new delivery point in the form of a southeast valley import location --

MR. DEISE: Yes, sir.

MR. JERRY SMITH: -- for the Palo Verde/Southeast Valley line.

MR. DEISE: Yes.

MR. JERRY SMITH: We would be talking about a Table Mesa import to this area?

MR. DEISE: That's correct.

MR. JERRY SMITH: And what we haven't mentioned earlier today, previously today, is as a part of that Palo Verde to Table Mesa 500 kV line, APS' plans show a TS-5, is it?

MR. DEISE: Yes, sir.

MR. JERRY SMITH: That would become another delivery point?

MR. DEISE: That's correct.

MR. JERRY SMITH: As we look forward to those new import delivery points, is it fair to assume that the Phoenix area load for APS will take in what is today your north valley system and your west valley system as we look at this import assessment?

MR. DEISE: I don't know exactly how that's going to shake out, but yes, we'll show those 230s, and we'll have to determine where we need to cut these to find the reasonable limitations on the system. I don't know what those are now, but that would be correct.

I would even go further and say there may be some impact with the Pinal West substation, if it ties into TEP's 345, and APS has plans of 230s out of there, and there may be some impact there.

MR. JERRY SMITH: I would agree with that.

MR. DEISE: There's a lot that, like I mentioned earlier, there's a lot that can be happening as early as 2006, and certainly 2010 time frame. And that's why, if you will, I gave my little admonishment about the sensitivity of generators. You may see a whole different picture of what generators do. Those that we said have no value in this study may come back next time and have a lot. Again, it's driven by the critical outage and what the system limitation is.

MR. JERRY SMITH: I'll conclude my remarks regarding your study, then, by saying I think I would judge the effort that we've seen not only in your Phoenix area study but the Yuma study and the two other studies that we've had reported to us today as an excellent start at trying to address the RMR import constraint areas in the state, and I am pleased that the parties have taken the steps that they have to file the studies with very short lead time for this particular filing, and it's from that short lead time that Staff has been less assertive about our expectations of what we wanted the studies to address.

But I do want you to be aware that as we move to the next round of RMR studies, that we would like the parties to be more focused on answering the detailed questions that are contained in the study plan documented in the biennial transmission assessment, and among those are some things that have not been addressed effectively today, such as the minimum generation required to resolve the RMR constraint, a better assessment of the comparison of alternatives, and associated economics.

And again, I want to make sure that the parties that have performed the studies and have participated understand Staff is very appreciative of what you have provided us today, and it will be very helpful as we move forward in Track B. Any other questions?

MS. TURNER: Becky Turner with TECO Power Services. One question I have, Cary, is just clarification. On Page 13, Slide 26 of your presentation --

MR. DEISE: Just a second, Becky.

MS. TURNER: The capacity factors that are given for total Phoenix, does that include all of the SRP valley generation, APS valley generation, and the Pinnacle West?

MR. DEISE: Yes, ma'am it does.

MS. TURNER: 7.8 percent is capacity factor for 2004, all that generation?

MR. DEISE: All that generation.

MS. TURNER: The second question was on Page 10 of your report, on No. 4, that conclusion that you draw there.

MR. DEISE: Yes.

MS. TURNER: If you look on Page 29 on Table 6-B, if I am interpreting that table right, it appears that there's like a thousand megawatts in 2003, and 775 megawatts excess capability; is that correct?

MR. DEISE: Yes, ma'am.

MS. TURNER: So that's --

MR. DEISE: This is the total valley. Maybe I didn't make it clear, but this is from an APS perspective of our needs.

MS. TURNER: This is just APS, not total.

MR. DEISE: Yes.

MS. TURNER: Thank you, Cary.

MR. JERRY SMITH: Anyone else?

