BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: : Docket Number

MIDWEST INDEPENDENT TRANSMISSION : ER06-1099-000

: ER06-1099-001

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Hearing Room 4
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC
Tuesday, September 26, 2006

The above-entitled matter came on for technical conference, pursuant to notice, at 9:00 a.m.

BEFORE:

LAUREL HYDE, Ph.D., FERC
SENIOR ECONOMIST

APPEARANCES:

GERALD G. FARRINGER
CHRISTOPHER C. CARPENTER
M. BRYAN LITTLE
DANIEL M. MALABONGA
KEVIN M. MURRAY
MICHAEL KESSLER
RICHARD DOYING
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-- continued --

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P R O C E E D I N G S

(9:10 a.m.)

MS. HYDE: If everybody could take a seat, good morning, everyone, I'm Laurel Hyde, and I'm an Economist in the Office of Energy Markets and Reliability in the Central Division.

On behalf of the Commission, I want to extend a warm welcome to all of you. As you know, this tech conference is intended to address Midwest ISO's filing in Docket Number ER06-1099, regarding proposed shortage and emergency procedures.

As specified in that Order, the purpose of the -- the proposal filed here was scheduled for a technical conference. The conference is intended to provide the Commission Staff with a better understanding of Midwest ISO's proposal.

The purpose of this conference is not for the parties to engage in arguments over the pleadings filed or statements made earlier in the proceeding or during this conference, but, rather, to let Staff clarify the facts presented.

Time permitting, we will allow intervening parties to ask clarifying questions to the Midwest ISO.

Written comments will be permitted from all parties, after this conference, and must be filed by October

12th, with reply comments due by October 19th. We're trying to keep this moving rather quickly.

The conference today is scheduled from 9:00 to 4:00. Before lunch, we hope to get through Staff's questions regarding technical matters that are not price related and not financial issues.

After lunch, we plan to ask questions regarding pricing and RSG effects. We expect to take a short break, both in the morning and in the afternoon. We'll just play it by ear and see how we're going, timing-wise.

It's important to note that anything said by Commission Staff members here today, doesn't necessarily represent the views of the Commission or Commission Staff, generally.

Thus, any statements made during the conference by Commission Staff, should not be attributed in any way to the Commission, or be considered to bind the Commission to any position or outcomes.

Does anybody have any questions, just on this general --

(No response.)

MS. HYDE: Okay. It seems like it would be a good idea to start with some introductions.

Again, I'm Laurel Hyde.

MR. MERONEY: I'm Bill Meroney with the Policy

Division.

MS. MENZIES: Hi, I'm Rebecca Menzies. I'm with the OMER.

MR. CALLAHAN: I'm Joe Callahan with the Reliability Division.

MR. HULL: I'm Lloyd Hull with the Reliability Division.

MR. GREENFIELD: I'm Larry Greenfield with the Office of General Counsel.

MS. HYDE: And Melissa Nimit is also with the Office of General Counsel. She'll be back shortly.

MR. DOYING: Richard Doying, Midwest ISO.

MR. PATTON: David Patton, the Independent Market Monitor for the Midwest ISO.

MR. KESSLER: I'm Michael Kessler of Powell Goldstein, on behalf of the Midwest ISO.

MR. TROXEL: Greg Troxel, Midwest ISO Legal Department.

MR. GARDNER: I'm Joe Gardner, Midwest ISO Operations.

MR. JETT: Bill Jett, Duke Energy.

MR. MURRAY: Kevin Murray, representing Coalition of Midwest Transmission Operators.

MR. LITTLE: Brian Little, on behalf of Consumers Energy.

MR. FARRINGER: Jerry Farringer, Consumers Energy.

MR. MALABONGA: Daniel Malbonga, on behalf of Midwest ISO.

MR. BOURBONNAIS: Bill Bourbonnais, WPS Resources.

MR. HEGEDUS: Mark Hegedus, Spiegel & *McDiarmid,* for the Midwest TDUs.

MR. BODNER: Mike Bodner with Excel Energy.

MS. HYDE: Okay, thank you very much. I think that what will be useful to start with, is to have the Midwest ISO do a short presentation on what this proposal is about.

I noticed that we've got two different sets of paper here. It looked to me that the second on Market Power Mitigation, would be better to hold until this afternoon, and if you could just present what you have on the other, that would be very helpful, and maybe get this all kicked off. Thank you.

MR. KESSLER: Thank you, Laurel. Again, I'm Michael Kessler, on behalf of the Midwest ISO.

We prepared just a short overview of what the proposal was, that I'd like to run through, to get our discussions started today.

Joe Gardner and Richard Doying will join me in that presentation of the materials. I know you wanted to address pricing issues later in the afternoon, but our initial presentation deals with both the operational and pricing, so --

MS. HYDE: That's fine.

MR. KESSLER: -- if we can go through the whole thing this morning, at least it will set the background for our discussions.

(Slide.)

MR. KESSLER: I think everybody should have a handout here, and the first slide really just gives you an overview about the topics we would like to discuss, including the purpose of changes that were presented to the Commission in this docket, an overview of how the proposal will work, the reliability impacts, pricing issues.

We'll address the RSG secondary implications of the proposal, the demand response. Dave Patton, Dr. Patton, will address market power mitigation this afternoon, and then, obviously, a discussion period.

(Slide.)

MR. KESSLER: These were the topics that are at least generally set forth in Attachment B of the Technical Notice, and we tried to incorporate at least a general response to those issues in the presentation materials.

(Slide.)

MR. KESSLER: Just by way of background, our proposal was initially filed on June 5th of 2006, in Docket ER06-1099.

We amended the proposal on June 7th, to specify an effective date, one day after notice was provided to FERC, that necessary software and system and software changes were in place.

The original June 5th notice had requested a one-day-after-filing effective date, so that request was superceded by the June 7th notice.

We wanted to provide you with an update of the status of those software and systems changes. Delivery is expected of the software patches that are necessary to implement the program, the week of September 25th -- this week.

Once it's installed, it will go into testing. The testing is expected to be complete in early November, and, assuming that all of the testing works out as expected, we would expect that the software necessary to implement the ARC proposal, which is the Step One proposal that was filed, would be ready in mid- to the end of November.

But, consistent with our June 7th filing, we would still provide the Commission with notice of the final implementation date, following testing.

(Slide.)

MR. KESSLER: On August 4th, the Commission issued an Order that accepted and suspended our proposed tariff sheets, and established an effective date, either January 8 of 2007, or as such date may be modified in an Order following the Technical Conference, and, of course, directed the Technical Conference.

(Slide.)

MR. KESSLER: The August 24th Order also requested -- I'm sorry, on August 24th, a Notice was issued, relating to the Technical Conference, and there were two attachments: Attachment A requested certain information be provided by the Midwest ISO.

That information was provided on September 15th, and we are also available to try and respond to any questions you may have about that data.

Attachment B of the Notice identified the issues that are the subject of the Technical Conference.

I'd like to turn it over to Joe Gardner to talk about some of the operational issues relating to the proposed changes, and to respond to some of the questions that were in Attachment B.

(Slide.)

MR. GARDNER: I do better when I'm standing, so, if that's okay, just to give a little bit of background on why we made the changes, first off, there was some ambiguity in the tariff when offline resources should be deployed in 40.2.15.

They were -- the current tariff has them, both in Step One of 40.2.15, and Step Three, so we wanted to resolve that ambiguity.

We were trying to make sure that we got appropriate pricing during supply shortages, and we wanted to get the ability to clearly lay out in the tariff, that we could use a portion of the operating reserves when we were required to maintain reliability, and to help avoid situations from developing into emergencies.

You know, we've learned a lot in the last 18 months since the tariff went into effect and the market went into effect, and we have events, not every day, but, you know, periodically, that we really need to be able to try to use the operating reserves in the manner we're presenting here today in order to maintain reliability. That's really what we're after.

Basically, I'll try to give a little bit of an overview on what the different steps are. And the steps I'm referring to here, are the ones in the revised tariff.

Basically, Step One, we're calling the new adequate ramp capability procedure where we would have the ability to use up to half of the capacity, up to Economic Max, up to Emergency Max, excluding the regulation portion, in order to avoid -- in order to give frequency back or avoid frequency declines.

Then we would have a Step Two that could be used for multiple reasons. Step Two would be used the way it currently would be during a shortage like the week of July 31st when we start getting into just using all of the capacity, and you're slowly getting into it, and you're getting into an emergency situation or a situation where you're going to have to start using operating reserves for perhaps an extended period of time, in order to avoid emergency procedures such as load-shedding.

And so that is, generally speaking, what we're going to try to use Step Two for. Now, it also can be used -- and I think I cover it on the next slide -- but then Step Three is load-shedding, per attachment, which is consistent with our current tariff. We didn't change that at all.

(Slide.)

Just to give people a little bit of a background on when we refer to dispatch max, Emergency Max, and that sort of thing, we have this little picture.

Basically, we have the Emergency Maximum load at the top, and then we have the Economic Maximum limit, and then between that range, are several things:

One is the regulation ability of the balancing authority, and, then, separately, is other capacity, which includes the contingency reserves or operating reserves that are there for unit trips, emergency events, other things like that.

What we tried to do, is show that half of that is being used in ARC Step One.

And Step Two, though we do go into Step Two under A, the reasons we would go onto Step Two, it could be that whole range, could be used, and we'll go into the pricing and that, as well. I think that's the important thing to get off this slide.

(Slide.)

MR. GARDNER: Basically, Step One -- I'll go into a little more detail for each step -- is to address sudden and substantial gaps between abandoned resources.

When we see these things happen, the shift manager in a control room needs to -- believes that we're going to have to have reliability issue if we don't use the operating reserves. They would call the event.

We would -- what we're stipulating here -- and we put in the tariff -- is that we would not use that for more than 60 minutes. It's intended for -- just to give us enough time, use the reserves, until we can get other units online.

So, something has happened; we're short; it's -- we're starting to commit other combustion turbines or other quick-start resources, but it's going to take time to get those online.

In that time, we want to use the reserves to -- for reliability.

When we do release them, we would dispatch in merit order, and they are eligible to set price, and the way we do that, is by substituting for the offer curve, the peaker proxy price that Richard will go into later. Next slide.

(Slide.)

MR. GARDNER: Again, we use it for no more than 60 minutes. We're basically using it because we don't have enough ramp. That's why we call it adequate ramp capability.

That could be because we don't have enough ramp on the units that are online, or it could be that we just don't have enough online, and we don't have enough ramp because we don't have enough online.

But in either case, we don't have enough to ramp, to pick up and maintain reliability.

There are various reasons why this can happen: We can lose several units, none of which are big enough for the control area or balancing authority to call on the reserves themselves; we have several of them happen simultaneously. That's happened.

The biggest impact that we see -- and it happens several times a year -- is, we'll get a TLR curtailment by one of the neighboring reliability coordinators.

There was one event in July of this last year, where we had a curtailment of 1800 megawatts, and we had 15 minutes notice of that, and then we had 1100 megawatts the very next hour, and we had 15 minutes notice of that.

So, we had to respond to an 1800-megawatt loss and an 1100-megawatt loss, pretty quickly, and using reserves would have been a much better way of handling the problem. We wouldn't have had to rely on the control area's regulation and have any impact on the frequency of the unit connection.

Important to note, is that we're not including offline resources here. When we get into this situation, we're calling on resources as quick as we can, to get back to a reliable state, but, in the interim, until those units can come online, we're using the online operating reserves.

We're not proposing in this procedure to use the offline operating reserves.

(Slide.)

MR. GARDNER: Okay, now going to Step Two, basically, these can have -- Step Two is, we can get to Step Two directly, by skipping Step One, if it's a general shortage, a general maximum generation emergency shortage.

Or, we -- the 60-minute timeframe that I talked about in Step One, isn't long enough, we would go into Step Two, or if the amount of generation that we needed, was more than half of the difference between Emergency Max and Economy Max, less regulation.

If we needed more, we would have to go to Step Two. The intent of this step is basically to stay similar to the current tariff provisions, in terms of how they were priced, substitute for the offer curve, $1,000 a megawatt hour.

Next slide.

(Slide.)

MR. GARDNER: All right, we talked about implementable Step One.

And in this Step Two, it is also the step where we would call on offline units that were offered in as emergency-only, as well.

And when we do release the capacity to the dispatch algorithm, it will be dispatched in merit order, at a set price, with the offer curve substituted for that area of the curve, of a thousand dollars.

(Slide.)

MR. GARDNER: Just generally speaking, in terms of -- we believe we have -- the ability for us to do this, is consistent with NERC standards. I've listed several of them here that have to do with reliability, coordination, and what reliability coordinators have under NERC standards. I'm not going to read them to you here.

(Slide.)

MR. GARDNER: And we believe this is -- using ARC for the 60-minute period, is consistent with good utility practice. We're using this capacity for the reasons that it's there.

When balancing authorities lose generation now, they call this capacity for that purpose. In the past, before the Midwest ISO's market started up, if they lost a big schedule from a TLR, they would rely on their operating reserves to pick up to replace the schedule.

That part, we don't have the mechanism right now, because all the schedules come into the market, the market doesn't have a way right now, without the ARC procedure in place, to use the reserves to replace schedules.

So we believe it's consistent with past industry practice and good utility practice, and it's also consistent with NERC standards, in that the NERC standards require replenishment of the reserves in 90 minutes, and we're actually proposing in our procedure, to be no more than 60 minutes. I think that's all, and I'll turn it over to Richard to talk about pricing.

(Slide.)

MR. DOYING: Thanks, Joe. I don't pace as well as Joe, so I'm going to go ahead and stay in my seat.

This is a very high-level overview, and it includes some examples in the back, and the examples are actually simplifications that are for illustrative purposes, and I'll highlight where the actual implementation is more complicated and where the simple illustration is more simplistic than what we'll actually be doing.

We did provide, in response to the questions that you had sent in, the actual equations that we'll be using to calculate the peaker price, and so you've got all that detail, and we can go through that, as well, if you'd like.

The pricing, as Joe indicated, for Step One, when we release that first 50 percent of the range above Econ Max, and below Emergency Max, less the regulation, will be based on a peaker proxy offer price, and actually, it's the higher of that peaker proxy offer, and we'll go into detail on how that's calculated, or the actual offer that's submitted by the generator.

And the reason for that higher pricing, is to assure that the prices that are established in the market, that clear in the market during that period, do reflect the value of the reserves that are released.

Absent that, when you release the capacity, you could actually have prices fall. That's exactly the wrong price signal and elicits exactly the wrong response when you're out of supply in the market.

So, the intent here, again, for Step One pricing, is just to be sure that the segments that we released of the reserves, are priced in a manner that's consistent with the supply scarcity that we're in.

That offer will be calculated daily, and it will be calculated based on the historical peaker offers that we've received, "historical," here, being the previous 30 operating days. We'll use that to derive a heat rate. We'll apply a current gas price to develop the peaker proxy price, and, again, we'll go into more detail on exactly how that works, in a few pages.

And, as Joe indicated, once we've established those new proxy offers for the generators, they will be available within the dispatch system; they'll be dispatched in merit order, and they will be eligible to set LMP.

MR. PATTON: Can I make one comment?

MR. DOYING: Sure.

MR. PATTON: This is David Patton. The other important factor on the higher-of pricing, is that it's likely that some of those reserves that are released, have marginal costs higher than the peaker proxy, in which case, you'd be doing harm to the supplier, to lower their offer and dispatch them at a lower level.

You'd also -- to the extent that's true, you want to dispatch in economic order, with the highest-cost dispatched last, and would want to reduce their offer from what they had submitted.

MR. MERONEY: Since you brought that up, a quick clarification: When you say "in merit order," is that based on the original price in the offer or the substituted price?

MR. DOYING: Based on the substituted price.

MR. MERONEY: So, basically, it's the higher-of.

MR. DOYING: Right.

MR. MERONEY: So that if you have a whole bunch of things you've substituted price for, you're not really differentiating in terms of you're not necessarily dispatching the cheaper offer first?

MR. DOYING: Well, you actually end up differentiating. We'll talk about this more, because you have the exact same question in Step Two, where the assumed offer is a thousand dollars.

Based on the constraints on the system and the losses on the system, you actually will get a dispatch that does reflect the value of the energy being delivered to where the load actually is, which will be different for every unit, even if it has an identical offer.

Mathematically, you could have a case where you have two generators at the exact same substation, with the exact same price, in which case, they would have the same value, merit value, but, otherwise, for --

MR. MERONEY: But it's differentiated, not based on the original -- the sort of production cost.

MR. DOYING: Correct.

MR. MERONEY: It's differentiated --

MR. DOYING: Based on the --

MR. MERONEY: By the other --

MR. DOYING: Yeah, correct.

MR. MERONEY: Okay.

MR. DOYING: Next slide.

(Slide.)

MR. DOYING: The peaker proxy offer, this is just a very simplistic example of how that would be worked up. And it represents the total hourly, as-offered production cost, so, importantly, it's not the incremental energy offer of the peaker; it's the all-in dispatch cost of those peakers, so, it includes incremental energy, no-load cost, and startup costs, and that's used to develop that hourly dispatch rate for the peaker, an that's what we use to develop the peaker proxy offer.

So just to show you a very simplistic example, if we have a single unit startup cost of $3,000 for start, no-load of $750 per hour, incremental energy at $100 a megawatt hour, and it's 50 megawatts, based on the formula, you can see at the bottom, you derive a peaker proxy offer for that unit of $175 a megawatt hour.

So that's the all-in dispatch cost of that unit for a single hour, and that's the calculation that would be done for all of the units, and then averaged to develop the marketwise peaker proxy price.

And, again, the formulas that we provided to you, go into greater gory detail on how that works. One of the cases, for example -- I noted that this example is very simplistic -- you actually, for each unit, would -- don't have a single point estimate for the startup cost, for example.

It's a startup cost averaged over the dispatch range of the plant, so it's actually a more complicated calculation for all of the units than looking at single numbers. You're calculating averages over dispatch ranges, and the formulas actually lay out the map behind that.

