Bonneville Power Administration
BPA-EIM 101 Workshop
Presenters: Steve Kerns, Todd Kochheiser, Russ Mantifel, Frank Pulyeart
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STEVE KERNS: (In progress) – our EIM stakeholder series that we're hopefully going to establish to be monthly. My name is Steve Kerns. I'm the director of grid modernization at Bonneville Power Administration. We really appreciate the time that you're taking to come join us today and participate on the phone. We're not intending to get into policy issues. This is really intended to really focus on how the EIM functions and works to make sure everybody is on the same page. Today's workshop also will be taped for the purpose of developing an EIM 101 video that will be used for training purposes.

We have a pretty big agenda here. There's a lot of ground that we're going to cover. Our intent here is to cover all of these things. We're going to take a 10-minute break at about halfway through. I think this presentation can go one of three ways. We could charge through this with minimal questions and be done in a couple hours. We could get slogged down in a bunch of Q&A and kind of get lost.

I'd like to steer this to the middle and have a perfect amount of time for presentation and just the right amount of time for Q&A. So, I'm going to be monitoring the time pretty closely. What we'd like to do is have a short chance for Q&A after each section and then at the end we're, hopefully, going to reserve 20 minutes or so for more broader questions and answers. Just also a reminder that there's a sign-in sheet at the back of the room and we'd appreciate it if you could sign in.

We also are doing this on WebEx. Just a few reminders for today's meeting. The link is available on our event calendar and we know that there's been some challenges getting started here, so Kevin has issued – was just on a second ago, to tell you what to do to get the latest and greatest on the link. Safety is a big topic for us here. We take it very seriously. If there is an emergency, please follow your neighbor out of the room, down the stairs, and across the street to meet in Holiday Park which is across from where the Max station is.

For WebEx and phone participants, all call are muted on entry, so if you have a question you will need to unmute by using *6, then please identify your name and let us know who you represent before you ask a question. That goes for those of you in the room as well as on the phone. Finally, please do not put this call on hold or take other calls while you are dialed into this one. If we identify a noisy line you will likely be disconnected from the meeting.

Like I said, there's a lot of materials here that we intend to go over. I think I've already touched on all of these, at least the top three here. Any feedback that you come up with after the fact feel free to send it to the email address techforum@bpa.gov and reference the "EIM 101 Workshop."

Upcoming stakeholder meetings: We've got one scheduled right now for October 11th 9:00-12:00. We've heard some concerns about that conflicting with some other meetings, but right now this is the time we've got planned for the next two. We'll have more information about topics and tentative agenda items for that as we get through the next couple of weeks. And for more information please visit www.bpa.gov/goto/eim.

The purpose of this meeting is to provide a common understanding of how the EIM currently functions so that everybody in terms of stakeholders, not just our transmission customers but the corps and the bureau, can engage in future meetings and workshops and also to help identify policies and business practices that may impact BPA's potential EIM participation and to that and really help inform how we want to direct these future customer stakeholder workshops over the course of the next several months.

At the end of the workshop, you should be able to understand at a high level what the EIM is and what it is not, the roles and responsibilities of the market operator and the BA, and also the market participants, a high-level understanding of the major processes and the market timing associated with how resources are bid into the market as well as some resource efficiency aspects and there will also be a bit of a discussion on settlements and how they work.

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There's also a couple links at the bottom here for additional resources that are available and quite a bit of information is in the appendix of this presentation as well.

So, with that I will hand this off to Todd Kochheiser from Transmission Operations, our resident expert on how the EIM functions and he will be leading today's workshop.

TODD KOCHHEISER: Yeah, thanks. Can you guys hear me okay? Good, I'm going to stand, otherwise I might fall asleep. And, fortunately for all of you, I will not be monotonally talking for the next three hours. I have some other speakers that are going to help me today. One is Russ Mantifel, he'll be talking to the governance in transmission slide as well as Frank Pulyeart over here. He'll be talking about resource efficiency, an area he's been studying.

So, let's go ahead and start here with a little bit of background on the CAISO and Bonneville. We're not going to dwell on it. If you have actually any questions about the California ISO, we have two people in the room today that can answer those questions for you, Don Fuller and Milos, which many of you probably already know.

So, the California ISO is one of nine independent grid operators in North America and it's also one of 39 balancing authorities in the western interconnection. It operates whole electric Day Ahead and Real Time markets, it manages the transmission grid in California as well as interconnection of new generation grid expansion projects. And for today's topic, they are also the operator of the Western Energy Imbalance Market. I don't think we have any questions on who they are. I could stop, but I'm not going to.

The Bonneville Power Administration, just to level set everybody, we are a Federal Power Marketing Agency located in the Pacific Northwest. There's a bunch of stats there in very small font, a bunch of impressive numbers. Many of you already know who we are, but we cover over 300,000 square miles as far as our service territory is concerned.

We have 15,000-plus miles of high-voltage transmission from 115 kV and up. And we market and deliver the energy from over 31 federal projects or dams. If you blow that up, you can read all those details as well.