MR. MOYES: Again, as I mentioned earlier, we probably have a lot of questions but we won't ask most of them, but we do have a few. And I'm going to turn the microphone over to Ken Saline of K.R. Saline & Associates, who is the transmission technical consultant for PPL. And Jerry, we appreciate the questions that you asked, and Cary, the answers that were given, and they have helped eliminate a lot more of our perspective on the situation, and we will ask a few questions, and then the further lead to hopefully written comments, and as I mentioned earlier, hopefully some ongoing dialogue with APS and your staff as is feasible.

MR. SALINE: Cary, one of the questions that I think -- I'd like a little explanation on is we've been using the word deliverability and load-serving capability. Can you tell me the difference, just so I have an understanding?

MR. DEISE: I'm going to use it in the context we've been using here in the competitive models, if you will. To me, when we're talking about deliverability, we're talking about the transmission that is capable of coming from the outside interconnections to the valley. By that I mean the transmission from Palo Verde to Westwing, from Navajo to Westwing, Four Corners to Pinnacle Peak. That's what I call deliverability, someone who is delivering to the outside of our system.

When we're looking at RMR, we're looking at what you can do inside the valley, and I separate those as different.

MR. SALINE: And load-serving capability?

MR. DEISE: To me it's basically the SIL plus what the generation is. Strictly speaking, you'd have to go to the curve because it's not exactly a one for one, but you would go to the curve, look at what the generation is, go up and you'd read what the load-serving capability is. That's what I call the load-serving capability. The load-serving capability with no generation, we're calling SIL. With generation less reserves, we're calling MLSC. That's the three definitions, the way I look at it.

MR. SALINE: The next question I have is with regard to Table 2 and Table 3 on Page 21, and the purpose of these questions is just to try to understand your studies, and how these numbers were determined.

In Table 2, for example, Agua Fria, you have 110 megawatts in that case. Would you explain how that study was performed or how the numbers were adjusted?

MR. DEISE: What we do is we raise the generation. There's a couple ways to look at it. Basically, you can look at it as raising the generation and shipping that power out, if you want.

That's one way to go. By doing that, you create a backflow which allows you to bring 100 back, if you will. So you're doing that, plus you're finding that there's some voltage support that allows you to serve even another 10 megawatts. So what these are doing is for the ones inside you're taking credit for that back schedule, if you will, then whatever additional vars, what you get out of the units.

MR. SALINE: In Table 3, where was the -- I assume Table 3 was scheduled to Las Vegas or some other area.

MR. DEISE: We split that up because we found that you could serve more load. So what we're basically doing is we've got 35 coming to the valley and the other 65 is going on to Las Vegas.

MR. SALINE: So that's kind of the way the flows are divided, then. I'm having trouble understanding if Table 3 was scheduled into the valley,.

MR. DEISE: 35 of it was. That's different than the incremental costs where we compared everyone equally on 100 megawatts. This study here is back to the nose curves saying you could put 35 more megawatts of load-serving capability in the valley.

MR. SALINE: Let me state it my way and see if you agree with this. If Sundance were generating and delivering 100 megawatts to an APS load inside the cut plane, then it would increase the import capability by 35 megawatts?

MR. DEISE: That's true.

MR. SALINE: I think just for informational purposes, the inconsistency here, because of where these certain plants were located inside and the other ones are outside, we're getting 100 megawatts added to the contributions on the Table 2 numbers, and there's not this 100 megawatts. So in the future, I think it would be beneficial to see maybe all of them consistently affecting the same load, either inside or in Las Vegas or both, just so if there's 100 megawatts scheduled to a load inside the cut plane, and you get a 35 megawatt increase, you see 135 impact on the cut plane.

MR. DEISE: We'll try to improve. We're trying to split this thing out for you. Again, I'm trying to show you the incremental so you see the impact to the plant. Part of the problem is that if I increase the valley 100 and Sundance at 100, the nose curve doesn't work. It falls apart. If voltage collapses, how much can we keep going back? If he added 35 megawatts, it doesn't have to be Vegas, go out on the system anywhere but the valley, that works. That's why we're saying there's a 35 megawatt. We can probably improve on painting that picture a little better. We'll work on that.