(Slide.)

MR. DOYING: Once we derive that total dispatch cost for the unit, we then divide it through by a spot gas price, and that's in order to take that and turn it into a heat rate, and that's the heat rate, then, that's used to develop the new peaker proxy price.

So, again, the first step is that we develop an average dispatch price for a unit, dollar per megawatt hour;

we divide it through by the fuel cost, and that gives us a heat rate, which we can then apply different gas prices to, to develop the daily peaker proxy price, and the next slide will -- the next few slides will show you what that looks like.

(Slide.)

MR. DOYING: Before we get to the actual examples, so we've walked through developing the price for a single unit. We do that for every hour of every day, so, each day, we calculate the single-hour offer cost of all the peaking capacity on the system.

We calculate a megawatt-weighted average value then, for each hour, and then on a monthly basis, we average all of those up to develop then for the month, a single heat rate that's used for that day.

So it's a whole bunch of calculations, but the intent is just to get an average value for those peaker offers. We want to be sure that we don't have -- we're not unduly influenced by any single day's offer.

We take a big slice of the system and we calculate it, hourly, over 30 days, and you've got a pretty good distribution, you've got a pretty good average that will come out of that.

(Slide.)

MR. DOYING: The next slides just walk you through what this looks like, based on some actual calculations, actual numbers. The first one is showing you, for that hypothetical plant we took at $175 a megawatt hour, just compares that to the actual distribution of peaker offers that we had for the day that we took the sample to do the calculation here.

You can see that the calculated price of $175 a megawatt hour, was more or less in the middle of the range of all the peaker offers, so if this was the peaker proxy offer for that hour, the higher of pricing would mean anybody who had a price lower than that, they would be out, they would get substituted with the proxy offer.

Anyone that had a higher price than that in their offer, they would go ahead and be dispatched, based on that higher cost.

(Slide.)

MR. DOYING: Again, we take that number and we apply it to a daily gas price. We'll talk in more detail about that when we get to the questions that you had sent us.

This is just showing you, for an historical period, looking at the Summer of 2005, June through August of 2005, gas price behavior, so we want to make sure that the proxy prices are an average heat rate for the system, but we want to adjust them every day, so they reflect then-current daily gas conditions, because that's what will actually determine the offers on any particular day, will be that day's actual gas price.

And you can see that, over that period, they range quite a bit; they range from a low of just above $6, to a high of a little bit above $12, so it's a fairly significant range. It's important to be sure that we capture that in the prices.

(Slide.)

MR. DOYING: The next slide then just shows you what those prices would actually work out to. The heat rate that we're using there, 23.5, that's based on the calculations we did earlier, so that was the peaker proxy heat rate, and this is just showing you that for each day, if we take that and calculate the proxy peaker offer price, using that heat rate and the gas price, you can see how that varies as the gas price varies.

Now, one simplification of this table that is not consistent with the actual implementation, is that we will actually calculate that peaker heat rate, every single day, based on the prior 30 days.

This is showing a single number for a week period. In reality, that number would vary a little bit every single day.

(Slide.)

MR. DOYING: Based on the gas prices that we saw, and, assuming that that heat rate doesn't vary, that it stays at 23.5, this slide just gives you then what the daily peaker proxy offer price would be for each day during that period.

Not surprisingly, since we use a constant for the heat rate, the shape of the curve here, looks a lot like the gas prices that you saw, but you can see that you do get a distribution, then, based on the gas price range from about $6 to about $12, and you get a daily proxy peaker offer from about $150 to approaching $300 on the most expensive day in terms of gas prices.

(Slide.)

MR. DOYING: In Step Two, it's much simpler. Again, consistent with the current tariff, when we release the remaining range above Economic Maximum, excluding regulation, we've now gotten all of the reserves in the market for dispatch, and the price is assumed, in that case, to be a thousand dollars a megawatt hour, and, again, that's the way the current tariff works for that process, as well.

So, the change that we're proposing here, is not to Step Two, which is what the tariff currently includes, but it's adding a new Step One, to give us a little bit more flexibility.

Again, as in the first case, the units are dispatched in merit order, and, as we discussed earlier, is based on the thousand-dollar assumed offer.

(Slide.)

MR. DOYING: Some of the questions were aimed at trying to identify the potential RSG impacts and how demand response plays in as well. We expect a secondary benefit to RSG. It's not the primary motivation for proposing the change.

The primary motivation is to aid reliability by giving us access, in defined circumstances, for short periods of time, to some of those reserves, and making sure that prices are appropriate during those periods.

But there will be a benefit to RSG, and the benefit comes from a couple of different places: One, prices that better reflect supply conditions on the system, will mean that we have fewer units eligible for make-whole payments, and lower make-whole payments to those units.

So, having prices reflect actual market conditions, is generally good, and has a benefit in RSG, to the extent that it lowers make-whole payment requirements.

It also may -- and this is a "may" we won't know until we have some operational experience -- it may reduce the amount of extra capacity we have to have online, in order to respond to load as it varies throughout the day.

You can't commit and have exactly the amount of capacity online that you need for dispatch in every five-minute interval; you're always going to have some extra capacity required, because you just can't commit units fast enough.

That head room, so called, to the extent we can reduce the uncertainty around our ability to meet load as it changes, we can reduce the amount of capacity committed, and, again, the units eligible to receive RSG.

So, there are benefits to RSG, but, in both cases, they are secondary benefits.

(Slide.)

MR. DOYING: Another question asked how this would interact with the demand response system in the market currently. The demand response that is available, is, in almost all cases, controlled by the balancing authorities, not under the direct operational control of the Midwest ISO.

So this will not have a direct effect on the deployment of that demand response capability. Again, it will have a secondary effect, in that, to the extent prices accurately reflect what's going on in the system, there will be a clear incentive for people to go ahead and take advantage of the demand reduction that they have available on their system.

To the extent you don't have demand response, it's typically because the economics don't make sense for the demand response, and getting the prices to reflect what's really going on, is helpful in that regard.

And it will likely provide incentives for additional demand-side development within the marketplace.

(Slide.)

MR. DOYING: The last question addressed market power mitigation, and that's the purpose of the second presentation, but you asked that we hold that for the afternoon, so, I won't go into that.

MS. HYDE: We'll see as we go along. It could be that questions come up on that quicker than we think, but at the moment, that sounded like a good plan.

I think that in terms of questions and discussion, this will be interesting. It could be that we'll finish earlier than we thought, you know. A lot of this is heading right for the questions we were going for, so, anyway, I think, given that we've made it through the whole discussion, it would be probably most beneficial to go through it section-by-section, as we kind of already set it out in our minds.

So, as we talk through some of this, I think we'll start out -- I want to ask one question first, just a clarifying question.

In several places in your filing, you said you be willing to make changes, et cetera. Am I correct in assuming that there's no additional filing coming in, that that's just a willingness, should the Commission choose to order you to make some of the changes that we saw in the answer?

MR. DOYING: I believe that we have one clarifying change that we need to make, based on the questions you identified, Commission Staff identified, to an erroneous citation to the Gas Price Index that we had used.

MS. HYDE: Okay.

MR. DOYING: And we will have to make a revised filing to identify the appropriate source for that gas price.

MS. HYDE: Okay.

MR. DOYING: Other than that, I don't believe we had any planned additional changes.

MS. HYDE: Okay.

MR. KESSLER: I just want to clarify that there were a number of other issues that were raised in some of the interventions that we addressed in our answer, where we had indicated that we would be certainly willing to add clarifications to the tariff to reflect those -- I think, the Gas Price Index or something that came up subsequent to that.

But we still stand ready to incorporate the changes that we identified in the answer, into the tariff proceedings. We have not yet prepared an additional filing.

MS. HYDE: Okay.

MR. KESSLER: Pending the outcome of this conference and the Commission's Order.

MS. HYDE: Okay.

MR. KESSLER: We, I guess, assumed that that would be in the context of a compliance filing.

MS. HYDE: That's fine. Okay, and now I wanted to turn it over to Lloyd Hull, who will ask our first set of questions. I suspect we'll be pulling up some of your slides again. They're definitely helpful on these items.

MR. HULL: Good morning, everyone. Other than the items that you mentioned in your presentation, what were some of the concerns that led you to propose this revision?

MR. GARDNER: Some of the concerns?

MR. HULL: Yeah.

MR. GARDNER: Basically, as we started market operations in April of 05, and we learned about some of the things that would happen simultaneous, to us. I covered a couple of them.

In terms of -- loss of large schedules, is the biggest thing that happens. And when those happen, we get very little warning, and we respond as quickly as we can, but we have a negative effect on frequency when those occur, until we can get the units online to replace the loss of the schedules.

MR. PATTON: You're talking about imports, right?

MR. GARDNER: Imports, right.

Now, a second thing that happens, is, we -- the first one was, generally speaking, caused by TLRs by other reliability coordinators like IESO Ontario, or, you know, Southwest Power Pool or TVA or somebody else.

The second thing that can occur, is, we -- market participants change schedules with 20 minutes. Basically, we get 20 minutes' notice of that, by the time they're all accepted by everybody.

And that can occur sometimes at the exact wrong time, like evening peak loads coming in, and the schedules go away, so we simultaneously, with very little notice at the same time load is rising quickly, lose schedules or imports.

MR. GARDNER: We have some significant pumping loads on the system and those can -- either the generators themselves can go off very quickly or the pumps can come on very quickly simultaneous with other things that happen that cause us to have the detrimental effect on frequency. Or the reserve sharing groups themselves they can lose units that don't require them to implement their own operating reserves. They just rely on the market to replace it. If several of those happen simultaneously or if that occurs simultaneous with some of the other issues I talked about, we can have a negative effect on frequency.

So that's caused us to, being good operators, we tried to make sure that we don't have a detrimental effect on reliability. We can't carry 3000 megawatts of head room just in case we lose 3000 megawatts of input. So we don't do that. But we do have a buffer, which is why we would have a positive RSG impact. That we do carry a buffer to try to take care of some of the things that happen. It's not large enough to take care of the larger things and so we just believe we -- and the tariff was silent on how we could actually use the reserves for this kind of purpose and we just felt it was better to make a filing, make it clear what we were going to use it for and have access and have the appropriate pricing when we did.

MR. MERONEY: Have or could you quantify how frequently some of these things occur because some of the things you've listed are -- granted that they may not be just sort of totality of your reason -- sound pretty specific. I mean have you made any attempt or could we just informally sort of guess how frequently this would happen?

MR. GARDNER: Sure. I'm going to say somewhere in the range of once a month to twice a month we'll have a fairly large change in resources or demand that would cause us to have to take some action.

MR. MERONEY: That last 15 minutes?

MR. GARDNER: Yeah, 30 minutes maybe most of the time.

MS. HYDE: Joe, about how big is the buffer have?

MR. GARDNER: It depends on the time of the day. You know, when loads ramping up, our buffer is a little larger because you have to have enough to ramp along with the load increase. Across the peak of the day when load's kind of flat, generally speaking, it's in the order of 700,000 megawatts. But it definitely changes as the time of day changes.

MR. HULL: Anybody else have anything they want to say?

(No response.)

MR. HULL: Okay, just a point of clarification, I know on your presentation you called Step 1 ARC.

MR. GARDNER: Yeah.

MR. HULL: And other times it appears "inclusive Steps 1 through 3." Is Step 1 ARC only?

MR. GARDNER: Yes. I apologize if we were not clear about that.

MS. HYDE: It was a problem that showed up in interventions as well. So if everybody could think of ARC as Step 1 and write on ARC as Step 1 and Steps 2 and 3 we were calling shortage condition, other shortage conditions. I don't know if there's a better label.

MR. DOYING: In the presentation I think we actually called that emergency procedures for intervention.

MS. HYDE: We'll have a question about that in a little bit.

MR. DOYING: But it is the sink. The current tariff provides for Step 2 currently and ARC is the revision that provides us some additional flexibility in that Step 1.

MR. HULL: Okay. It just wasn't clear in the original filing and we were getting confused, and I think the intervenors were getting it confused.

Joe here is going to be handing out -- these are copies of your exhibits.

(Handing out documents.)

MR. MERONEY: Joe, just to follow-up on this little bit, when you've had these events, what else do you do? Do you simply call in generation as quickly as you, bring it on and the frequency issues that you've seen hasn't been enough to take any further steps, so you haven't actually in these conditions made the use of the economic max.

MR. GARDNER: Essentially, what we're doing, frequency does go down and we continue to send out EDS solutions. Essentially, though, what we're doing is we're giving the EDS solutions that are deficient. We're sending out base points to the balancing authorities and NSIs to the balancing authorities that cannot be met with the normal dispatch range of the units. What ends up happenings on their side is their ace suffers and their ace goes negative and they end up using -- to the extent they can, they end up using their regulation to meet that difference. Depending on the severity of the issue, depends on whether the frequency suffers or not.

MR. MERONEY: So it basically goes back to the balancing and the manage of the resources.

MR. GARDNER: That's true. But generally speaking, they don't have enough in a lot of the events that we have to really balance and they do have control performance fixed on that period.

MR. MERONEY: Okay.

MR. HULL: Everyone has these I hope. On Exhibit

2B, as we were going through this, we thought it would be a good idea -- there's some calculations in these headings and I think it would be good just to go through and briefly explain the definition of each heading there in the highlighted and non-highlighted areas. This right here.

MR. GARDNER: Okay.

MR. HULL: Okay?

MR. KESSLER: Can I just ask you a question about these exhibits? Were these a single month that were just pulled out or a subset of data that was pulled out as complete set of data that was provided?

MR. HULL: This is just a single page of it.

MR. KESSLER: Thank you.

MR. GARDNER: Which one do you want me to do first? Do you care?

MR. HULL: Do the non-highlighted ones -- you know, the average emergency max of emergency units and then go across and explain the calculation there and maybe the corresponding highlighted. On one thing you have emergency maximum and then you have an average emergency maximum. And then, as you go on across the page, there's some calculations in there, and just quickly go through that.

MR. GARDNER: First of all, I'm going to go over Exhibit 2A first.

MR. HULL: 2B.

MR. GARDNER: I'd like to go over Exhibit 2B first. Do you want me to do 2B?

MR. HULL: Go ahead and do 2A.

MR. GARDNER: This is basically all the offered units, not just the committed units. So that's the distinguishing thing between 2A and 2B is 2A is all the offered units. 2B is the committed units.

The first column, Average Emergency Max of All Emergency Units, basically, any unit that was offered to us as emergency only. We added up all the offers of the high emergency limit and that's what's presented. The second column, Average Emergency Max of Non-Emergency Unit, is any unit that was offered not emergency. Then we added up the emergency max of all the offered.

The third column, Average Economic Max, is the units that were offered non-emergency, the sum of the economic maximums. The fourth column which it says "Average Emergency Max Minus Economic Max" should be Column 2 minus Column 3 or the average emergency max of the non-emergency units minus the average economic max of the non-emergency units of all the offered units.

The next column says for the units that were offered non-emergency this is the amount of spin self that they told they were going to carry on that unit. That's a part of the offer they can give us is how much spinning they're going to carry on that unit. That's just raw data, the average of that. The average rig up is the same thing in terms of all the offers. Wee averaged what regulation up-room they told us they were going to carry on all those units and the average reg down is amount of regulation down that the offers indicated they were going to carry on all those units.

VOICE: It's the reg up and the reg down. Is that for all emergency units.

MR. GARDNER: Not emergency. It should be non-emergency units there,

MS. HYDE: And when it says "average," it's the average across the hours, but the sum across the units?

MR. GARDNER: Yes.

MS. HYDE: Thank you.

MR. GARDNER: That is your operating reserve. Here's what we did. You gave a list of data you asked for that I believe, if I remember right, the list said "operating reserve." And so we said how are we going to do that and we thought it made sense to give you what we gave you because we don't have any other number. Okay. We don't have a specific number called "operating reserves" in the offers. So we tried to get as close as we could with the data we had.

MR. PATTON: But that number doesn't take out reg-up, does it?

MR. GARDNER: It does in the next one, but not in this one. In Exhibit 2A it does not take out reg-up I don't believe.

MR. PATTON: Okay.

MR. HULL: 2B.

MR. GARDNER: The difference now in 2B is these are only committed units. When we get to the column that talks about operating reserve, I think it's more indicative of what would be available for Step 1 or ARC on a typical basis.

MR. PATTON: Does it include gas turbines?

MR. GARDNER: No.

MR. PATTON: Okay.

MR. GARDNER: Offline. Online, yes. Offline, no. Okay. Basically, the first column is the same thing. It's the average of the emergency maximum of emergency units. And then of all the units that were committed and that were non-emergency, we added up the emergency maximums and that's the next column, average of emergency maximum non-emergency units. Then we add for the same committed units the average of the economic maximum and then we subtracted the two -- I'm sorry. I went too quick. Then we took the emergency max minus -- it says "dispatch max," but it really should say economic max since that third column says "economic max" and add it in the emergency. And so we gave you a number that basically indicated, okay, of the online units this is how much emergency max there was. This is how much it -- and the difference between emergency max and economic max on the online units is this much, and we added the AME to that and gave you a column because that was a close as we could come to what you were asking for in terms of operating reserve.

MR. MERONEY: So it should be AME would be the number in column 1?

MR. GARDNER: Yes, it should be.

MR. MERONEY: So that should equal column 3 minus column 2 plus column 1?

MR. GARDNER: Yes. I think it should. I haven't done the math, but it doesn't?

MR. MERONEY: I don't think so.

MR. GARDNER: It maybe the averaging effect that's causing it to be thrown off.

MR. MERONEY: That's the only thing I could think of.

MR. GARDNER: Yeah.

MR. MERONEY: I don't know.

MR. GARDNER: The next column is emergency max minus the dispatch max minus the regulation up. So basically, this is indicative of, on that chart, the pink area and the yellow area. And then the average of the reg=up is that red area and then the reg-down is the bottom red area. I think the key number out of all of this is the column that's labeled "Average Emergency Maximized Dispatch Maximum Reg-Up," which is the one, two, three, four, fifth column of numbers is the key column.