This is generally kind of a blown-up view of our service territory. You can see essentially the high-voltage transmission system and all the federal projects on there as well. I don't think there's probably any questions about BPA, either, but if there are, I will take them now. No? Okay.

Well, one thing that I've experienced in other meetings, there sometimes isn't a base-level understanding of what a Balancing Authority is and a Balancing Authority is an important concept for the energy imbalance market. So, there's just a couple slides here we're going to go through quickly.

First of all, what's a Balancing Authority? It is an entity that integrates resource plans ahead of time, maintains demand and resource balance within one or more Balancing Authority Areas, and supports interconnection frequency in real time.

And that's a little different than what the Balancing Authority Area is. That's a collection of the generation, transmission, and load within the metered boundaries, so those are often called interchanges or tie-lines, of the Balancing Authority where load/resource balance is maintained.

So, this is a distinction that's interesting in that you can have the Balancing Authority and actually have multiple Balancing Authority Areas and PacifiCorp is an example of that.

Now, there's 39 Balance Authority Areas in the Western Interconnection. They're interconnected, but they generally operate independently. And the Balancing Authority Area is managed by a system called Automatic Generation Control. So, it manages the BAAs Area Control Error.

This is the equation. It's long. I kind of grayed out a few sections that aren't that interesting, but in essence, your ACE, or your control area, and your Balancing Authority is the difference between your actual metered interchange and your scheduled interchange. The actual interchange includes all those pseudo-ties and tie-line meters with your adjacent Balancing Authority. So it's the net of all those. And the schedule interchange is the sum of all the scheduled megawatt transfers including Dynamic Schedules which is important in the EIM with all your adjacent BAAs within the same interconnection.

And then there's a second part of the formula, this -10B (FA-FS). This is the component of your ACE that is there to allow you to essentially support the interconnection frequency. So, you're going to have a frequency bias that every Balancing Authority has a different one. And as the actual frequency deviates from scheduled frequency, your ACE will increase or decrease and at some point you're going to control and hopefully contribute to the correction of that frequency error.

This is what Bonneville's Balancing Authority Area looks like. It's the area in green. So, it's essentially the metered boundaries of Bonneville's Balancing Authority. And overlaid on top of that is Bonneville's high-voltage transmission system, 115 kV and above, again, a lot of those federal hydro projects that we market energy from.

You can see that's a little bit different than our service territory. This is the actual Balancing Authority Area. And you can see there's little spots in there that are not green. Those are the other utilities like Portland General Electric, PacifiCorp, Vista, et cetera – Idaho Power.

And currently today, Bonneville has 253 interchanges or tie-lines with 18 adjacent Balancing Authority Areas. And that number is, I think, going to go up to about 268 by the end of the year. So unlike some Balancing Authorities that might just have a couple tie-lines. Any questions about Balancing Authorities that I'm probably not qualified to answer, but I'll try anyway. No? All right.

Moving on, what's the EIM? That's why we're here today. This is the short, pithy answer, I think. It's an intra-hour, so sub-hourly, or real-time centralized energy market used to economically and securely dispatch participating resources to efficiently balance supply, transfer between Balancing Authority Areas. They're also called EIM Entity BAAs, and the load across the market's footprint, the EIM Area. We'll talk more about EIM Areas and EIM Entities more throughout this presentation. And it does all this every five minutes.

And it's an extension of the California ISO's Real-Time Market. Generally, as California being responsible to a lot of other initiatives that occurred in the west, such as the efforts from the Western Interstate Energy Board, and the Public Utility EIM Group.

QUESTION: What's EIM again?

TODD KOCHHEISER: EIM, Energy Imbalance Market which – there's actually a slide on that, but we should have said that earlier. So, Energy Imbalance Market which is a bit of a misnomer, but that's what it's called.

The EIM, its priority, its major objective function is to serve load and imbalance at the lowest possible cost. So, that's Economic Dispatch. And it's going to try and do so while simultaneously ensuring that generation and transmission limitations are respected, so that's called Security Constrained. So ramp rates, or resources, min gen, thermal limits on transmission lines. So it's going to try to and find the optimal solution subject to all these constraints that results in the lowest possible cost to dispatch.

So usually the first bullet should make economists, PUC commissioners, GMs at utilities pretty excited. The second bullet, I think, makes operations engineers and dispatchers pretty excited and operators of resources. But if it was that simple we probably wouldn't need a slide deck that has 96 slides in it.

And so, it's going to use bid ranges, basically INC and DEC bid ranges from voluntarily offered participating resources to come up with the most economic, reliable, and secure solution of generation to meet that load and interchange demand. And generally speaking, there's no penalty for promptly communicating reliability actions or doing manual dispatches, although there are still some imbalance settlements that would apply.

So, what's included in the EIM? There's unit commitment for short-start resources. So some of those peaker units that you might be able to bring on quickly. Forward-looking congestion management. So, the market will respond to forced and as well as planned outages. We'll see later some of the information the market uses to run and some of that information that's required are outages, planned outages.