MR. SALINE: We're still trying to understand how 2 and 3 are different. I think they are different, but in some ways the bottom line that we're trying to understand is whether or not it has a positive impact on the import capability, and we believe the table says it does.

MR. DEISE: Yes, it does. I'm sorry, it doesn't come clear. It does say that Sundance has a positive impact on the load-serving capabilities. Yes, it does.

MR. SALINE: Have you examined these similar tables for the entire APS and SRP cut plane?

MR. DEISE: These are all the units in the valley in Table 2, we did all those.

MR. SALINE: I guess when I'm looking at these, and you're looking at some sensitivity in the west valley, for example, around the West Phoenix area, I'm curious if there's also some voltage weaknesses out in the east valley for which Sundance would have a higher contribution towards, and West Phoenix being further away, in that instance might have a lower contribution towards.

MR. DEISE: I'm trying to think of -- I'm not sure of your question there.

MR. JERRY SMITH: Mr. Saline, are you suggesting for a different contingency than what these studies look at?

MR. SALINE: I guess, yeah, I'm asking if there were load sensitivity in the SRP area or the APS area, if the contributions from each plant to each area would have a different factor.

MR. DEISE: I think one way, thinking out loud here, but you can see one way to look at it is to subtract 100 megawatts from West Phoenix that you're getting for going outside, and you're getting 34 then from voltage support. I'm just thinking off the top of my head. I would think West Phoenix is about the same as Sun Desert to the east valley, so I would say yeah. I haven't thought about that before, but I would say they look very comparable. I thought the numbers all looked comparable. As you go to Desert Basin, which is a little further south, you don't get as much.

So I haven't done the exact analysis what you said, but I think if you subtract 100 off the top, that's what it's telling you, what your comment was about the closeness to where the voltage problem was.

MR. SALINE: Correct me if I'm wrong, but it's my understanding these are increases in the total system import capability between APS and SRP.

MR. DEISE: Yes. We didn't allocate these out, we're doing a sensitivity.

MR. SALINE: Another question. The limitation's based upon the voltage stability; is that correct?

MR. DEISE: Yes, sir.

MR. SALINE: So if you have plans outside of this cut plane that have a positive influence on the import capability, does that indicate there's another cut plane that should be examined further out?

MR. DEISE: I don't think that follows from that, no.

MR. SALINE: I'm thinking for a voltage stability standpoint if you have plans outside of this arbitrary cut plane, that influences.

MR. DEISE: I don't think it's arbitrary. I think it does show what the APS valley loads are.

MR. SALINE: Those are my words. But if you have a voltage stability problem inside the cut plane and you have a plant outside the cut plane that's improving the voltage stability problem inside the cut plane, I'm asking if that suggests there might not be another cut plane that should be examined for valley-wide transmission purposes.

MR. DEISE: I don't think. So it might tell you you will need to know whether that plant is on or off if you want to use that additional import. I think that's what it tells you, I don't think it has anything to do with what the cut plane is.

MR. SALINE: This is probably just a comment. You indicated in the future you're going to include City of Mesa's loads, and I assume that these are all electrical loads, not contract paths?

MR. DEISE: Yes.

MR. SALINE: Then there's a myriad of electrical districts that have load, and the Surprise substation, and around Agua Fria, and the east valley, all throughout SRP's area. And in the instance where you're going to include Mesa, it might also be appropriate, because those are imports from Western's system also.

MR. DEISE: Okay. On Mesa, we haven't said exactly what we're going to do, quite frankly, since it is over on Salt River's side they need to take the lead how to put that in, we need to work on how best to do that.

MR. SALINE: There's Maricopa Water District, RIDED, and a few ones. These things are expanding out and becoming in the circle.

MR. DEISE: Especially when we build in the west valley 230 Jerry spoke about. We need to pay attention to those.

MR. SALINE: At that point in time do you envision Western having an allocation of cut plane capability?