MR. HULL: That's the pink and yellow on your bar chart there?

MR. GARDNER: Right. So what we would have access to is half. In Step 1 or ARC we'd have access to half of that.

MR. HULL: Okay. All right.

MR. PATTON: Can I ask a clarifying question so we minimize any confusion? If the emergency units are online, is this largely -- the emergency units are mostly gas turbines. Right?

MR. GARDNER: Yes.

MR. PATTON: If they're online producing energy, then they're no longer reserves, are they?

MR. GARDNER: Right.

MR. PATTON: So maybe it's column 5, but taking out the emergency units that you show because they're already running?

MR. GARDNER: I may have to check on that, David. I don't know.

MR. PATTON: Okay.

MR. HULL: And I think David just mentioned, because I had a note here, the high emergency units are quick-start, offline resources. Right, more than likely?

MR. GARDNER: More than likely, but we don't have a offer mode called "operating reserves" and so when we started up the market -- we talked to David about it and we told the market participants that if you're -- so that we don't commit a unit that's offline that you're counting on operating reserves, put that unit in emergency only mode so our software won't automatically pick it up as if it's available for normal use since you're using it for operating reserves. So just to clarify what your question was.

MR. HULL: Okay. But it's not something that's going to take 14 hours to start-up then?

MR. GARDNER: No. Not generally speaking, no.

MR. HULL: Okay. Just to walk us through this again, you have one there that's highlighted that says "August 2005." The row is highlighted. It says "August 2005" on it.

MR. KESSLER: October 2005? October?

MS. HYDE: 8 2005.

MR. HULL: One of the 2Bs, yeah. Take us through this real quickly and explain how ARC would work.

MR. GARDNER: Okay, the only important number for

ARC purposes is the fifth column titled "Average Emergency Maximized Dispatch Minus Reg-Up" and that is hour 16th, the highlighted row, 3936 megawatts. What would happen -- and this is an average of all of the hour 16s, but assume this is one day for a second and we have 3936 megawatts and we needed to institute Step 1 or ARC. We would call on the procedure. We would arm the dispatch software by hitting a switch that basically said you now have access -- telling the dispatch software, in effect, you have access to half of the 3936 megawatts.

MR. HULL: Roughly, 2000 megawatts?

MR. GARDNER: Roughly, 2000 megawatts. Each unit, halfway up, on each unit, on a unit-by-unit basis, you can now raise that unit up that many megawatts. And we also want to hit the switch as substitute for the portion of the curve between the dispatch max and that 50 percent point, the peaker up, the peaker proxy price for the offer that they've made. And the dispatch software will automatically then just dispatch the units as if their maximums had always been that higher level with a new offer in them.

MR. HULL: Okay.

MR. MERONEY: Joe, will all those offers actually be available to the dispatch, not ramp constrained at that point?

MR. GARDNER: It will still honor the ramp limits.

MR. MERONEY: But you still have to honor the ramp.

MR. GARDNER: We'll still honor the ramps.

MR. MERONEY: Does that really limit the amount that you have?

MR. GARDNER: It limits it in each five-minute period, yes. But it gives access -- you have to remember that when we're in this mode every unit like -- not always, but likely -- you know, 400 units, maybe 350 units are at dispatch max and they've got reserves on them. And so they could all ramp some. So when we hit the switch, we do gain access to a lot of capacity.

MR. MERONEY: Does this relate a little bit to the kinds of conditions we were talking about before where, if it occurs kind of in the middle of the day, in the afternoon, things may be more likely to be at maximum by the ramp constraint and it seems to, by what you were saying before, be less of a ramping issue in the morning when a number of those units would be already kind of limited by ramp. They'd be going up anyway or something like that.

MR. GARDNER: These events can happen different times of the day. Sunday evenings tend to be the higher percentage, believe it or not, of the types of events that we have. And the main reason for that is that's the fastest, shortest load growth period. It's a very steep ramp increase and we sometimes run into an issue on Sunday evenings, especially if any of the other things that I talked about happen at the same time. But it can occur any time during the day.

MR. MERONEY: It sounds like you've made a perfectly reasonable -- you're banking on having a fair amount that are essentially sitting at the dispatch max so that this procedure will then release within the ramp constraints capacity that you right now don't have access?

MR. GARDNER: That's right.

MS. HYDE: I'm not sure if this got asked before, but you said they go in -- the software treats it as going in at the higher the peaker proxy or the offer. Now looking at it from an efficiency point of view, you'd want your cheaper ones, the ones that actually have lower costs that are under the peaker proxy rate going on first, I would think. So does the software take that into account? It doesn't?

MR. DOYING: From an efficiency perspective, I think what you're looking for is the lowest production cost.

MS. HYDE: Yes.

MR. DOYING: And that's production cost that is cleared in our market, and from that perspective the actual production cost of a unit meaning their short-term fuel and variable operation costs isn't really relevant. It's their offer to us. So we are minimizing production costs by dispatching them in merit order irrespective of what their actual fuel costs are, which we don't know for any unit anyway.

MS. HYDE: But you are dispatching them in terms of below the proxy. I know they're going to get paid the proxy and the proxy is there set the price, but the dispatch, when you peak that, is that offer or is it as if they're all equal?

MR. DOYING: As if they're at the peaker proxy price. If you tried to reflect the actual fuel cost, assuming that that's what they had offered for that segment, we could actually end up with dispatch that was inconsistent with the prices that we saw because the LMP prices that are established are going to be based on that proxy price. So if we're dispatching on a set of prices that is not consistent with the actual prices that we're solving for, we have the likelihood of having dispatch that's inconsistent with the pricing on the system.

MR. MERONEY: Yes, there's a conflict there between the requirement of consistent LMPs with the essential dispatch frequently working them. Doesn't that mean that you -- had you been dispatching on the offered cost you would unquestionably dispatch a $20 call plan before a $65 one if the proxy is like 175 now they're treated equally.

MR. DOYING: An important thing to remember is we're trying to price the value of the reserves that we're releasing, not the variable production cost and both of those units have an equal contribution to the reliability of the system when they're carrying reserves and that's the value we're trying to capture with the dispatch and with the production cost minimization that's inherent in the UVS solution. So fuel cost is not relevant to the economic efficiency of the outcome. It's the value of the segments released and that's sort of the notion behind using the peaker proxy or the thousand dollar level is that what we're trying to capture is the value of the reliability associated with those reserve segments that are being released for energy production purposes.

MR. MERONEY: Essentially, you're stepping in and having some proxy represent what the reliability opportunity cost is?

MR. DOYING: The reliability opportunity cost.

MR. PATTON: What you don't want to do is have the reserve segments displace non-reserve segments that were previously being dispatched because it's more costly to dispatch the reserves even if their offer price is technically lower than a non-reserve segment. Where I think you guys are having some question is what if you're looking at two reserve segments and they have different offer costs, then if I'm choosing between dispatching this reserve segment or that reserve segment it make sense to try to dispatch the cheaper one, but that's probably secondary to ensuring that you structure it in a way that resist dispatching the reserve even once you've released it and still try to fully utilize the non-reserves.

MR. MERONEY: One more thing on these exhibits here. Exhibit 2A, for the month of April 2005, 0 through 23 and several other instances the economic maximums are higher than the emergency maximums. Can you explain that? If you go through the map there, it doesn't add up. Is this an average thing?

MR. GARDNER: I don't know. The only thing I could do is ask the people that did the query and get back to you I think.

MR. MERONEY: That's all we were trying to ask at this point. That didn't seem like it could be average.

MR. GARDNER: Right.

MR. MERONEY: Just in terms of your looking, after just looking at things, I would also go back and check where we were before on the commitment units because my fairly quick said that the spinning reserve number tallies exactly with the summation across the rows and subtraction and so on, whereas the operating one didn't and so that seemed a little strange, worth a second look.

MR. GARDNER: Okay.

MR. HULL: Any other questions, comments on these exhibits?

MR. GARDNER: If we find an issue, we just resubmit a new -- do you want us to just e-mail it to you?

MR. GREENFIELD: There probably should be a more formal submission so that the record has something on it.

MR. KESSLER: We'll give a supplement data response.

MR. HULL: Okay, Jay, you're probably the one to do this. Can you go through MISO's current requirements or practices for determining their reserves, the operating, the spinning, supplemental regulation up and down?

MR. PATTON: It's actually very easy. We don't.

(Laughter.)

MR. PATTON: Currently, until we have the ancillary services markets in place the balancing authorities are required to carry their operating reserves in responsible to ensure that they have their operating reserves. The way they do that is by submitting to us economic maximum limits that when we honor them give them the room above that to carry their reserves. So if they only at one unit and they had a 100-megawatt operating reserve obligation and they choose to carry that all online, they would make sure that the economic maximum that was submitted to us was 100 megawatts lower than the top end of where they would say the reserves were being carried and we would honor that and they would then have adequate reserves.

MR. HULL: Okay. Each balancing authority within their control area.

MR. PATTON: Some balancing authorities carry their reserves in their head room below economic maximum, and if that gets eaten up, presumably, they start units to try to restore it.

MR. GARDNER: What David's saying is, let's say it was 100 megawatts in my example, they may only put 50 megawatts here and count on the fact that we would be within 50 megawatts of economic max. If we do, they would have to bring another unit on to make that back up. But it's their responsibility to do that. We don't take action to do that for them.

MR. MERONEY: Do they tell you ahead of time what units they would start up or do they tell you when the do that? Do you get notified anywhere in that process?

MR. GARDNER: Generally, we get told that a unit's coming online, yes.

MR. MERONEY: Is there an obligation for them to tell you that?

MR. GARDNER: There's an obligation to tell us when a unit is coming online, yes.

MR. MERONEY: In your example, you had them basically carry a hundred, but they just carried 50 there and you basically said, assuming you're not going to get close and if you get close then they'll start something else up. They don't need to tell you -- I guess I'm a little unclear. What do you know ahead of time about where the reserves are actually being carried with respect to what units in a balancing area.

MR. GARDNER: They have in their offer curve a value that they say they're carrying their spin from. That's not always updated, though, by every market participant. So we really don't rely on that. We look at it in total. Each balancing authority sends us their operating reserve requirement and sends up, in real time, the amount of operating reserves they're carrying and the reliability coordinators are responsible for monitoring those two things -- make sure that their operating reserves are greater than their operating reserve for quantity. That's separate, though, from the dispatch algorithm. So we're monitoring that as the reliability coordinator, but the dispatch algorithm itself is not doing anything with that information.

MR. MERONEY: I think you did. Essentially, if you're just looking at the dispatch and the offerer and the EDS and so on, you don't necessarily see everything that you'd see on the RC side.

MR. GARDNER: Right. The dispatch algorithm will dispatch the unit up to maximum regardless of what else is going on, regardless of whether -- if they've gone to a maximum that was too high such that if we dispatched from that high they would be short of their reserves, the dispatch algorithm would do that. It would dispatch them up. And we're relying on them to manage those limits.

MR. DOYING: Importantly, Joe mentioned briefly is the ancillary services markets are implemented then, in fact, that all will be represented explicitly as part of the offer. There will be new offer parameters whereby they will tell us exactly where they have the ability to try to reserve and we'll instruct where the reserve should carried, to the extent they're not self-scheduled. But it will be much more explicit in terms of the information that we have.

MS. HYDE: When do you anticipate the ancillary services market?

MR. GARDNER: Well, you know, the current schedule was a filing to you December 1st I think or so with the implementation.

MR. KESSLER: Right now the implementation is anticipated between end of third quarter of 2007 to first quarter 2008, depending on the outcome of the proof of concept studies that are underway.

MS. HYDE: Okay, thank you.

MR. MERONEY: Just to follow up the point that you made before, Joe, the spinning reserves numbers that we have are numbers that basically come out of the dispatch system. Right?

MR. GARDNER: The spinning reserve numbers?

MR. MERONEY: That are on the committed units, for example. When you explained the hour 16 number, you pointed to that number as the key number and that's what you would see in the dispatch in terms of economic maximum, emergency maximum and the emergency units. Right?

MR. GARDNER: That's right.

MR. MERONEY: So that came out of the dispatch system so that in your example where you had 50 megawatts, you would see 50 megawatts here?

MR. GARDNER: That's right.

MR. MERONEY: Okay.

MR. HULL: Several times in the filings and in the tariffs there is a high emergency range, a high emergency dispatch range. Are they interchangeable or define the term?

MR. GARDNER: They should be interchangeable. I don't know why there would be a differentiation between those two terms. Sometimes we use high economic limit. Sometimes we use dispatch limit, too. So we interchange those two terms as well, but the two terms you said were high emergency limit and high emergency dispatch limit?

MR. HULL: High emergency range, high emergency dispatch range and they were stated --

MR. GARDNER: If you could point me to the tariff I could perhaps --

MS. HYDE: I know that the old tariff language Step 1 had at least one of those terms in it.

(Pause.)

MR. DOYING: While Joe is looking for that language, I will say there are places like that we've discovered. When we filed the original tariff, we had terminology we are using in how it says "vendor started delivering the system" using slightly different words for things that are actual offer templates. You end up with different words meaning the same thing.

MR. GARDNER: Let me just be clear. I'm talking about Section 40.2.15 original Step 1.

MS. HYDE: That's on Sheet 267.01. That's where I just found it -- at least one place.

MR. GARDNER: I think that's right.

MS. HYDE: Towards the bottom?

MR. GARDNER: And the words say "the transmission provider will either (i) employ the emergency range that determine," is that the one we're talking about?

MS. HYDE: Yes.

MR. GARDNER: Okay, when we talk about high emergency range in that case, it's a little bit different and what it would be is it's the amount -- the yellow and the pink excluding the amount of reserves they told us they're carrying on that unit because in this Step 1 you use the offer -- and this is the old procedure -- you'd use their offer first that they'd submitted for that portion. And then in Step 2, you go into their operating reserves and you substitute a thousand dollars. Okay. I don't have a picture of it. What you have to do is imagine it. That's why it says "includes contingency reserves." It's the same example where we had 50 megawatts between the economic max and emergency max and they said they were carrying 25 megawatts of operating reserves on that unit and no regulation make it easier. Then the high emergency range under that provision would have been 25 megawatts. That's correct.

MR. HULL: And the high emergency dispatch range is from eco max to high emergency max?

MR. DOYING: Do you have the tariff citation for that one as well so we can get the context?

MS. HYDE: I don't think so.

MR. HULL: No, I don't think so.

MR. DOYING: If you can locate it, we can certainly add that to the data supplemental.

MS. HYDE: Those sorts of things are what tripped us off an awful lot because I think had terms that we hadn't -- and they weren't always defined in the tariff either, and some of them were disappearing, but we still wanted to know how things were changing.

MR. DOYING: Hopefully, with the new filing the terminology was all very consistent and used words like econ max, emergency max.

MR. HULL: The operating reserves that the yellow and pink area on that bar, isn't it? Is that what you call an operating reserve?

MR. GARDNER: It includes the operating reserve. It could be more than that.

MR. HULL: Could you define that, what all is included in that range?

MR. GARDNER: I can't say anything other than the market participant has given us an economic maximum lower than their emergency maximum and generally speaking, they carry a portion of their operating reserves in that range. But that number can be bigger -- the difference between those two can be bigger than their operating reserves.

MR. MERONEY: It could be smaller, too.

MR. GARDNER: It could be smaller too, yes.

MR. MERONEY: Okay.

MR. HULL: On page 8 of the July 11th answer, did you state you would be willing to amend the proposal to specify that portion of the operating reserves would be returned to the market participant upon the occurrence of a reserve sharing or DCS event. Are you planning on making that modification?

MR. GARDNER: Yes.

MR. HULL: Okay.

MR. GARDNER: That was one of the ones we're committed to.

MR. HULL: What's the process for returning those megawatts?

MR. GARDNER: What we would do is the dispatch software, if that participant had an event that they needed it, we would turn off the ARC switch for that area.

MR. HULL: For that balancing authority.

MR. GARDNER: For that balancing authority.

MR. HULL: How is that going to affect your process for carrying out shortage procedures?

MR. GARDNER: It would shift. The amount that we had been requesting from them to the other balancing authority units is what the result would be.

MR. HULL: Spread the pain?

MR. GARDNER: Yes, because the dispatch for that balancing authority would see the high limits, which had been up here, drop back and it would have to use the range in the other areas.

MR. HULL: Anything else?

(No response.)

MR. HULL: This is a general question. Will the Midwest ISO be able to maintain the required amount of reserves when ARC is invoked in these site standards. I think you pretty much did that with the presentation, but you'll be able to carry the required reserves to meet the standards?

MR. GARDNER: Right. Well, we'll be using the reserves for this short period of time similar to what they were used for historically and similar to how they're even used today when units are lost. We'll be deploying them and like I indicated we'll be replenishing them within the timeframe that the reliability standards require.

MR. HULL: Thank you.

MS. HYDE: Does anyone else have any questions on the mechanics of the process that we've been talking about so far this morning?

MR. HEGEDUS: I guess I'm a little confused about the relationship between contingency reserves as we have them today and the additional reserves that you're getting here. The contingency reserves I presume are already available to you to help you out when you need ramp or why are you shaking your head no?

MR. GARDNER: They are not available to us under the current tariff other than through the existing 40.2.15, which we try to modify for this purpose to give us access during these types of events.

MR. HEGEDUS: Are those existing contingency reserves already -- those are already being paid for, I presume, under the OITT?

MR. GARDNER: I don't know if we want to get into this or not. You guys can tell me, but basically -- okay, if I go into things you don't want me to, let me know. But the existing balancing authorities all have their own ancillary services tariff schedules. They're still on file with the Commission for Schedules 5 and 6, and the Midwest ISO tariff points to those schedules but each balancing authority has their own tariff schedules for operating reserves.

MR. HEGEDUS: Those operating reserves are paid for via those ancillary services schedules?

MR. GARDNER: Capacity.

MR. HEGEDUS: Right.