MR. DEISE: I don't envision it, but again, when we go to next year's I would have an open mind, we'll see what comes out of it, whatever makes sense. But some things we'll have to change a little bit, or I'll have to figure out how to do it better with them.

Again, I don't think Western moves the RMR demand energy or hours, but if there's a better way of representing it so people have a comfort level, we need to explore that next year.

MR. SALINE: The next question I have is regarding the operation of your systems, regarding the import limitation numbers, I understand how they're developed, but when APS is dispatching its units, do you dispatch to your limit or do you and Salt River Project coordinate so that you're both operating all of your plants coincidentally towards the combined limit?

MR. DEISE: We manage to the combined limit for operational purposes. We'll do it in the off seasons, all summer, but in the summer every morning we exchange, or every afternoon, we exchange tomorrow's load forecast and generation schedules within the valley. We give them ours, we compare that to a total curve to make sure there are no issues with the import tomorrow. So from an operational viewpoint we look at it that way.

MR. SALINE: Is it safe to say on occasions there's times when SRP exceeds their allocated amount and there's times when APS exceeds their allocated amount?

MR. DEISE: Yes, there is, on an operational basis, but we never exceed the total for operating period.

MR. SALINE: I think that's all we have.

MR. JERRY SMITH: Thank you, Mr. Saline.

As we conclude today, I think it might be appropriate for Staff to respond to PP&L's question about what are we going to do relative to keeping the record open, and the process as we move forward.

The reports that we have reviewed today are filed with the Commission in our biennial transmission docket. We will be putting out on our website the presentations that have been given today. We would request that any party that wants to provide written comment regarding these RMR studies, to file those as part of our record in the biennial transmission assessment docket. That would be most helpful, I think, to the utilities, to have that foundation of information as they start trying to prepare to do the next round of studies.

And I'm going to, for now, leave open-ended the question of how the next RMR study will proceed, and I will be meeting with the utilities to discuss in greater detail how we might benefit from improvements in study modeling or our participation of others, and once we have that discussion, Staff will respond on the record in the biennial transmission assessment for all of the parties to know how we will be proceeding on a forward-moving basis.

The one other matter that I need to attend to today is that the results of today's RMR study presentations, including information that we have requested the parties provide us that were not included in today's material, will be factored into an update of the Track B, Exhibit B, contestable load. It is my hope that we can get that accomplished in time for the open meeting on the 21st. But since some of that data is not in my hands, I am not necessarily in control of the date which that will be available. But at least that would allow the parties to have a sense of where Staff views the contestable load. It hasn't migrated as a result of these RMR studies.

Are there any other comments or questions of these proceedings?

(No response.)

MR. JERRY SMITH: If not, I propose that we close our meeting and thank you for your attendance and your participation.

(The special open meeting workshop concluded at 2:37 p.m.)

STATE OF ARIZONA)
) ss.
COUNTY OF MARICOPA)

I, CECELIA BROOKMAN, Certified Court Reporter No. 50154 for the State of Arizona, do hereby certify that the foregoing printed pages constitute a full, true and accurate transcript of the proceedings had in the foregoing matter, all done to the best of my skill and ability.

WITNESS my hand this 25th day of February, 2003.

Cecelia Brookman

CECELIA BROOKMAN, RPR
Certified Court Reporter
Certificate No. 50154

Attachments

WELLTON-MOHAWK GENERATING FACILITY'S INITIAL COMMENTS TO THE APS JANUARY 31, 2003 "RELIABILITY MUST-RUN ANALYSIS 2003-2005"

February 14, 2003

Prepared by Navigant Consulting, Inc.
201 E. Washington Street
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A. INTRODUCTION:

Wellton-Mohawk Generating Facility ("WMGF") provides its comments to Arizona Public Service Company's Reliability Must-Run Analysis 2003-2005, dated January 31, 2003 ("APS RMR Study"). WMGF's comments are provided based upon the results of an independent review of the APS RMR Study conducted by Navigant Consulting, Inc. ("NCI"). At this time, WMGF's comments are only initial in nature because NCI has not had the opportunity to: (1) review certain important supporting materials to numbers and conclusions stated in the APS RMR Study; or (2) verify APS' analysis through NCI's own analysis. NCI intends to perform both of these functions upon receipt of materials requested in its data request to APS, which is included as Attachment 1 to this initial report. As of February 14, NCI has discussed its data request with APS and the Arizona Corporations Commission ("ACC") staff and APS has provided some of the requested information to NCI either orally or in writing. After the aforementioned review and verification functions have been performed, WMGF will make further comments to the APS RMR Study.

B. WMGF's COMMENTS

1. NCI's review of the APS RMR Study reveals that the peak demands for the Yuma area shown in Table ES4 on page 8 of the APS RMR Study are 308 MW, 312 MW, and 324 MW for 2003, 2004, and 2005 respectively. In APS' November 13, 2002 response to WMGF's data request RK1.1 in the Track B proceeding, APS stated that the peak demands for the Yuma area were 303 MW, 322 MW, and 330 MW for 2003, 2004, and 2005 respectively. Even though these differences are relatively small, APS has provided no information in the report on why the estimated peak demands have changed. It should also be pointed out that the peak demand forecast for the Yuma area provided in the aforementioned data request response was different than information presented by APS in its review of the Yuma load pocket in mid-2002 when it showed peak demands for the Yuma area of 323 MW, 335 MW, and 344 MW for the same three years.

2. The APS RMR Study does not clearly indicate whether it included loads served from the radial 69-kV line which extends northward from North Gila to Senator Wash or from a 69/34.5-kV loop between the Gila and San Luis substations. In addition, the RMR study prepared by the Western Area Power Administration ("Western") does not apparently give consideration to

the impact that these loads could have on RMR requirements. WMGF believes that loads served from these circuits could be as high as approximately 20 MW. Due to the way these loads are interconnected with the APS grid at North Gila and San Luis, WMGF believes they should be reflected in the APS RMR Study and, if they are reflected, APS' RMR requirement could increase by approximately 10-20 MW.

3. APS indicates at several places in the APS RMR Study (e.g., page 44) that a second 500/69 kV transformer could be added and provisions could be made to allow contingency sectionalizing of the 69-kV bus at North Gila to increase imports into the Yuma load pocket and mitigate a portion of the Yuma RMR requirement. It should be noted that these potential additions and modifications were not mentioned in APS' Ten-Year Plan for the 2003-2012 period, nor have they been discussed in previous proceedings on the RMR issue. The APS RMR Study does not state why these potential additions/modifications have just surfaced and does not provide the basis for the $3.5 million estimated cost of the transformer and associated equipment, which appears to be markedly low.

4. The APS RMR Study results seem to imply that the impacts of an outage of the North Gila 500/69-kV transformer and of the North Gila 69-kV bus on the System Simultaneous Import Limit ("SIL") are the same. This result does not seem reasonable to NCI because there is still a 69-kV tie to the higher voltage system in the area (via the North Gila-Gila 69-kV line and the Gila 69/161-kV transformers) after an outage of the North Gila transformer whereas an outage of the North Gila bus opens all ties to the high voltage system. Subsequent discussions with APS have indicated that, in fact, the 69-kV bus outage is the most limiting.

5. The APS RMR Study only lists the above outages as being critical. The RMR Study does not state whether or not APS considered the impacts of outages of the 500-kV lines interconnected at North Gila; particularly the Hassayampa-North Gila line, which also appear to be critical transmission components. Discussions with APS have indicated that for the conditions modeled in the studies the 500-kV outage is not critical. NCI will be conducting studies of other operating conditions (such as with maximum generation at the Blythe Project and with proposed new generation in the Imperial Valley on line) to assess if an outage of this line is critical. If it were found to be a limiting outage, the RMR mitigation value of installing

the additional 500/69-kV transformer at North Gila would likely be greatly reduced.