MR. GARDNER: Yes, customers would pay under those schedules. Right.

MR. HEGEDUS: Would this be an additional payment if they were called upon under 40.2.15?

MR. GARDNER: What would happen in this case when we implemented it is we would implement the dispatch software with high limits. We would set the LMPs appropriately after we substituted for the peak proxy if it was higher than the original offer and the generators would get paid through the market for the fact that they generated that much more at the LMP third level. That's what would happen. Does that make sense?

MR. HEGEDUS: I'm not sure. Would the contingency reserves come in now? Is that what that says?

MR. GARDNER: Step 2 -- what I was trying to show there was that Step 2 we had access to both the pink and the yellow. And in Step 1, we only had access to the pink.

MR. MERONEY: If you were to use contingency reserves under the current tariff, what would you have to do? Would have to invoke Step 1 under 40.2.15? Is that what you have to do?

MR. GARDNER: We could invoke Step 1. No, to get to contingency reserves, we'd have to invoke Step 2 under the existing 40.2.15.

MR. MERONEY: Step 1 would just get you to the portion of the pink -- Step 1 under the current tariff would just get you to the portion of the pink and yellow that wasn't carried as operating reserves?

MR. GARDNER: That's right.

MR. MURRAY: In the presentation, a couple of additional things came out. There was an identification that sequentially, before the ARC procedure is tripped, there will be three cycles of the UDS, so that's kind of turning event. And then, Joe, you actually mentioned you'd be able to dispatch up into range in the chart. There's going to be a switching software that gets turned on. So let's assume that's happened. We're in Step 1. As I understand it, as the tariff reads, there's a 60-minute window that's now active that, unless something happens in that 60-minute window, we now trigger Step 2. What does MISO plan to do during that 60 minutes? Will MISO actually step in and commit additional resource at that time. Or is MISO looking to have the scarcity pricing that's going to be active triggering market response?

MR. GARDNER: We're currently planning to - we're committing units to get back out of Step 1 within 60 minutes. I was careful how I said that. Let's say we see an NSI change coming 20 minutes out, 30 minutes out and we know it's going to happen it will eliminate the need. We wouldn't commit units in that case. But we would commit units to get out of Step 1 as quick as we could -- whatever we had to do to get out.

MR. MURRAY: If that happens, is MISO committing those units to supply energy into the market or to supply reserves? I mean if you supply energy into the market, presumably, the reserves get restored back to the VAs.

MR. GARDNER: Essentially, it's energy. When we commit them, they become available for energy. Once we have enough online, we can eliminate the use of the reserves and we would turn off the switch that we had turned on and start dispatching the original units back down to their economic maximum scale.

MR. MURRAY: I would presume, because of the timing sequence we're talking about, the committed units in this context would have to be quick start.

MR. GARDNER: Yes.

MR. MURRAY: When MISO commits them in this scenario, are those units eligible for make-whole payments?

MR. GARDNER: Yes, it would be considered reliability assessment commitment units. They would be eligible for make-whole payments.

MR. MURRAY: Would you expect them to incur make-whole payments in this scenario?

MR. GARDNER: Yes, I think they would. It's important to note though, Kevin, we're already doing that. That's not a change. We have these issues today. We commit these units. The change that we're proposing here is a reliable solution in the interim between the time we have the event and the time those units we've committed come online. Right now we are having a negative impact on frequency and causing our balancing authorities to incur performance hits.

MR. PATTON: There's also an economic issue to the extent there really is temporary committing a peaker that's going to stay on for an hour, has to stay on for an hour is really an inefficient thing to do so that it's possible we use the reserves. The situation last 15 minutes and you never do bring on the peaker, which is a good thing for everybody because, like you said, the peaker in all likelihood would be more costly and results in higher RSG payments. In addition to that, I think your question was does this involve procuring more reserves? I think of it as actually procuring less reserves. You certainly aren't changing anything about the quantity of contingency reserves. But like Joe said, if they now have head room, cushion or -- I can't remember what he called it -- to respond to these sorts of events, you can think of those as being sort of a class of reserves that are available to MISO. And if they can run closer to zero with this procedure, then they're actually, in a sense, procuring fewer reserves and there's a cost of maintaining 700 to a thousand megawatts head room in terms of commitment cost and

RSG. So it seems fairly unambiguous that this would lower costs, although there's caveats around that.

MS. HYDE: Mike?

MR. BOUGHNER: I have a couple of questions. I want to go back to the releasing of reserves if there's a contingency reserves sharing event. I just wanted to see if you guys could expand a little bit about how you see that working in terms of the ability of the reserve sharing group where the contingency occurs to be able to make a DCS event if the reserves that you essentially called on during the ARC procedure have already been deployed, if all the units are already ramped up and now there's an event and you need more ramp to fill in that void somebody is going to wind up short, either the market or the reserve sharing group. I just want to see if you can fill in some gaps on how you perceive the ability of the reserve sharing groups to maintain a CCS compliance. And as far as spreading the pain issue goes, transferring the responsibility for the remaining part for the ARC portion of reserves that was deployed by the entity that now it has to be returned to, given that now on January 1 the whole Midwest region, the whole market, including non-market participants, are going to be in one reserve sharing group. Who do you spread that pain to?

MR. GARDNER: Who do we what?

MR. BOUGHNER: Who do you actually now spread the requirements to pick up the reserves that were deployed by the entity that now lost a unit and is calling for reserves. Who do you spread their portion of the ARC deployment to, given that everybody now is going to be in one reserve sharing group and they're all going to be potentially calling on their reserves to respond to it?

MR. GARDNER: Right. Mike, in response to your first question, what I would suggest that you do and the balancing authorities do, when we have an event that requires use of your reserves, we're going to let you know. You would tell your reserve sharing pool at that point I'm using my reserves of this many megawatts. So that if an event happens in the reserve sharing group, the reserve sharing group knows you're not carrying that point and gives less of an assignment to you and allocates more to others.

As far as the second question, in January who does it shift to, it would end up going to different units because we'd be sending base points out. I'd have to work out an example, I think, but it would end up going to different units than the original than if we had not been using the reserves and you lost your unit and the reserve sharing group allocated it, it would come under that set of rules, which would then be modified somewhat for what would happen when the contingency reserve share group goes --

MR. BOUGHNER: I guess by different units, if you're in Step 1 I guess that could bump you into Step 2 because presumably in this scenario you're sort of out of units to ask for a response from, so you need units that are in this operating reserve range. So it could take you from Step 1 to Step 2.

MR. GARDNER: Potentially, it could.

MR. BOUGHNER: And if you're already in Step 2, I guess who knows what happens? I guess it goes to Step 3 next.

MR. GARDNER: Right. But I really think the right answer is when we use the reserves for this purpose to tell the reserve sharing group the amount of reserves you're carrying for this period of time is reduced because you're using them for a different purpose and I think that will take care of the issue of what happens when the next event happens.

MR. BOUGHNER: Yes, if you could work up an example, I think that would help. I don't know through what process to do that. Just a couple other quick questions. The substituted offer, if you want to hold off until the afternoon, that's fine.

MS. HYDE: The pricing list do hold off until the afternoon. Yes.

MR. BOUGHNER: I guess the last one I have for now is, in terms of the applicability of Step 1, 2, 3 and when those will be used, some of the comments XCEL submitted they were along the lines of more clarity in the tariff as to what kind of events will actually cause --

MS. HYDE: We're going to do that after our break.

MR. BOUGHNER: No problem.

(Laughter.)

MS. HYDE: We think we're on top of that. We'll see.

MR. BOUGHNER: All right.

MR. MERONEY: Be prepared, though, because we're not.

MS. HYDE: Does anyone else have anything?

MR. FARRINGER: Jerry Farringer from Consumers Energy. Joe, we talked about earlier the operating reserves and before the ARC tariff and what you do now basically and that is to -- and correct me if I'm wrong -- make sure I'm understanding it correctly. You essentially, in the UDS case that the balancing authorities can supply, hoping that they will utilize their reserves appropriately to come back into balance. With that being the case, the balancing authority really isn't aware of that situation. Is that not true? I mean it's a run of the case and the balancing authority really doesn't have or the market participants that are supplying the reserve really don't have an indication that you really want more than just the regulation now. You're actually trying to get into the contingency reserves.

MR. GARDNER: In this scenario?

MR. FARRINGER: Prior to the ARC procedure, that's Day One. That's what's happening. Is that not true?

MR. GARDNER: No, right now when we start -- the current procedure says that if we are short by -- I think it's a thousand megawatts for two consecutive UDS cases, we send the message out telling you what the situation is and why.

MR. FARRINGER: And that's relatively new.

MR. GARDNER: Three or four months. Something like that.

MR. FARRINGER: At least with the ARC procedure -- I guess the point I'm trying to get through with the question I have for you is, at least with the ARC procedures, entities would be well aware of the situation that was taking place. The problem that I see is that you're expecting to be able to get into this operating reserve area and units may be blocked. They may not be able to get there without over-fire fuels. If the market participant doesn't know they have to do that to get that extra energy, then they're not going to. So essentially, the system is not in balance.

The second question I have -- actually, the first question I have. The first was a statement.

(Laughter.)

MR. FARRINGER: One of the benefits, and Richard, you called it a secondary benefit, but one of the large benefits in my mind was the possibility to reduce that hold-back, which has been defined between 1.5 and 2 percent at times. I heard in your presentation that that may not be the case. I guess I'm curious if you could expand on that.

MR. DOYING: I'll expand only very briefly and then turn it over to Joe, who actually has to manage that on a day-to-day basis. But the point I was trying to make was it's very difficult to quantify that because it is based on all of the factors on the system and only experience will tell us as we implement the ARC procedure how much better ability we have to manage that head room on a day-to-day basis. So not suggesting that there's no benefit there. We're just saying almost impossible at this point to try and quantify what that benefit might look like.

MR. GARDNER: I'd like to see a few events occur, see the response that we get when we implement the procedure, how well it works and then go forward with adjusting appropriately.

I thought we had a statement in our presentation that indicated that when we implement this procedure we will send a message out to market participants and balancing authorities, but I don't see it. We do plan to do that. The draft procedure that we've written says that.

MR. FARRINGER: Okay.

MS. HYDE: That was the question that we had for the next session because we didn't see any notifications going out.

MR. GARDNER: I thought we had that in there, but I can't find it.

MS. HYDE: It's time for break. If we could break and be back here at 11:00 and then we'll move into the next session, one more session of questions. Hopefully, we'll get through it all before lunch.

(Recess.)

MS. HYDE: I don't know how long this section will take. We'll just find out. I suspect it will be a good time to break when we're done with this section.

In the filing, Section 40.2.15 refers to the procedures in this section being implemented when ISO forecast of demand cannot be satisfied with all available offers, including demand response offers. Now you mentioned demand response a little bit this morning in the presentation, but are there any obstacles you know of in the way of demand participating in the market such that, if those obstacles weren't there, the ARC procedures wouldn't need to be used as much?

MR. GARDNER: No.

MS. HYDE: Any elaboration there?

(Laughter.)

MR. GARDNER: First of all, the demand respond that that's referring to are the formal DRRs that can be registered. There are, I believe, on 10 megawatts worth -- somewhere in that neighborhood registered. It's not very much registered right now. And demand response, in general, I don't know what to say about that. Richard may have a better answer.

MR. DOYING: Only to reiterate again it's not deployed by the Midwest ISOs. To the extent that we have better mechanisms for participation by demand in the market and that's certainly something that we're very interested in, our stakeholders are very interested in. They're getting ready to start up the demand response taskforce. That will certainly provide additional flexibility, which would give us other alternatives and maybe avoid instances that we would have to otherwise go into ARC.

MS. HYDE: There's definite Commission interest in this.

MR. GARDNER: Sure..

MR. BOURBONNAIS: I can add a touch to this. Most demand response today is not short-term, quick response. Most of it has an hour, two or three. So the current demand response wasn't designed for this. Once the committee gets going, maybe they can come up with some ideas. But the current stuff is not --

MS. HYDE: The current example is not very responsive.

MR. BOURBONNAIS: Yes, not to this type of order. It's too quick.

MS. HYDE: And that's true even once you're within the ARC shortage procedures it's still not much it's going to be able to come on right now, demand response?

MR. GARDNER: No.

MS. HYDE: Okay.

MR. MERONEY: When would you currently call for demand response under the tariff or under what conditions I mean in the sense that if this does go on for an hour there's still -- you know, there's other things that have to happen. Would a call for demand response be going on during this time?

MR. GARDNER: I can tell you what we did the week of July 31st. We called for demand response prior to calling for the maximum generation event. When we say "call for demand response," what we did was we asked or directed the utilities to implement their load production programs there and go out for public appeals of voltage reductions, start behind-the-meter generation. That's what we did that week prior to calling the event and the reason was because we noticed this was going to be needed to get those implemented.

MR. MERONEY: Prior to calling the max gen event?

MR. GARDNER: Right.

MR. MERONEY: You previously called the warning -- call for the warning would have preceded the call for the event?

MR. GARDNER: Yes.

MR. MERONEY: Was it at the time of the warning or sometime between the warning? I mean is there a stated specific procedure about when you make that call?

MR. GARDNER: Yes, there is a whole presentation that goes through the exact sequence of events that we did on all three days -- July 31st, August 1st and August 2nd that I could send to you.

MR. MERONEY: I think I may have that.

MR. GARDNER: Okay.

MS. HYDE: I might like to see it, though. I don't have it.

(Laughter.)

MR. MERONEY: Maybe it's something different from what I have. Actually, I think I have David's.

MR. GARDNER: We could send it to you.

MS. HYDE: This was something that came up before the break. It's prior to the proposed changes, so the existing 40.2.15. Market participants are notified that shortage conditions exist with the issuance of a maximum emergency warning. How are they going to be notified now that the ARC procedures are in place -- ARC or Steps 2 and 3 are in place? Do you have a procedure for that?

MR. GARDNER: We have a procedure. It's a draft procedure. We're going to put a message out on the MSS, which is the basic messaging system for the portal. So we'll send a procedure notification out on that. We will also send a notification out on the messaging system that's to the reliability entities, which is called OICL, but it's the reliability entities and then we'll send a separate message to the market.

MS. HYDE: The next question, the transmittal letter you sent in at page 3 said the ARC procedures initially -- that's going to be a key word in the questions -- should be implemented only under certain short-term contingencies when it may be necessary for the Midwest ISO to increase the amount of generation ramp the reliability of online generation in order to meet load and manage constraints until additional generation can be committed.

The first question is what is meant by "initially" in that sentence? Do you plan to implement it differently beyond any initial period? And if so, is that reflected in the tariff language?

MR. GARDNER: Could you point me to the sentence? Is it the first full paragraph there on page 3?

MS. HYDE: Yes, the first sentence of that first full paragraph.

MR. GARDNER: I don't know what we meant by "initially" there. Michael, do you?

MR. KESSLER: I think the draft tariff language is actually broader than those specific limiting circumstances and we were indicating in the transmittal letter some of the specific circumstances where we thought that it would be applied initially. But the tariff isn't actually so limited by those specific circumstances.

MS. HYDE: I guess when I read "initially," I was thinking for the next six months we're going to do it this way and then something changes. You're using "initially" in a different manner. You're saying the first thing that happens in this process, using "initially" that way?

MR. KESSLER: No. What I think we're saying is we would expect that the initial implementation of ARC would be in the circumstances that are described in the transmittal letter. There may be other circumstances that are permitted by the tariff language once we have experienced implementing the ARC procedures where it may also be applicable. But these were the specific circumstances that we foresaw using the procedure specified in the tariff filing.

MS. HYDE: Okay. I have another question on the same sentence, which is to what extent are the shortage procedures designed to address local congestion and shortages rather than system shortages and to address congestion in general because I read the tariff sheets to deal with shortages, but not necessarily congestion. And perhaps system-wide congestion surely, but anyway, I'm trying to sort through what's said here and what's in the tariff sheets and where you're going with this.

MR. GARDNER: First of all, the software itself has the capability of being implemented on a balancing area by balancing area basis no smaller than that. So we would never go below a balancing authority. I believe the main intent is to use it on a system-wide basis. There may be some cases it could become applicable for on a smaller than a whole footprint basis, but it would never be on a very local basis.

MS. HYDE: With respect to shortage conditions where you really can't get the generation you need or high prices with congestion, which or both are you planning on using this under?

MR. GARDNER: I'm sorry. Ask that again.

MS. HYDE: Your tariff sheets talk about when demand and supply don't match. Here in the transmittal sheet it mentions congestion. Congestion may be demand and supply matching at very high prices, and I was trying to get at when are you -- is this going to be used for congestion that may be associated with high prices as well as shortage where there really isn't enough? What is the plan?

MR. GARDNER: Right. I think the only time it would make sense to use it, it would be for a fairly broad area.

MS. HYDE: Fairly broad area with congestion, you mean?

MR. GARDNER: Yes. So like if the footprint -- if the Minnesota/Wisconsin stability interface was the limit, that's a fairly significant limit. It's fairly well-known and if we had trouble on one side of it, we may implement for all the balancing authorities on one side. Something like that. But we haven't defined anything at the moment.

MR. DOYING: It may be helpful to clarify that I think the way congestion plays into there is it is congestion that creates a physical shortage in that subregion. It's congestion that makes you unable to move energy from some place where you may have plenty of supply to get it to some place where you're short. And so I don't think the tariff language even would allow deployment ARC in cases where prices just seem like they're kind of high. You have to have that physical imbalance of supply and demand.

MS. HYDE: That's how I read the tariff language, too.

MR. GARDNER: We wouldn't do it just because prices were high or anything like that.

MR. DOYING: You have to be getting into a position where the UDS cannot solve because there's insufficient supply either in aggregate or from a ramping perspective to solve the cases.

MR. GARDNER: That's right.

MS. HYDE: When you see on plan talk through, you want to make sure -- at least you know what you have.

This is probably Mike Boughner's question from earlier. If not, he can perhaps jump in. Xcel on page 4 of its comments stated that any time the Midwest ISO calls on a market participant to operate in its operating reserve range the shortage condition, that being ARC or beyond, pricing should apply.

The first question we have -- this made us thing about -- could generators be asked to operate beyond their economic max without ARC or the other shortage procedures being invoked?

MR. GARDNER: Not directly. I mean we will not send a base point out higher than the economic max. They are indirectly asked to, when we get into these deficient conditions and we're sending out solutions that essentially require them to manage ACE and go above their economic max to do so.

MS. HYDE: That's occurring within 40.2.15 currently?

MR. GARDNER: Just occurring as a result of the fact that we're sending out deficient solutions because we don't have enough dispatch range for short periods of time and the balancing authorities then maintain their ACE use the regulation.

MS. HYDE: So the short periods of times that's several UDS cycles kind of thing?

MR. GARDNER: Yes, less than an hour usually.

MS. HYDE: What are they paid currently if this happens?

MR. GARDNER: They get paid the LMP at their note against their metered output.

MS. HYDE: Obviously, there's no peaker proxy going on or anything like that?

MR. GARDNER: Right.

MR. MERONEY: But the UVS in that circumstance hasn't set on base points above the economic max, so in terms of how the pricing should be you're not asking, in that sense, for anybody to run above the economic max. So the solution is that you're not --

MR. GARDNER: UVS is not asking them to do that.

MR. MERONEY: Right.

MR. GARDNER: They are being asked to do that in their own ACE equation, though. That ends up happening.

MR. MERONEY: That's what you mean by "indirect." You're basically sending them signals where they're going to be required to meet their standard to essentially run the unit and then it runs at that level, provides the energy in the Midwest ISO and then the actually pricing is based off the offer curve wherever they were actually operating. Right?

MR. GARDNER: No, the price is based on whatever the LMP came out to be in the UVS for that note.

MR. MERONEY: So it's in UVS for that note based on their -- from a quantity standpoint, based on the signal they were sent or based on where they actually operate?

MR. GARDNER: Based on the signal they were sent.

MS. HYDE: So if their costs are higher than that because they're operating above their eco max, that's not reflected in their offer and may or may not be reflected in the LMP.

MR. GARDNER: That's correct. They're not necessarily financially whole.

MS. HYDE: Okay.

MR. DOYING: That is one of the primary benefits of the ARC procedure is to solve that problem.

MS. HYDE: In your answer on page 7, you say that Step 2 may be applied in pre-emergency conditions. However, in Mr. Gardner's affidavit at 7, it says "If Step 1 does not address an imbalance within 60 minutes, the Midwest ISO will proceed to Step 2, which will address emergency conditions."

So how is the proposed tariff dealing with the pre-emergency conditions in which steps?

MR. GARDNER: First of all, we're at our answer -- page what?

MS. HYDE: Page 7.

(Pause.)

MS. HYDE: I'd like you to clearly lay out which it is because I know that you're talking about Step 2 applying in some non-emergency, but I really want you to go through that and lay that out. When is it pre-emergency and when is it emergency between Step 1 and Step 2. And it may not cut cleanly across the two.

MR. GARDNER: Well, what we're trying to do is avoid an emergency, right, by using the reserves to manage the situation in Step 1. If that situation goes on for more than an hour, we've said we would go to Step 2 to continue to use the reserves except we'd price them differently at that point and we'd have access to more of them.

MS. HYDE: And that may still be pre-emergency?

MR. GARDNER: Yes.

MS. HYDE: Right.

(Pause.)

MS. HYDE: I think even in your presentation you have Step 2 labeled as emergency and I think that's the sort of thing -- I think it's a labeling issue that happens sometimes and not others.

MR. GARDNER: Right. The other thing is that, if we're in a situation where 50 percent of the difference is not enough, we would go to Step 2 in order to avoid an emergency.

MS. HYDE: It's still pre-emergency.

MR. GARDNER: Right. That would be another example of that. In the meantime we're bringing on combustion turbines as fast as we can to get out of whatever issue we're in. Did I answer your whole question here?

MS. HYDE: Yes, I think so. I mean I've seen you saying it's not pre-emergency, but I wanted a confirmation of that because some place it says one thing and some place it says another just labeling-wise.

The next question your answer discusses how the proposed procedures extend the scope of the measures by providing Midwest ISO with incremental authority to address reliability conditions before they develop into emergency conditions. This question is from the cynic in us. How do you make sure that there aren't any incentives for you to miss you're forecast, so you perhaps will move into ARC. For some reason you want to move into ARC, is there anything there to make sure that the forecasts are coming in the first day so you don't move into ARC perhaps more often than that once a month or whatever?

MR. GARDNER: I think the biggest thing is the fact that we're going to post every one of these and everyone will be able to see every time that we do it, and people like Mr. Farringer call us when things like that happen as well.

(Laughter.)

MR. GARDNER: I mean there's nothing inherent in any of the procedures themselves that put negative feedback in it, but that's true I think generally in administering the whole market. We try to do it well and tell everybody what we're doing, post what we did and we get feedback before doing things too often.

MS. HYDE: Fair enough. We haven't noticed a lack of feedback.

(Laughter.)

MR. KESSLER: I would add also, going to your notification issue, that tariff language itself requires notification posting on OASIS, so that every time we implement the ARC.

MS. HYDE: Where is that?

MR. KESSLER: It's in Section 40.2.15 -- it's actually the very last sentence, 568.

MS. HYDE: Okay.

MR. KESSLER: So in addition to the prior notification mechanisms that Joe discussed, the tariff also includes a posting requirement.

MS. HYDE: Okay.

MR. DOYING: Interesting to the point we were just discussing, including the existence of a condition requiring it to implement the ARC.

MS. HYDE: Okay. And if you have to say, yeah, you know --

MR. GARDNER: Intentionally.

MS. HYDE: We missed the forecast again.

(Laughter.)

MS. HYDE: Something we noticed in -- a change between the old procedures and new procedures. In the new Step 2, the conditions under which shortage procedures may be implemented are no longer limited to maximum generation emergencies, whereas in the old steps it was maximum generation emergencies. So now it's emergencies. Okay. What other type of emergencies? Maybe you can define for us maximum generation emergency and then define for us what other types of emergencies you think might cause us to need to be in these procedures.

MR. GARDNER: Probably we were trying to be inclusive and to make sure when we had this filed and the tariff was accepted that we could use it for whatever reliability that may come up that seemed applicable. The actual definition of the maximum generation emergency actually is a definition, though, and it is a little bit circular, I think. I was looking at it and it says that "An emergency declared by the transmission provider in which the transmission provider anticipates requesting one or more generation resources to operate at its maximum net or gross electrical output subject to the stress limits for such generation resource and any environmental restrictions in order to manage, alleviate or end the emergency."

Given the fact that we're planning to use this even in Step 2 for a short period of time, if 50 percent is not enough, we're trying to avoid an emergency. We're going to use this for a short period of time. We felt like we should point back to the definition of emergency, which has in the first clause and I can quote it. "An abnormal system condition require manual, automatic action to maintain system frequency" because that's actually what we're trying to do.

I don't know if that answers your question, but that's what we were trying to do.

MS. HYDE: I don't know if it totally -- I guess all the emergencies you see that you would use this for, ones that cause supply shortages of some sort obviously then?

MR. GARDNER: Yes.

MS. HYDE: So it's not the complete set of emergencies, obviously. Who knows what the complete set of emergencies is.

MR. GARDNER: Right.

MS. HYDE: I guess we've moved through this pretty fast. Does anyone else have questions on the stuff we've just been talking on? Or any other questions from this morning as well?

MR. BOUGHNER: I guess, you know, in terms of the procedure that's laid out in the tariff, there's a number of procedures that are out there that are in the tariff in this section that we're talking about or in your emergency operations procedures or your operating procedures or you know, various areas where things are laid out and there's certain things that you probably do that may not even be included in the procedure and I'm just trying to figure out how all these different options that you have to choose from -- in a real time situation you've got an emergency and there's some situation you have to correct for. How you're going to determine which set of procedures or policies or whatever to implement. For example, the offsets that you can put in for the load forecast to get a response from a BA to use this regulation to ramp up above its base point when the market is not able to send that base point to us. Once you implement the ARC procedures, assuming its approved and everything, under what circumstances would you still apply the offset procedures as opposed to going into ARC? Do you think ARC will reduce the need to do that, thereby increasing the number of Step 1 or Step 2 events above the once or twice a month that you possibly envision that you use now? What about the term "local emergency," which is a term we've often heard after-the-fact to describe an event that really affected many only at a certain BA or a certain region of the MISO footprint as opposed to the entire market. Are there certain things that you will do in a local emergency, which is a term that's not defined in the tariff? I'd be interested in hearing how you would define what a local emergency is as well. Would it be different things in those circumstances than you'll do if it were a market-wide issue? Does ARC not apply if it's a local emergency? What are local emergencies? You know, there's just a whole liney of things that I guess less ambiguity in real time. I know that from a procedure standpoint you don't want to be locked into anything that's rigid that you don't have the flexibility in real time to do what you need to do to get through the process in the best way you see fit. But at the same time, in real time there's really no way for participants and even BAs, I think, to really be able to understand what's going on and what to expect after-the-fact from a settlement perspective, from a DCS compliance perspective, from all the other things that come into play when these emergency situations happen.

I guess what we would like to see in the tariff, you know, to the extent that it's appropriate and that's up for debate, I guess, is to really try to tie all these different procedures that are out there floating around -- the EEA Levels Ones and Twos, things of that nature into this step-by-step process that you have so that it's a little clearer as to are you using ARC to avoid an EEA 2? Are you calling it an EEA 2 before you get to ARC? How does all this stuff tie together? That's a terribly long question, but I expect a one-sentence answer.

(Laughter.)

MR. GARDNER: I can tell you that we've committed to -- in your last point with the NERC EEA levels versus the warnings and alerts and events, we're committed to review all of our procedures and tie those back together, which includes a review of potential tariff changes we think is necessary. So we may end up coming back to the Commission with changes to 40.2.15 after that review is done. I don't know that we will at this point, but we're planning to review that before winter to try to tie all those things back together because I agree that it's not as clear as it should be right now.

As far as implementation of ARC, we'll go through that at the Reliability Subcommittee and modify that as necessary. Right now we're planning to use it when we have, I think, two cases that we haven't solved and we don't think we're going to get out of it through the next case we would implement it. That may change over time, but we'll consult with the Reliability Committee on that.

MR. BOUGHNER: Because I think you have the same criteria for when you apply offsets in the weather forecasts. You would apply the offsets.

MR. GARDNER: You have to apply the offsets to get a solution out and the reason that's a good thing most of the time is we've ask the generators -- generators is capable of say going to 800 megawatts and that generator is at 700 megawatts. Okay. And let's say it's the only generator on the system and it can ramp at 10 megawatts a minute. So that means it can ramp 50 megawatts in the next UVS case. Say our requirements is increased by 70 megawatts, but we don't send any solution at all that generator never gets asked to move up what it can move up.

So what we have to do is we have to put the offsets in so we can get UVS to get a solution so we an at least ask it to move up 50 megawatts, which is 5/7th, in that example, of the need. So we're trying -- the reason we're putting the offsets in is to get units moving in the right direction as best we can until we can get other resources online.

MR. BOUGHNER: So you would possibly apply the offsets to kind of prepare the -- get the response you are anticipating you might then need in the ARC procedure?

MR. GARDNER: We would do offsets like we do now, but then when we saw that we weren't going to get out of the issue in that period -- that 15-minute period total -- we would implement ARC. So both would happen. We wouldn't sit there not doing any offsets and then wait to implement ARC. We'd still do the offset procedures for a couple of cases and then we would implement ARC. Does that make sense, Mike?

MR. BOUGHNER: I think so.

MR. MERONEY: Just to follow that a little bit, when you currently do the offsets and people indirectly respond, how is that treated with respect to following instructions as opposed to, under ARC you give them explicit instructions and they would get whatever payments would be appropriate? So what would happen now if they respond to the offsets and then ARC comes in, from maybe a settlement point of view, I'm not sure I fully understand these the way you guys who live with it do. Does that have any implications in terms of what you qualify for and when, what intervals?

MR. GARDNER: It potentially has some, but generally speaking, the assumption is that the units that get moved to manage their ACE when we're in this offset time are the regulation units. This may not be a perfect assumption, but that's the assumption. And they already have their dead band for penalties is already included. The regulation is already included in their dead bands. So if they stay within the regulation bandwidth, they don't have a penalty. That's probably not a perfect -- if they end up getting a penalty of some sort, they have the ability to dispute that. I think that's the only answer we have right now.

MR. MERONEY: It also sounds from the way you described it that since you're having -- if the trigger is you have to go through a couple of intervals that don't solve before you institute ARC that you will have offsets because they're essentially a byproduct of the things that don't solve. Did I do that right?

MR. GARDNER: They're necessary to get -- even they're not a full solution that gets us where we really need to be, they're getting us partway there and they're good.

MR. MERONEY: Right.

MR. GARDNER: So we're going to continue to do them. It's when we see that we're not going to get out of the issue in a timely manner that will implement ARC and use the additional capacity.

MR. MERONEY: All I'm saying is, if you implement ARC, you've gone through a couple of intervals where you already have offsets that you pass onto people, so that ARC means you will have whatever issues might be associated with how you respond to offsets.

MR. GARDNER: Yes, that's right.

(Pause.)

MR. GARDNER: Mark was just reminding me. We did say we would not apply penalties to people during the time we implemented the ARC procedure.

MR. MERONEY: That kicks in for the interval, not the prior intervals as you're currently planning, using intervals that don't solve as your trigger for when you start ARC.

MR. GARDNER: That's right.

I'm sorry, Kevin.

MR. MURRAY: Early on in this discussion of this issue there was an exchange of questions where you were explaining how the interplay between how MISO indirectly ends up having balancing authorities getting the regulating capacity and Bill Meroney asked a question that, I think, clarified if the unit is responding to the actual UVS signal, it gets compensated for its output up to that signal at the LMP, but if it's dispatched and provides regulation, it doesn't get the LMP price for the regulation for a specific task.

MR. GARDNER: Let me clarify. It does get the LMP price, but the LMP price -- when the LMP price was generated, that portion of that unit's offer above its economic max was not considered. It does get the LMP price for the generation above its economic max.

MR. MURRAY: For its regulation output?

MR. GARDNER: Yes.

MR. MERONEY: Presumably, depending on what its offer curve was, had that been accepted, the LMP now may be below its offer, although conceivably it doesn't need be.

MR. GARDNER: That's right.

MR. MURRAY: Another question. You've got multiple things moving and you've got presumably the MISO implements the procedure. You may also have units that were MISO distinguished from a settlement standpoint. What personal unit output was derived from regulation versus what was provided to respond to this procedure?

MR. GARDNER: We don't plan to distinguish that at all. They'll get settled at the LMP.

MR. KESSLER: Just as they do now for the LMP.

MR. HEGEDUS: Mark Hegedus again. With respect to the triggers for ARC, when you were talking about there's been discussions about there being like two UVS periods where you are unanswered. Is that something that can be set forth in the tariff so that's clear as to when ARC gets triggered.

MR. GARDNER: No, I would prefer that we have some flexibility in deciding when to do that, which is why we wrote the tariff the way we did.

MR. HEGEDUS: That's price of having clarity. It's also a limitation.

MR. GARDNER: Right. We prefer to work that out with the Reliability Committee and be able to change that as we see conditions change.

MR. HEGEDUS: How often do you foresee that happening? Is that something you'd come back to the Commission and have changed?

MR. GARDNER: No, it will be something -- right now what our plan is, is we would work it out with the Reliability Subcommittee and implement a new procedure.

MR. HEGEDUS: Is there any reason why you couldn't specify some conditions in the tariff, if you see a change come back and get a new set of conditions?

MR. KESSLER: I thin the tariff does specify a set of conditions. Generally, that's what the introductory language to 40.2.15 says. It's what general conditions and what are the procedures that we would implement in various steps to address those various conditions and I think what Joe's saying is we think those that are specified in the tariff the way they are, which were based on the original tariff language and clarified to provide additional authority prior to emergencies are sufficiently clear in the tariff and will be implemented pursuant to the operating procedures of the business practice manuals as conditions may change that would necessitate us to modify the specific procedures for implementing the general tariff provisions and that's what we presented to the Commission.

MR. HEGEDUS: A different question. Remember when we talked about the notification, it appears at least from the language on page 68 that the notification would go up on OASIS after ARC has been triggered.

MR. GARDNER: Yes. The notification you're talking about, yes. It gets posted and the reason for implementation gets posted on the OASIS. During the event, at the time of initiation, there will be messages sent to the balancing authorities, reliability entities through the messaging system and separately a message to the all the market participants through the market messaging system. So they will know it at the time it happens.

MR. HEGEDUS: How does that notification correspond with timing for submitting offers?

MR. GARDNER: Offers are submitted no later than 30 minutes prior to any operating hour.

MR. HEGEDUS: If you're submitting an offer, preparing an offer, what do you know about the chances of there being an ARC situation.

MR. GARDNER: You don't and neither do we because we did we would take action to eliminate the need for it. These things happen without us knowing about them as well. If we knew it was coming, we would take action to keep it from happening.

MR. HEGEDUS: But the offer, at that point, will already have been submitted.

MR. GARDNER: Absolutely.

MR. FARRINGER: Joe, you mentioned that the trigger that you expect to utilize, or possible trigger, would be two failed UVS cases. You talked about the offsets. Is that a misnomer? Is actually maybe the trigger is really three consecutive offsets? You are going to offset to make a case run. You've stated that there's advantage to at least getting them moving in the right direction. If I get real technical, the trigger really isn't three failed cases. The trigger that mentioned is really three conditions of offset.

MR. GARDNER: Yes, I think you're right.

MR. FARRINGER: If we take that as step further, again, we start talking about UVS penalties and charges. Does it not make sense that if you are entering into an ARC procedure and if the trigger for that is three consecutive offsets, the penalties should be waived for the offsets. And I'm breaking this down in the unusual condition that those offsets occur and the ARC procedure is in another hour which is where these penalties would show up. Is that not something to look at?