6. The APS RMR Study on page 11 says that the non-APS owned generation in the Yuma area (i.e., the 75 MW unit owned & used by the Imperial Irrigation District (IID) and the 53 MW Yuma Cogeneration project being sold to SDG&E) are resources that could be available to APS to provide the utility RMR support. The RMR Study, however, does not say whether APS intends to enter into the required contracts to ensure that these resources will be available and running when required to provide RMR support to serve APS' customers. Without the existence of such contracts, these resources cannot be relied upon to provide RMR support and thus must be removed from the list of available alternatives.

7. In the APS RMR Study, the utility performed an RMR energy calculation for the Yuma area. The RMR energy calculation shows that energy is needed from RMR capacity at about a 30% capacity factor. The RMR Study, however, does not show how APS intends to meet this requirement when its only generation in the load pocket is the four peaking units at Yucca.

8. The APS RMR Study notes that the utility has a 70 MW reserve requirement for the load pocket, but does not explain how the number is derived nor how or if this reserve requirement changes over time. APS has agreed to provide information on the derivation of the reserve requirement.

9. The APS RMR Study states, "All existing Yuma-area transmission and generation resources are necessary to reliably serve the Yuma-area load" (Page 11). This statement is not accurate. Generation could be added in or on the periphery of the load pocket to replace at least some of the Yuma-area generation resources in a manner that would provide the same or higher levels of reliability. For example, if APS were to enter into a contract to purchase power from the WMGF, at least some of APS' Yuma-area generation could be shut down without impacting local reliability.

This concludes WMGF's comments to the APS RMR Study based on the information known at this time.

ATTACHMENT 1

Wellton-Mohawk Generating Facility First Set of Data Requests To Arizona Public Service Company Regarding Reliability Must Run Analysis 2003-2005 (January 31, 2003)

WMGF 1.1: Please provide Appendices A, B, C and D referenced in the subject RMR study.

WMGF 1.2: Please provide a list of all contingencies considered in the studies performed for the Yuma area and information on remedial action schemes or special protection schemes utilized during the contingencies.

WMGF 1.3: Please provide a copy of the power flow data sets used for the Yuma area studies.

WMGF 1.4: Please provide information on the derivation of the 70 MW reserve requirement for the Yuma area.

WMGF 1.5: Please provide information as to how the IID combustion turbine interconnected to the Yucca 161-kV bus was dealt with in the Yuma area studies.

WMGF 1.6: Please provide information on APS' 10-Year plan for the Yuma area 69-kV system to the degree that such plan contains information not listed in Table 4 in the RMR study.

WMGF 1.7: Please provide information as to how the loads served from the Gila-Sonora-San Luis 69/34.5-kV loop were dealt with in the RMR study. If loads on this system are not included in the Yuma area peak demands shown on Table ES2, please provide all reasons why they are not so included.

WMGF 1.8: Please provide information as to how the loads served from the North Gila-YPG-Senator Wash line were dealt with in the RMR study. If loads on this system are not included in the Yuma area peak demands shown on Table ES2, please provide all reasons why they are not so included.

WMGF 1.9: Please provide all information to support the conclusion on page 7 of the report that the Simultaneous Import Limit (SIL) into the Yuma load pocket is 164 MW.

WMGF 1.10: Please provide all information to support the conclusion on page 44 of the RMR study that addition of the 500/69 kV transformer will increase the SIL by 110 MW.

WMGF 1.11: Please provide all information to support the cost estimate for the 500/69 kV transformer and supporting equipment at North Gila of approximately $3.5 million appearing on page 44 of the RMR study.

WMGF 1.12: Please provide all reasons why the RMR study states as one of its conclusions that the 75 MW IID steam generator at the Yucca substation and the 53 MW YCA cogenerator located near the Riverside substation are resources that may be used to meet APS' unmet RMR need when these resources are committed to loads outside the Yuma load pocket.