MR. GARDNER: Yes, we could look at that. Sure.

MS. HYDE: Do you have a question, Mike?

MR. BOUGHNER: Joe, can you, just some specific detail, can you touch on what MISO considers, status-wise, the capacity that you may call on to commit -- I'm assuming this would be in Step 2 -- maybe in advance of the notification time. You know, if there are units out there and you suspect or hope that maybe be able to start quicker, faster and respond to the event in advance of whatever notification time has suspended the offer you submitted today, you will call and ask them if they can do so. Will do you consider that capacity from the time that it actually does come on until the time that its notification time has elapsed what status do you consider that capacity to be offered in?

MR. GARDNER: Let me make sure I've got this right. This was a unit that was offered as emergency only.

MR. BOUGHNER: No, the unit is offered as an economic unit with a notification time.

MR. GARDNER: Okay, this is a notification time of two hours? All right. We called you and said can you start this unit quicker than that?

MR. BOUGHNER: Right. And just to give an example of why that might over the weekend a unit's not staffed. You've got somebody out to start it. There's two hours, three hours, four hours, whatever built-in notification time to allow for finding somebody, getting them to come out, but maybe the unit has remote start capability and under emergency situations the unit can be started with nobody manning the facility. I'm just giving a real specific example.

(Laughter.)

MR. GARDNER: A hypothetical that I recognize.

MR. BOUGHNER: In those situations, what is the status of unit like that considered to be when you commit it and a participant does agree to start it?

MR. GARDNER: A normal rack.

MR. BOUGHNER: It's considered to be an economic unit.

MR. GARDNER: Yes.

MR. BOUGHNER: So you would not consider for that portion of time until the notification time has elapsed it to be an emergency and would be subject to pricing under Step 2 or any other processes?

MR. GARDNER: No, but I think it's important to note that we're not doing anything in terms of prices to any unit as if it's emergency. We're setting LMP with perhaps a peaker proxy price and people are getting that. But the fact that what units we call on they end up getting a hold on their offer curve.

MR. BOUGHNER: True. But if for an emergency-only unit, a unit that's submitted in the market as a emergency only, you're not going to commit that unit.

MR. GARDNER: Now you've switched to an emergency unit.

MR. BOUGHNER: Right. And now you're going to be substituting an offer for that unit of a thousand dollars for the unit that is started ahead of its notification time. It's whatever its offer was as an economic unit pass its notification time. So what I'm trying to get at is what good does a notification time do?

MR. GARDNER: What I think you're saying, Mike, is we should enhance our offer template to allow you make two offers on the unit. One that's an economic offer of a two-hour notification time or something and another that's an emergency offer with a 15-minute notification time.

MR. BOUGHNER: That would be one way to address it, you know, but I was just wondering if MISO has considered how to handle that in light of the new procedures that are being put in place.

MR. GARDNER: No, we have not at this point.

MR. BOUGHNER: Thanks.

MR. FARRINGER: Jerry Farringer again. One of the things that I'm getting confused with the ARC procedure and when Step 1 versus Step 2 applies, and I go back, the max gen procedures you have in place now. It appears to me, but let's take the case of a curtailment of an import as a footprint. It is clear to me that if we are energy deficient, in other words the system is not in balance and expect to be energy deficient for any length of time that is an emergency situation. If we look at NERC, it starts to lead us to believe that if we are operating reserves for any given period of time, for a lengthy period of that, that is an emergency condition. The ARC procedure actually has us being shy of operating reserves. It has us shy of operating reserves for at least -- well, up to 60 minutes in Step 1 and we have made the statement here that you could be into Step 2 prior to going into the max gen event. What is differentiating between an emergency and what's not an emergency? Where do you draw that line now? Is it just installed capacity or is it system conditions at the time?

MR. GARDNER: I don't know. I think this boils down to what's the treatment that everybody's getting under these various steps. Right. And it boils down to when are we using this for curve price and when are we using that offer curve price and that offer curve price and for how long. I think ultimately that's where we end up. I'm not sure how to answer that, Jerry.

MR. FARRINGER: Joe, I'd take it one step further and let's separate the price for a second. Let's talk about reliability. There's events or actions that can be taken in an emergency and we've already mentioned demand/response being one of them. The question I've got regardless of the pricing, at what point in time should we expect the participants or the footprint to say two hours is a pretty lengthy period of time. If MISO is just making the determination, well, there's installed capacity, it's just a matter of getting it online. That says we're not into an emergency. How long a time?

MR. GARDNER: After 60 we are going to Step 2. At that point in time we have to decide are we now in a situation where a full maximum generation event or are we about to get out of it? But we definitely have to change the price and there's some judgment that we have to apply in terms of what time do we ask you to start interruptible loads and when do we engage in emergency energy purchases. I mean how long is it going to last?

MR. PATTON: You don't necessarily call Step 1 go for 60 minutes and then go to Step 2. If your forecasts are going to be deficient, you'll declare an emergency at that point. Right?

MR. GARDNER: Right.

MR. FARRINGER: What's the definition of deficient? Is it demand versus installed capacity? Or installed capacity that has a reasonable probability of making it online in the next hour?

MR. GARDNER: Yes. We're only going to call Step 1, Jerry, if we think we're going to get out of it within an hour. Now if we can't get out of it within an hour, we'll go to Step 2. But if we think we're going to call these other units on. In the meantime we're going to use the reserves and we're going to be okay in 45 minutes, we're going to call Step 1 and go on. If we're at noon on August 1st then we're looking at hour 1400 and saying we're going to be short in hour 1400, we're not going to implement ARC. We're going to implement max gen event or a warning and then the event if necessary. We're never going to implement ARC. Does that help?

MR. FARRINGER: Yes, I think going toward the path I was getting to anyway.

MS. HYDE: Do we have any other questions this morning?

MR. CARPENTER: I have sort of a clarification question, but in today's world are there any cases where we go into emergency -- and I'll define emergency as not being able to restore the operating reserves within 60 minutes -- that is not related to max gen. It's a spring day, a fall day and you have TLR and at the same time a fuel plant goes down. You've got a lot of things happening. Putting aside all the procedures for max gen, my first question is today can there be Step 2 or can there be $1000 pricing. Second, is that changed at all -- potentially go to $1000 price -- is that changed at all by the new ARC procedure?

MR. GARDNER: No, it does not change. There is the potential. It's unlikely because we have 28,000 megawatts of combustion turbines. So generally speaking, there's enough combustion turbines to get us out of situations. It's possible that bad things happen. It's a Saturday. All the market participants have given us four-hour notification in times or something. It's very unlikely, though. There's a lot of capacity that's generally available.

MR. CARPENTER: It just seemed like there was a lot of -- there was an assumption in some of the questions that emergencies were put over to max gen emergency and it just struck me that that's not always the case.

MR. PATTON: You're thinking of constrained areas as one example non-emergency footprint-wide that we could be in an emergency in a local area?

MR. CARPENTER: Or just the kind of perfect storm case where the load forecast you thought you had enough capacity, the load forecast was missed. You had TLR. Maybe this never happened, but I could imagine there could be a case where you couldn't ramp fast enough. It would take you 90 minutes, say, to get to the full amount of operating reserves that you had to carry and in those types of cases I wasn't aware today you could see $1000 prices, which my understanding was any time you can restore to 60 minutes on the max gen it's clear that there's going to be $1000 prices and Step 2 treatment it was less clear whether that could happen today and if so -- I guess my second question is that nothing changes. The first question is highly unlikely, yes, that could happen.

MR. GARDNER: It's very unlikely given the capacity we have.

MR. CARPENTER: Thank you.

MS. HYDE: Anyone else?

(No response.)

MS. HYDE: I think we will break for lunch. Off the record.

(Whereupon, a recess was taken to reconvene at 12:55 p.m., this same day.)

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

(12:55 p.m.)

MS. HYDE: We'd like to get started this afternoon. We're going to start off with David Patton doing a presentation on the interaction of ARC and market power mitigation, then we'll have more questions.

(Slide.)

MR. PATTON: This is likely to go relatively quickly. I have this presentation that I'm going to go over pretty quickly and be available to answer any questions. This presentation is focused on interaction between the ARC and the market power mitigation. With regard to that interaction, there are really two issues or segments of output that you could think could be affected by the ARC procedure.

One is the emergency output that's released under the ARC procedure. So I'm talking about the output between economic maximum and the emergency maximum and then secondly the non-emergency output. The output ranges below economic maximums that are normally -- normally that's the output that is subject to mitigation under the mitigation measures.

(Slide.)

MR. PATTON: With regard to output that's above the economic maximum, there's no plan right now for the automated mitigation to apply to those output segments. In other words, the real time mitigation software that performs the conduct test and then an impact test on the offer wouldn't be applied to the offers above the economic maximums that are releases. Some of which, obviously, are coming in with the proxy peaker price. Some of which are coming in with a thousand dollars and some of which are coming in under Step 1, a price that's higher than the proxy peaker price under the higher provision that we talked about this morning.

However, one thing that is subject to mitigation -- it's not automated but it's covered by the mitigation measures is people lowering their economic maximum in order to make output unavailable to the market and therefore to raise the price. So while we don't mitigate those ranges when they're released under ARC, nevertheless, it doesn't become a safe haven for people to withhold.

(Slide.)

MR. PATTON: The rest of the presentation talks about how ARC may affect the current mitigation which was really applied to the megawatts below the economic maximum. And generally, what I'm talking about here is the economic withholding mitigation that's supplied in an automated fashion in the energy market. I separate the examples in this presentation into -- I guess there's two examples. One is of Step 2, which is when we're bringing in the thousand dollar output under Step 2 of the ARC. The second one is Step 1 when we're not in shortage condition and we're using the proxy peaker pricing. Because that's a little bit more complicated, I've put that second in this presentation and started with Step 2 which is fairly straightforward.

(Slide.)

MR. PATTON: This figure is a non-shortage condition where I'm showing you the emergency range that could be released at a thousand dollars prior to the demand getting out to that level. Now what this shows is that whether or not they've released that emergency range it's not going to be dispatched and this shows a withholding case where it doesn't really matter what the units are, but there are essentially 10 units that have marginal costs between \$50 and \$60 that it looks like it might be between \$40 and \$50 that are being bid at \$900. So the maroon is the unmitigated supply curve with the \$900 offers in there.

The royal blue is the mitigated supply curve with those \$900 offers set down to their reference level. So you can see that there's a significant impact and those bids would be mitigated and whether or not that emergency range had been released is not going to have any effect on that mitigation.

(Slide.)

MR. PATTON: If you go to the next one, what's more likely is that once they've released the emergency range they released it because they actually need it and in this case, again, the ARC procedure won't have any effect on the mitigation because there would be no mitigation. The price would be set at a thousand dollars under the mitigated curve or under the unmitigated curve. You will have dispatched the high priced offer, whether that offer was at $900 or was at $50. So it has no impact and the fact that the ARC was invoked wouldn't have interfered with the fact that mitigation is applied in this case.

MR. MERONEY: A real quick question so I don't have to ask it later and that is how could the price in that range be other than a thousand dollars if it's set to a thousand dollars. I mean you can't have a thousand dollars as the bid count. Right? I mean in Step 2 you basically say it's the lower of the bid and a thousand dollars, but you can't have a bid above a thousand dollars.

MS. HYDE: Higher.

MR. MERONEY: Higher. I'm sorry.

MR. PATTON: Does it say the higher up?

MR. MERONEY: I mean other than preparing for a higher bid cap, is that any different from saying it's set for a thousand dollars?

MS. HYDE: What happens in a circumstance when somebody's offering 1200, which is above that? Is there any mitigation occurring? You said you aren't mitigation -- I want to clarify this. In the emergency range, what if someone exercises market power during an emergency period by having a bid and its really high?

MR. PATTON: There's a bid cap at a thousand.

MR. KESSLER: You're thinking in the future.

MS. HYDE: So you're thinking that -- the way the tariff reads in 40.2.15 is whatever their offer is, is what goes in. But you're saying offers are already limited by elsewhere in the tariff where it's limited to $1000.

Now, if that were to come up sometime in the future --

MR. PATTON: Yeah, if that comes up sometime in the future, then we're going to need to revisit the ARC, you know, with what happens in shortages, because those two are sort of intricately linked.

MS. HYDE: Okay.

MR. MERONEY: So, essentially, the fees in that range are all a thousand dollars?

MR. PATTON: Yeah. When you're actually in a shortage, then the fact that somebody's economically withheld, won't matter, because you've utilized all the resources.

(Slide.)

MR. PATTON: Okay, so perhaps the more complicated cases, the Step One, so you can -- why don't we go ahead to the figure.

(Slide.)

MR. PATTON: Okay, so, here's a case where we haven't yet invoked Step One, so that the emergency range is excluded from the supply curve, and now you have somebody who is withholding five units, that has marginal costs, I think, of $50 and they're bidding it at $900.

Now, in this case, you have enough ramp capability. The only issue is, that's an expensive offer, and you need it, so you take it and it sets the price at $900.

So this is a case where we haven't gotten far enough for the MISO to release even half the reserves under Step One, and this conduct will have a significant impact on price, and, will, therefore, break both the conduct and the impact test and would warrant mitigation.

(Slide.)

MR. PATTON: Now, we got to the next figure. Once we've released -- well, go back to the previous figure, so that you can understand what's happening.

(Slide.)

MR. PATTON: The reason why mitigation is affected by the ARC Step One release, is, if you look in the blue range, there's a segment of peaker-priced capacity sitting in there, that's going to be released and come in and look cheaper than the $900 offer.

So, in essence, when we do the Step One release, it moves that $900 further to the right, makes it less likely we're going to take it, and now if you go there --

(Slide.)

MR. PATTON: What happens, is that now in the unmitigated case, we take the peaker proxy-priced capacity at $300 here, and the $900 offer never gets taken, so that now the price impact is only $50, rather than whatever it was -- $700 -- $650, I guess -- so you don't trigger the impact test and you don't mitigate the offer that you would have mitigated without the Step One release.

So this is the only impact of the ARC process that I could come up with, that in some limited cases, it could prevent mitigation that otherwise would have occurred.

Now, the reality is, the conduct is, once you've done Step One, the conduct is having a small impact on prices, so it's not as though they're getting away with a price increase that looks anything like the previous figure I showed.

So, it's not -- I don't think anything inappropriate is happening here; it's just this is a possible impact of the ARC release.

I really couldn't think of any other interaction between the mitigation and the ARC.

MR. MERONEY: I'm having a little trouble following from one figure to the next, because I'm not sure we have like a single unmitigated curve or not, and it puzzles me a little bit, about what's happening, say, here.

If it's the same thing -- the red curve is the unmitigated.

MR. PATTON: Yeah, that's the key. The Step One release changes the unmitigated curve. This segment was previously unavailable, because it was in the emergency range.

MR. MERONEY: Okay.

MR. PATTON: And this one is below the emergency, so these two are swapped. So, if you go back --

MR. MERONEY: All right.

MR. PATTON: So, what happens when release this, half of this capacity, is, this segment moves over here, and this one moves out, so you no longer need it, so that the --

MR. MERONEY: So the thing that's not labeled on here, is the thing looks squirrelly, to use a technical term.

(Laughter.)

MR. MERONEY: Where it drops down, because that's where the proxy -- that's a proxy bid that you're putting in there.

MR. PATTON: Well, even if it weren't a proxy bid -- and, by the way, I don't put things on the screen that look squirrelly.

(Laughter.)

(Discussion off the record.)

MR. PATTON: Yeah, even if this were offered, this is the supply curve, as it looks to UDS, and so this is invisible to the market model.

These look like the supply curves that the UDS would see. Once this is released, then it comes jumping in, but, yeah, this segment here is not available, even though it's cheaper than that segment, and it shouldn't be available, because it's our reserves.

MR. MERONEY: Right, but the picture that you're showing -- I mean, that could be -- the lower price could be the result of, say, a peaker proxy coming in at like 250 or something like that, right?

MR. PATTON: Only if the offer associated with these megawatts was even lower than the peaker proxy, right?

MR. MERONEY: Okay.

MR. PATTON: Because it's under a higher-of. The person had attached, like a $500 offer to us, then I would have done this with the segment up here.

But it's certainly going to be no lower than the peaker proxy.

MR. MERONEY: Okay, now, switch to the next one and just -- now what's the relationship between the two?

(Slide.)

MR. PATTON: The only thing that has changed, is this segment right here, that's now setting the price, was an operating reserve segment that you released under Step One, so this was the one that moved, that used to be in the shaded blue area, so it used to be over here to the right.

And this one was over here to the left. Once you release it, then it takes its place in the supply curve, and it shifts the higher-priced offers out, so that you potentially now could have a smaller impact of an offer like that, because you no longer need to take it.

MS. HYDE: So, what's happening in this particular example, is that somebody's reserves between EcoMax and Emergency Max, are replacing somebody's reserves that are under their Eco -- the second person's EcoMax?

MR. PATTON: Well, I would just think of it as just it's replacing high-priced energy, because this was not a -- this was not necessarily a reserve; this was just somebody put in a $900 offer.

MS. HYDE: That's what I meant; it was replacing somebody's capacity that was under their EcoMax.

MR. PATTON: Yeah. Now, what makes this unlikely, is that Step One is not going to be called until MISO gets in a situation where it needs the additional ramp, which means that if UDS has that segment available to it, then it get to it by ramping, and MISO shouldn't have to call Step One, and shouldn't release the megawatts.

It should only release the megawatts, if it gets to the point where it's going into the blue. So this is not a terribly likely thing, but it's possible.

MR. MERONEY: So you will not then -- you won't mitigate things in the emergency range at all when it's called? You had an earlier slide where you make some mention and you said, because the marginal costs in those output ranges are uncertain --

MR. PATTON: That's right. The mitigation we're talking about is the automated mitigation, so that -- I'll give you an example: A lot of these emergency ranges will be on top of a steam unit, so maybe it's the last three or four percent of the output range of a steam unit.

That emergency range will move around a little bit, as the rating for the unit moves around with ambient temperature or whatever.

Now, the actions that a supplier may have to take to get that last three percent, may involve operating the unit in a manner that increases the likelihood of having a forced outage, or tube leak, or, you know, any number of things that contribute to why they would want that in an emergency range in the first place.

And so let's say, under cooler temperatures, the ratings were higher, so that they got a reference price of $50. Well, it's not unreasonable in my mind, that that emergency range is higher up on the unit, so, let's say the true cost of getting that last three percent, is more like $300 or $400.

If the ratings go down, such that now it looks like the $50 reference hits this emergency range, what you don't want is for Joe to release the emergency ranges and then for us to mitigate it to $50 and run it, unless we really need it.

And so I think it's -- I just think it would be inappropriate to automatically mitigate those segments. You know, I would defer to the higher-priced offer that's attached to those megawatts.

MS. HYDE: What if a higher-priced offer is really high-priced? If you're saying you're not mitigating this --

MR. PATTON: Well, we know they can't be higher than a thousand, and at the time they're being released, we're pretty close to a shortage, so that the competitive price, you know, is pretty high, right off the bat, you know, under those sorts of circumstances, so there's not a big -- you know, there's -- it's not as if we're looking a situation where the price really ought to be $80 or $100.

MR. MERONEY: But you still have something in that range. You may have had some operating experience at some point when they operated in that range.

MR. PATTON: Um-hmm.

MR. MERONEY: You may have had earlier discussions from the old cost-based world, where you had some numbers in there for a number of different reasons, right? So it's not that you couldn't do it; it's that you don't think it's advisable, automatically. Is that true?

MR. PATTON: Oh, absolutely, yeah. We definitely could do it.

MR. MERONEY: Right, but do you review these kinds of things in terms of the costs that are associated with them, like these people are, and that's kind of part of a little bit wider question, which is: How do you review those costs and how do you review instances where you might -- and how do you detect an instance where you might have a concern that someone's lowered their EcoMax, for example, essentially to widen the emergency range? I mean, is that a standard action that you do?

MR. PATTON: Yeah, we track, you know, people's ratings and when they're changing their ratings, and how many megawatts they're holding in there, and we also track the reserve levels to identify situations where there's significantly more megawatts in these emergency ranges in a certain area, than the requirement of the reserves for that area, which suggests that at least some of the people, you know, are putting more in the emergency than the reserves that are needed for that area.

What is of much bigger concern than what the price is associated with those, is the megawatts that are in that range in the first place, because it's under 99 percent of the hours. Those megawatts are essentially unavailable to the market altogether, so they're much more likely, you know, in the grand scheme of things, to have a significant impact on prices, just the fact that they're set aside and not available to the market when -- then the price effect that they may have under the limited instances when they're released with a high-priced -- so, you know, I would say we probably scrutinize more, where the EcoMax is being set, and how many megawatts are in that range, than the price that we see attached to the megawatts in the emergency range.

You know, there is nothing that exempts it from the mitigation measures, so that, to the extent they're breaking the conduct threshold in those ranges, they still can be subject to being referred to the Commission, sanctions, and even economic withholding mitigation that's non-automated.

It's the automated mitigation that I think is probably imprudent, because you're letting the software just mitigate it without any review of whether it's appropriate or not.

MR. MERONEY: Do you see any basis for altering in any way, whatever screens you have, or how frequently you do this other kind of mitigation, that would be related to ARC in any way, or would you just see continuing the non-automated screen that you're doing the same way?

MR. PATTON: Yeah, I guess I can't think of any new screens that the ARC procedure would warrant. I mean, the current procedure has the thousand-dollar -- the release of the thousand-dollar megawatts, and the new thing caused by this, is the Step One, so I'm -- yeah, I can't think of any new screens.

MR. MERONEY: Okay. I think that maybe if other people have questions on David's presentation, before we just move on with other issues, any questions?

MR. HEGEDUS: I have one question, David. You made an observation that the price ranges or the cost ranges were likely to be when ARC is triggered, and are going to be quite high, because we're going to be sort of in near-shortage condition.

But does that necessarily apply, for example, to the examples given here today, say, Sunday evenings, where the ramp requirements require rather fast ramp up? Are we really in a shortage situation, marketwide, in terms of capacity, or do we just have to be -- don't have enough ramp at that particular moment?

And so, what does that say about where we are in terms of the cost ranges of these and the output ranges of these units?

MR. PATTON: Well, we're in a tight condition. We're in a tight ramp condition in that case, not marketwide, but, I mean, the way -- you know, ramp constraints can cause very high prices, and should cause, you know, very high prices, when the market is legitimately ramp-constrained, so that in my example here where you take the $900 price before you invoke Step One, there's really nothing wrong with that, if, you know, you're having to go to very expensive supply in order to meet the ramp.

It just sends a signal out there, you know, that we need faster ramping capability. So --

MR. HEGEDUS: Can I ask you about that? That goes to more what is the signal we're trying to send here in terms of getting ramping capability. Why don't we have it and are simply raising the price?

What do you expect to happen? What kind of capacity do you expect to come into the market, what capacity will be made available to the market? Is it going to be the capacity that will solve the ramp problem?

MR. PATTON: Well, it's the right pricing. If I have a unit that is a slow-ramping unit, you know, and let's just take an existing unit that I have some degree of control over how quickly it can ramp.

You know, maybe I can adjust my procedures on how I take mills in and out of operation. You know, maybe there's other things I can do to allow it to be more responsive.

If I'm seeing that there are periods when the prices go relatively high, you know, on a $50 unit, and I'm foregoing significant profit in those periods because it takes me 30 minutes to get my unit, you know, going up, then I'm going to have an incentive to try to increase the speed with which my unit ramps, or, a new unit, when you're making technology choices, you know, you're fundamentally going to be more profitable to have a quicker ramping unit.

Now, to more fully send those price signals, you know, having spinning reserve markets, will be valuable, but, you know, if you're ramp-constrained, there's nothing that argues that that's -- you know, that a relatively high price for a period of when the market is ramp-constrained, is not appropriate.

MR. HEGEDUS: And how will, then, MISO take advantage of that? How will I make that known to MISO, and how can MISO call on me differently?

Say I've made changes in my plant or added equipment, so that I'm more quickly ramping?

MR. PATTON: Well, one of your offer parameters is your ramp, your ramp rate limit, so that feeds into the UDS, so the UDS knows how quickly it can ramp your unit.

MR. HEGEDUS: At that point, if it feeds into the UDS, the UDS sees that, then would the UDS then actually solve, so you wouldn't have these periods where you couldn't come -- where you couldn't solve for the supply/demand?

MR. PATTON: Well, remember, you're one incremental part of a very large system, so that, you know, if you increase the speed with which you can ramp from two megawatts a minute to four megawatts a minute, that's not going to magically solve the ramp constraints for all of MISO, right?

You may have a 300-megawatt unit or whatever, just like, you know, if we were talking about shortage pricing and you were to say, if I'm an investor and I build, then all of sudden, there's not going to be any more shortages, and, therefore, no one's ever going to build, well, you know, it's a very incremental -- it's more incremental than that. It's not as lumpy, so I would think that would particularly be the case on the ramp side.

I can't imagine actions that one person could take, that would provide so much ramp capability to the system, that it just wipes out the problem altogether.

MR. HEGEDUS: But, over time?

MR. PATTON: Over time, you get to an equilibrium, yeah, where probably the ramp constraints bind less frequently, and so people, you know, stop taking actions that would maximize the ramp, and so is stabilizes out.

MR. HEGEDUS: Another question on your statement about whether it's worthwhile. I guess it has to do with the higher -- revising your reference level, and, you know, how in sort of the automation process, you don't have time to go back and check and see if, in fact, the higher bid was as a result of actual higher costs.

Isn't it possible, though, for the owner of the unit to contact you in advance, or could a system be set up so that if you see that you're going into your triggering ARC, that four units that are potentially called upon during ARC periods, say, for those output ranges, that you'd have a separate reference level that would the be plugged into the software?

MR. PATTON: Yeah, certainly people can contact us in advance. As far as -- so, I guess, there's two ways to think about that: One is, as the ratings changed, so that the emergency range is moving to a different place on their output curve, you know, fluctuating, then they could contact us and try to get a reference price adjustment for wherever the range happens to be today.

That seems like a very consultation-intense process, because every time the thing moves, they would have to contact us again.

I think maybe you were thinking also that it could potentially be that there's a second set of reference prices that would apply to the emergency range, no matter where it is. That could conceivably work.

That would require a fair amount of software changes, you know, to develop that and integrate it with the current mitigation software, but that's not -- I can't think of any reason why that would be technically infeasible.

MR. MURRAY: I have a question to the market monitor, but it's more on economics, as opposed to mitigation. I don't know if you're --

MR. MERONEY: You just might be. We can switch over our few questions and kind of go through those and maybe come back to these, and we may cover some of that in the process.

One of them actually is just a sort of followup, maybe more to the IMM. First, I believe your response in the data request stated that the offers that went into the proxy heat rate calculation, included everything, regardless of whether it was -- and I think our question related to conduct, whether it failed the conduct screen -- my first question is, with that, is that also true for any offers that basically had been actually mitigated, that had failed both conduct and impact?

MR. PATTON: Yeah, right now, there's no exclusions that I'm aware of, but that should be confirmed.

MR. MERONEY: That was really probably to MISO.

MR. DOYING: And, Bill, as we responded, we would not exclude -- we would not include any of those offers that failed the conduct test.

Now, your followup question, though, is, what if they have already been mitigated? And that, off the top of my head, I don't know, but we can get you that answer.

The question really is as narrow as what database, specifically, is the data being pulled from, and I'll need to check with some folks.

MR. MERONEY: Now, this is more for the IMM. Do you see any concerns related to that, in terms of incentives to alter your bid at all to influence the heat rate?

MR. PATTON: I guess probably not in the case of mitigation, because mitigation's pretty infrequent, so the idea that that could have a significant effect, or even a noticeable effect on the proxy heat rate, is probably unlikely.

The other question, though, which is what if I have a bank of turbines that I'm virtually certain are not going to be economic, so I just stick in a thousand-dollar offer, knowing that they won't be mitigated, because they're not needed, so they'll have no impact on the market, and so it's sort of a meaningless offer that goes into the proxy heat rate calculation, the question there is, what's the potential cost to me of doing that?

It's probably pretty low, and, you know, what's the impact I can have, individually, on what's the heat rate, well, it depends on who I am and how many megawatts I'm doing this with. For most people, it's probably -- you know, any individual market participant isn't probably going to have too large of an effect, but I wouldn't rule out that that could have some effect.

And then the last question would be, what's my incentive to do that? You know, if ARC is being called twice a month, yeah, then having the proxy price be $10 higher or $20 higher than it would otherwise be, that may not present a strong enough incentive for anyone to really engage in this strategy.

But we haven't done anything that would definitively say they do or don't have the incentive to do that. So --

MR. MERONEY: I'm not sure where that came out, actually.

MR. PATTON: That came out, you know, as it looks to me like it's a very low cost to doing it, and a very low incentive to doing it, so it's sort of -- it may be ambiguous to predict whether anyone would actually engage in that conduct.

So I could conceive of proceeding along the path that was proposed, with the idea of monitoring to see whether this is actually occurring, because it would be pretty easy to change this calculation, if we saw that this was a concern in the future.

It would also potentially be something that I can't think of a reason, you know, a compelling reason to say just exclude everyone from the conduct test up front. You know, that would largely, I think, be a software issue, in that that wasn't how the software was designed to work, initially.

MR. MERONEY: Excluding people, would be a software issue, by and large?

MR. PATTON: Yes, because the software that's been developed, has no exclusion in it right now. And it wouldn't be trivial to exclude on, because our software is doing the conduct test, and somebody else's software is doing the calculation of this number.

MR. MERONEY: The calculation of the proxy heat rate is done every day, but it's after the fact.

MR. PATTON: Yeah, so what would have to happen, is that we would have to be sending an indicator of those units that are breaking the conduct test, which this other software system would then use to filter the offers that it uses to calculate the proxy heat rate, which will undoubtedly cost the schedule a little bit of time.

MR. MERONEY: All right, what difficulties would there be, if any to speak of, in terms of putting in, not automated things, but something at the start of the procedure, to sort of detect things that might indicate the problem that you're -- the potential problem that we identified?

MR. PATTON: You mean, kind of a screen that would alert us if this were becoming a problem?

MR. MERONEY: Um-hmm.

MR. PATTON: That would be pretty easy.

MR. DOYING: You'd do after-the-fact analysis and report on that.

MR. MERONEY: I'm assuming, also, that the offers cover the full range of the unit, so they include the emergency range, as well, in terms of what goes into the proxy heat rate; is that correct?

MR. DOYING: No. The proxy heat rate actually calculates between the economic minimum and economic maximum, but are offered into the market, so it's based on the economic offers of those units.

If you look at the formulas that we -- the ones that had the actual equations that actually shows that in more detail than you'd possibly want to see.

MR. MERONEY: I know, and I unfortunately have a question or two on that very subject, that I was thinking about leaving for the end, but then everybody would either leave or fall asleep at that point.

But with the idea of trying to make it a little quicker, I've actually made copies of the formulas, which we can hand out, take a look at -- let me have one of these.

(Documents distributed.)

MR. MERONEY: They are actually fairly short, I hope, because they are largely questions of clarification. And it may just be that I am misreading some of these details. And while I would love to take this off-line because I don't think they are that significant, it seems inappropriate to do so.

My first question has to do with the monthly Peaker Proxy Heat Rate. And just looking at that, it looks as if it's an average overall offers, an unweighted average, so it's just each offer counts as one?

MR. DOYING: For the monthly, yes. For the daily average it's a megawatt-weighted average. So when you get to the daily calculation, it then is rolled up to take the monthly. It is a megawatt-weighted average.

MR. MERONEY: So what's happening is in number one on page 4 here--

MR. DOYING: Right.

MR. MERONEY: The Average Daily Proxy Heat Rate going in here is--

MR. DOYING: Is megawatt.

MR. MERONEY: --weighted.

MR. DOYING: That's right.

MR. MERONEY: But then it's just over--

MR. DOYING: Over all the hours. So we've normalized for megawatts on the Daily calculations, and taken out of the equations on the Monthly so we can safely ignore it.

MR. MERONEY: Okay. Then the other question here is when it says: The Offer Count is the total number of Hourly Real-Time and Day-Ahead Peaker Offers over the 30 days?

MR. DOYING: Right.

MR. MERONEY: So this is, you're including both Day-Ahead and Real-Time?

MR. DOYING: Correct.

MR. MERONEY: So for the same unit you would have a Day-Ahead Offer and then a Real-Time Offer, potentially?

MR. DOYING: Correct. That's correct.

MR. MERONEY: So you're just pooling everything--

MR. DOYING: That's right.

MR. MERONEY: --putting it in like a big pool of all these offers.

MR. DOYING: Right. Again, we want the broadest data set to be as representative to avoid problems like a single-unit, to David's example I think on your ability to influence that price. We have 28,000 megawatts of capacity times a couple of offers a day times hourly offers. I think your ability to significantly change that average value we calculate as pretty minimal for a single --

MR. MERONEY: In fact, part of the intent here is to dilate individual offers as much as possible?

MR. DOYING: Absolutely. And to make it as representative as possible by increasing the sample size.

MR. MERONEY: Going over to, on the following page on page 5 for the Average Daily Proxy Heat Rate, I note that the summation across, or the costs are divided by 24 times the gas price. Is it assumed then that there are 24 hours of costs always summed for every offer?

MR. DOYING: Right.

MR. MERONEY: And that exists? There's no--you don't have situations where an offer might get pulled somehow in the middle of the day so you only have 12 hours for a particular offer, and then you ended up dividing by 24? Like a Real-Time Market, or something like that?

MR. DOYING: We calculate an hourly weighted average price and then divide through by that daily gas price after we have a total hourly. So we calculate all the offers that we have hourly, and then divide through by the 24 hours.

MR. MERONEY: So you're basically going to hourly--I was just concerned with the 24 in there, but okay.

MR. DOYING: Right.

MR. MERONEY: All right. I'm pretty sure I follow you on that one.

And then my final detail clarification question just is: I like it that you found the integral sign here because you don't get to use that very much--

(Laughter.)

MR. DOYING: I actually disliked that piece. It's been way too many years since I've solved one of those.

(Laughter.)

MR. MERONEY: Yes, well, number two seems straightforward enough because it's incremental energy costs.

MR. DOYING: Right.

MR. MERONEY: I was just a little puzzled by--and maybe I'm just thinking this wrong, and you mentioned it before--this integrating the start-up costs over the economic range?

MR. DOYING: Right.

MR. MERONEY: Isn't start-up cost a number to start up?

MR. DOYING: Sure. It's a single value, but given that we have the whole dispatch range to work with, when you take that single number for a start-up cost and you want to calculate an average value, it would be a different number if you divide it through by the EconMin versus the EconMax, because you're turning it into a dollar-per-megawatt number; right? So you have to take out that range piece that you're doing the evaluation over EconMin to EconMax instead of at a single point.

In the simple example in the presentation we looked at earlier, we were assuming actually there was only one point on the dispatch curve. And in that case, you can take the start-up costs and say, yes, that's the right average for that whole dispatch range. But it's not the right number if you actually are trying to calculate an average price that reflects the average for the unit at all of its dispatch output points.

MR. MERONEY: For purposes here--and I won't go further unless somebody else has questions, but I suspect that if it really is a single number, the integral probably falls out of the calculation pretty easily.

MR. DOYING: If it was a single number, yes.

MR. MERONEY: Yes. Well, a single number for start-up no matter where you put it. The start-up doesn't vary--there is a single number for start-up, isn't there?

MR. DOYING: There is.

MR. MERONEY: Right. Okay.

MR. DOYING: There is.

MR. MERONEY: All right. That's my question from this piece of paper. It was really just a clarification of those issues.

Now we have the details out of the way, I would like just to run through, I think you have touched on it, David, and you touched on it in your presentation, but just to run through one more time the basic reasoning behind adopting the proxy price once you do ARC for Step One.

MR. DOYING: The basic rationale again?

MR. MERONEY: Yes. Just go back through the basic rationale.

MR. DOYING: Sure. It's to assure that when we release that reserve capacity that the prices that then clear in the market reflect the fact that we are in supply scarcity. And we could pick an arbitrary number. In fact, some of our stakeholders suggested that this calculation seems awfully complicated; can't we just call it $500?

We picked a number for the upper level at $1000 that's based on the Offer Cap. Why go through all the trouble of calculating a number. And, while we want it to reflect supply scarcity on the system, we want it to reflect the actual costs that you would get for that supply scarcity, which is fairly represented by a peaking unit on the system, which is why we use an average proxy peaker, the higher of that price for the offer price.

So we don't want prices to fall when we release operating reserves, which they could if you don't price them appropriately; then you're sending the wrong economic signals. So to assure that the prices accurately reflect the scarcity, you need to have an administrative determination of the price in setting it at the cost that you would have but for the reserves. The peaking capacity if you could get it on line fast enough seems like the most reasonable price to establish.

MR. PATTON: Yes, that's the real key, you know, this capacity is really--the alternative to utilizing this capacity is to utilize more peaking resources. So it's sort of a tradeoff and you're trying to price it at a level that reflects the opportunity costs of what you would otherwise use.

MR. MERONEY: So what other consequences are there if you just--other than prices might fall?

MR. PATTON: If you just let it come in at their offer?

MR. MERONEY: Right.

MR. PATTON: I think it's basically a pricing issue. This provision in my mind exists almost entirely to ensure that your prices are efficient during these periods.

MR. MERONEY: Is there any potential to confuse the dispatch?

MR. DOYING: Sure. I was going to say, when we say there's just a pricing consequence, that's true. That's how you actually see the outcome. But that has lots of important consequences for the market in terms of how people will offer, knowing that if we get into that situation prices are going down rather than up, what that means with the relative efficiency of the Day-Ahead versus the Real-Time Market when we have the wrong prices at the wrong time and real time inconsistent with the way the Day-Ahead Market has cleared.

There's lots of reasons why getting the price right is important.

MR. PATTON: And you're right. It will affect the dispatch because you'll now potentially back off of higher costs economic megawatts and replace them with lower cost reserve megawatts, which is not a good idea. Because ultimately when you come out of this thing, you're going to want to go back the other direction so that potentially you're going to be ramping down somebody quickly who has a high-priced offer, and then having him ramp back up 20 minutes later when you get back out of ARC.

So there are sort of operational issues and dispatch efficiency issues in that.

MR. MERONEY: Does it change anything other than when you put the proxy price in, it doesn't change any of the other rules about what can set the price? Right? So if you had issues before with peakers that couldn't be dispatched and, or things that were ramp-constrained and couldn't be dispatched not being able to set price; those are still there, right? Just that?

MR. DOYING: Sure.

MR. MERONEY: Anything in this range now, to the extent that it's dispatchable, will be able to set price; right?

MR. PATTON: Yes. I think it helps from that perspective when there's an actual release because it makes it--because a lot of these megawatts are on steam units in flexible ranges that it will better ensure that the price is actually going to be set in that range which, you know, it's all too frequent that when we're into using our peakers the price is set significantly below where the peakers are offering so that we end up with the peakers being out of merit and RSG.

So that this will bring in more flexibility in the range where prices really ought to be. So it will help when release actually happens, but it won't--other than that, it won't change any of the rules that would otherwise apply to the inflexible units, or units that are at minimum.

MR. MERONEY: You mentioned before that there are a lot of factors in terms of the high-end of the range here in terms of how somebody might set price, and the difficulties of using a cost basis for that.

What is your experience in terms of where the resources in the emergency range are currently priced? Are some of them higher than these numbers? I think in an emergency range there could be a number of issues that might affect pricing. So do you have a sense of how the price may play out for the use of these resources?

MR. PATTON: I would hate to speculate off the top of my head, but we could--I could certainly get you some information back on that.

MR. DOYING: Bill, one thing that will be difficult when interpreting the current set of offers in that range is they are currently not used for any dispatch purpose. So that to the extent there are numbers there at all, they don't reflect market participants' evaluation of the consequence of the unit being dispatched in that range with the ARC procedure put into place. People will actually have to evaluate what the sensible offer looks like over that range, and offer-behavior may well change once we actually have the ability to dispatch into that portion of the unit's output range.

MR. MERONEY: Without--I don't know whether it's appropriate to say what we think would be good to see or not see here, but I mean it might be worth a look, but I understand what you're saying because I've seen some of those numbers and they do reflect often the very, very high end of a range even and some of the cost-bases could be very high. I understand the difficulty.

You answered one of my questions before, which was when you go to Step Two is the bid price other than $1000? And the answer seems to be: No.

Is the current Step Two really just a--and the basis for the $1000 is the continuation of the current process where you change it when it applies and does it change the process where the price goes to $100 for dispatch in that range?

MR. DOYING: That's correct. I think the two big changes here are the Step One, which is different, and some minor changes in the criteria for getting into Step Two. But the pricing and dispatch in Step Two are identical to the current.

MR. PATTON: And the logic is the same. There are some thing that were unclear about the steps that were in the prior Tariff that have all been cleaned up in this one.

MR. MERONEY: Whatever the logic of having the price go to the maximum is essentially the same logic that underlies the current.

MR. PATTON: Yes.

MR. MERONEY: My last area of questioning really has to do with RSG. I think you addressed some of those in your presentation. One of the areas we looked at was Ron

Macnamara's affidavit here where there did seem to be a fair amount of emphasis on the importance--on reducing RSG because a high percentage of the total RSG costs are incurred from having units online in anticipation of being used for infrequent supply conditions.

Is this the area that you're suggesting is not the primary area that you would not really be able to address until you had some experience with the current ARC without any alteration in the commitment decision?

MR. DOYING: Yes, I think that's right. As we said earlier, we can directionally say that is the effect, that's how the effect would play out as it provides better opportunity to reduce the amount of head room, but until we have some experience, until we work with folks like the reliability subcommittee on defining exactly how this gets used, when it's deployed, it will be very difficult to quantify that.

MR. GARDNER: But it will definitely have a positive effect.

MR. DOYING: Sure. But directionally we know what the outcome is. It's the order of magnitude that is difficult to estimate.

MR. MERONEY: My recollection is it may have been a state of the markets, or some other presentations, but I don't believe it was in any of your filing that would at least give some sense of a magnitude of the kinds of commitment, and the level of commitment. I don't know how that's changed over time. Of the units that give us a sort of a sense of what the total pie is in terms of how many of the RSG costs arise from those sorts of commitments. Is that a number that can be at least gotten, a ballpark?

MR. PATTON: Yes, a ballpark is, you know, something like 75 percent of the RSG is associated with the commitment in real-time of peaking resources. So those are almost entirely the commitments that are affected by having the ARC Step One available.

So peaking resources produce about 2 percent of the energy in MISO, but they're the majority of the RSG because of their inflexibility and because of their general cost structure.

So in my mind there is a fairly direct relationship between having Step One available and the commitment of peakers.

MR. MERONEY: And that would then, you would anticipate then that you could commit fewer peakers with the idea that you could then use some of these other resources for those, the ARC kinds of conditions?

MR. GARDNER: Yes.

MR. DOYING: And, Bill, just as importantly, making sure that the prices are correct when we use ARC will reduce the Make-Whole Payments necessary to the other peaking units that are online at that time. That is one of the sources currently of the RSU for those units, is that because some of the units for example are not eligible to set price EcoMin equals EcoMax, as David said the market-clearing prices can be well below the offer. So even though the unit is needed, needs to be online for energy production, it is still not covering all of its costs, generating the need for a Make-Whole Payment.

Assuring that prices during scarcity conditions actually reflect those conditions will reduce the Make-Whole Payment levels necessary for the units that are committed at whatever the right level is for those commitments.

So you reduce the megawatts committed and reduce the payments necessary to those units.

MR. MERONEY: Well you reduce the RSG costs by basically raising that--five-minute prices in real-time.

MR. DOYING: That's correct.

MR. MERONEY: So depending on who I am and how I'm participating in the market, that may or may not be a net positive, right?

MR. DOYING: It should be a net benefit in either case, right? If we're committing fewer resources, we're lowering production costs on the system.

MR. MERONEY: But if I'm looking at buying at whatever the stream of real-time prices is as my starting point--

MR. DOYING: Well it's the stream of real-time prices plus the RSG that you'll incur, as well.

MR. PATTON: I mean, if you need peakers and they don't set prices so you have to pay them with RSG, then what you can say is that real-time prices will tend to be understated causing people to buy less in the day-ahead markets. And ultimately then the real-time price benefit is offset by the fact that you're allocating additional RSG.

And in any case, you know, there's no way to argue that that's--even if it is lower, and even if someone somewhere is benefitting, there's no way to argue that that's a more efficient result. So, yes, it seems clear that wouldn't be in the public interest even though it's technically lower.

MR. DOYING: Maybe another way of saying that is, though you're probably right that for an individual market participant they can say this doesn't look to me like necessarily reducing my costs, but for the market overall it is a much better outcome.

MR. MERONEY: Do you see any pattern in the way that might be distributed across market participants? Would it be good advice if I were concerned here?

MR. PATTON: I mean this phenomenon, this phenomenon of setting the prices at a more appropriate level when the release is happening, that is happening in a very-- you know, if it's once a month that's a pretty limited set of circumstances.

Perhaps the larger RSG impact of operating at a sustainably lower headroom, to the extent they are able to do that, that seems like it benefits everybody.

MS. HYDE: Are there questions on this topic? Kevin?

MR. MERONEY: Pretty much now, without rehearsing the day, we'll start with this topic. But everything that we've covered since David's presentation.

MR. MURRAY: I just have two questions that are actually a follow-up on some of the questions that Bill was answering.

Obviously as conditions evolve there's a tradeoff that is being looked at in terms of avoiding committing units upfront and being able to rely on ARC procedure. Does MISO have any operating procedures defined at this point to actually ensure that the dispatching that occurs will be at the lowest cost to consumers, as opposed to lowest cost to producers?

MR. DOYING: Kevin, you said the dispatch that occurs?

MR. MURRAY: Yes.

MR. PATTON: After the release?

MR. MURRAY: Well, I think what Bill alluded to here, there would be a tradeoff. You're potentially setting up a procedure that says we are going to reduce RSG costs at the expense of increasing LMP peaks.

Now we can step back from all of this and say, at the end of the day what's the lowest cost system dispatch? And there's two ways to look at it. The lowest cost to consumers versus the lowest cost to producers. And I get two different answers depending which question you ask.

My question is: Does MISO have any operational procedures to in fact ensure that the dispatch that ultimately results is at the lowest cost dispatch to the consumer?

MR. GARDNER: I don't know that I have a procedure, Kevin, but your suggestion is that we should commit more and more peakers and keep driving the LMP price down.

MR. MURRAY: I'm not suggesting it. I'm suggesting that there's an economic tradeoff, and at some point there's an equilibrium point.

MR. PATTON: Well, I view it as there is an appropriate objective function to the market. And that is, generally to maximize surplus to everybody. And generally in these markets what that means is minimizing production costs.

That is not the same as minimizing costs to consumers, because minimizing costs to consumers would include minimizing prices. So the most efficient dispatch is one that minimizes production costs, not prices. And that the way all the MISO market works across the board, and that's the way all the LMP markets work.

So in this case, nothing is really changing about that. The only way in which there's a new twist is when do you active ARC Step One? And are you getting a lower cost solution, a more efficient solution?

And there the tradeoff is between the costs of committing inflexible peakers and maintaining a slightly higher headroom versus temporarily sacrificing some of the reserves. So that would really--but that's not a cost to consumer issue, so I'm not sure that's what you're even asking.

MR. MURRAY: We could debate this, what's the relevant merits of a particular dispatch. You are suggesting MISO dispatches to the lowest producer cost. My question was really what operational procedures have been defined? And if the answer is, none, that's fine.

MR. DOYING: The operational procedures are the ones that are already defined and already in the Tariff and in the market systems. That is, there is a least-cost dispatch performed on a five-minute basis based on the offers that are submitted.

It's a mathematical algorithm. So maybe I'm just not following the question?

MR. MURRAY: Let me ask a follow-up question. Obviously there's a tradeoff that's occurring between incurring RSG costs, commitment costs versus how high we'll drive LMP prices in real-time.

On an after-the-fact basis, what performance matrix does MISO or the IMM plan to employ to look at whether the results are consistent with producing an objective of least-cost to consumers.

MR. DOYING: Kevin, let me back up by saying I don't agree with the premise and let me tell you why.

There isn't a tradeoff here between the prices and the dispatch. You're suggesting there's a tradeoff between RSG that's generated and how LMP prices could go.

Let me step back to a hypothetical and then try and bring it back to where we actually are. In an ideal world where there was no uncertainty about future changes in demand and no uncertainty about changes in import/export schedules, we could operate on practically zero headroom. You'd still need a little because you've got ramping start-up kinds of issues, but it would be very small. And that would be the most efficient commitment at that point.

The commitment you're aiming for is the lowest cost commitment in order to meet that required demand. Now the fact that we do have uncertainty means that commitment has to increase. But it has, by definition, an inefficiency in the marketplace caused by the fact that we don't have perfect knowledge. It's a known. It's a well understood inefficiency, but it's an inefficiency introduced by a perfect world.

So there is no tradeoff between we'd like to have RSG lower and we're willing to buy that with higher prices, the answer is we would like not to have to commit any more resources than absolutely necessary because that's the right economic solution to the question of how to best allocate resources.

And that is the objective that we are heading for, and the whole Tariff and all of the market systems are developed around that notion.

MR. MURRAY: But I thought this was what was in the affidavit. It was identified that when MISO commits resources on an upfront basis, we incur RSG costs.

MR. DOYING: Sure.

MR. GARDNER: Maybe.

MR. MURRAY: Maybe.

MR. GARDNER: We have the opportunity to.

MR. MURRAY: The more up-front commitments we do in anticipation of the unknowns, the higher probability of higher level of RSG costs. Nothing is an absolute. Everything is a relative. But I'm making that decision, and now in the context of the ARC procedure I'm suggesting that, as a result of MISO having this additional tool, all other things being equal, I think over time I'm going to be able to reduce the level of up-front commitments I'm making. I'm going to reduce that 700 to 1000 megawatts that I'm carrying day in and day out, and my question in all this is:

What are you going to look at on an after-the-fact basis to see if this tradeoff that's being done is producing lowest cost.

MR. DOYING: And again, Kevin, by definition if we could get headroom to zero we would be there. That's the metric. There is no other analysis that's needed. We are committing and dispatching on a least-cost basis. To the extent we have to commit any additional capacity, it's an expense to the market place.

So what you would like to do is drive that down to zero, which would give you the most efficient economic outcome. You don't need to look at any other sides of the coin. There just aren't any.

MR. MURRAY: So what you are saying is, in MISO's view if RSG costs are zero, it's irrelevant what LMP prices are?

MR. DOYING: No, it's not irrelevant. But the market rules that are defined for how those prices are established assure that the prices that are established under the supply and demand conditions are in fact reasonable. They don't reflect market power. They reflect competitive outcomes. Those are the outcomes that you're looking for.

So, no, I wouldn't agree that prices is not of any concern. It is. And that is why you build the market to assure that you do get competitive outcomes. It is competitive outcomes that we're looking for, and we know that if we design the market correctly those will minimize the costs. And, as David said, maximize the welfare that's available to be distributed to all participants in the market.

MS. HYDE: Do we have any other questions? Yes?

MR. BOURBONNAISE: One other comment to that. There is one other side to this coin, and that is reliability.

MR. DOYING: Absolutely.

MR. BOURBONNAISE: And that's been kind of ignored in all of this discussion.

MR. PATTON: Yes, in fact I was going to make that comment because--

MR. GARDNER: Well, let's not say it was ignored, Bill. I mean the whole reason we're here is because the operations--at least we have a reliability issue that we're trying to solve. That's what we're trying to solve.

MR. BOURBONNAISE: We view this as an economic discussion, which it has been all day--

MR. DOYING: Well it has been since lunch.

MR. MERONEY: We talked a lot about reliability this morning.

MR. PATTON: Yes, to connect the dots, but there is one thing that--one other thing. We talked about the trade--the real tradeoff is, is it more costly to utilize some portion of your operating reserves for a small period of time, or to commit peaking resources.

Obviously the conclusion under Step One is: It's a better solution to use, under some circumstances to use some of your operating reserves for a brief period of time than to commit peakers. But the second--it's not just the commitment of peakers, it's the use of the regulation up that, without ARC Step One that you're going to be using, and lastly the cost of the frequency fluctuations that, without ARC, you experience because your regulation isn't capable of keeping your frequency from fluctuating.

So, you know, there are sort of, I would say, three classes of costs that the ARC Step One is helping you avoid. And if you're convinced that the cost of not having your operating reserve for the brief periods of time, or that cost is lower than these three other classes of costs, then I would agree with Richard that I'm not sure what analysis, other analysis needs to be done.

MS. HYDE: Other questions?

(No response.)

MS. HYDE: Oh, you all get out early. Okay, I wanted to remind you--I want to thank you all for coming. This has really been helpful to Staff to get these answers laid out for us. This will help us process the filing.

I wanted to remind you, we have comments due after the Tech Conference on October 12th, with reply comments on the 19th.

As Staff, I can say we would appreciate not to hear a complete rendition of your previous comments again. We do have those. We are going to be using the previous comments. To the extent you can add more, that would be really what we would like to see.

Is there anything else?

(No response.)

MS. HYDE: We are adjourned, then. Thank you all very much for coming.

(Whereupon, at 2:05 p.m., Tuesday, September 26, 2006, the technical conference was adjourned.)