And that includes a 15-minute market, this is often abbreviated as FMM. Sometimes you'll see it as RTPD. FMM is 15-minute market, RTPD is real-time pre-dispatch. They're pretty much synonymous with one another. If you see on some further slides "RTPD," that's the 15-minute market. And it's not only running binding solution for the next 15-minute interval, but it's also looking out into the future four to seven FMM intervals, so almost up to two hours in the future, and sort of coming up with a plan for how to drive the 15-minute market subject to all these constraints.

And it includes a 5-minute dispatch that you'll see abbreviated often as RTD, real-time dispatch. And it also publishes advisory market awards out for 9-13 RTD intervals, so almost one hour out into the future, thereabouts.

There are some things that are not included in the EIM. Capacity Ancillary Services, so that's regulation, spin, non-spin, their contingency reserves. And it doesn't do Optimal Contingency Dispatch, so it's not going to deploy your contingency reserves. Of course, you can still manually dispatch your contingency reserves, that's a reliability action and the market allows that to occur.

This is the current map of the EIM Area –

HENRY TILLMAN: Sorry, so just a comment. Henry Tillman here. I think the – and I understand this, but I think it's important given this is EIM 101, I think we need to sort of make it clear for everybody. The EIM doesn't do a day-ahead dispatch. The balancing areas, the utilities, whoever has the load service obligation can basically set up whatever resources they want to serve their load any way they want. It's only the imbalances that are between the generation imbalance and load imbalances that are settled within EIM. I think you sort of glossed over that, but I think that's a really, really important element to this.

TODD KOCHHEISER: And there are a couple of slides later where I try to emphasize that point, but that's a good point, Henry, that you are still required to come into this market resource sufficient, meaning you have planned your operations for the hour in a way that's reliable and this isn't going to replace bilateral markets or the day-ahead processes that you're doing today. So, yeah, that's a good point.

It is a real-time, sub-hourly energy market that is going to try and find the least cost and most reliable way to serve load and imbalance in the EIM area, which this is the EIM area as it stands today. There's already a large number of existing EIM Entities, those are the Balancing Authorities that have signed up to be in the EIM. So, PacifiCorp, again, which operates to Balancing Authority Areas, PacifiCorp East and PacifiCorp West, those are in the EIM area, NV Energy, Arizona Public Services, Puget Sound Energy, Portland General Electric, Powerex, and Idaho Power.

There's a bunch of entities that are on the books. California's getting ready to integrate over the next several years. PNM recently announced their intent to join. Of course they're still pending their PUC approval.

So, kind of in summary, without an EIM each BA is essentially balancing load and resources within their own borders to serve their own load plus any interchange obligations, imports or exports. With an EIM, the market is going to dispatch resources across these participating Balancing Authorities or these EIM Entity BAAs to balance demand.

These are sort of some of the benefits. It can reduce cost by serving imbalance and load from the most economic resources, as I said before. It has the potential to enhance reliability by improving system visibility, which I think it does very well. And the responsiveness to planned and unplanned events, again, the benefit of one of wide area dispatch, a lot of the information that the market needs to operate, and results in a more efficient dispatch of resources within and between BAAs and leverages the geographic diversity of loads and resources across the market footprint and it does congestion management. So, it has a lot of neat features.

So, an EIM is an intra-hour, real-time energy market to serve load and imbalance across these Balancing Authorities. It's a tool for centralized five-minute dispatch of generators that have been voluntarily offered. An important characteristic of this market is that bidding is voluntary, so offering your resources, INC or DEC, is voluntary. It economically dispatches those offered resources and it does it in a security-constrained way.

To Henry's point earlier, or maybe a few more points that it is not. It's not an RTO. It doesn't have planning day-ahead markets. It's not BA consolidation. It's not a centralized unit commitment tool, except for those short start-resources. It's not a capacity market, and it's not a replacement for the current bi-lateral business structure There's probably a much longer list of things it is not, but hopefully you get the point.

So these things are generally not new. These sort of sub-hourly, five-minute, security-constrained, economic dispatch type of markets have been around for a long time in North America. There's a nice list of where you'll find a five-minute real-time market running that has many of the same characteristics of a EIM. They're also run in Europe, Australia – they're all over. So, these aren't necessarily a new thing.

FRED HEWITT: A question. Fred Hewitt, Northwest Energy Coalition. You may be covering this at some point. I'm pretty aware of how the dispatch works in the existing EIM, but how would dispatch work if Bonneville was in the EIM for Bonneville?

TODD KOCHHEISER: That's probably to be covered in much greater detail in a future stakeholder meeting.

STEVE KERNS: Yeah, if you recall the July 24th meeting where we identify those eight issues, that was definitely one of the eight and we'll be getting more deeper into that in either the October or the November meeting.

TODD KOCHHEISER: We're evaluating all the different participation models that different entities have employed, you know, from the Powerex model to more traditional models that –

FRED HEWITT: Yeah, that would actually be helpful. Thanks.

TODD KOCHHEISER: Yeah, but that's definitely a topic that we plan to cover in great detail. It's an important aspect of if or how we would participate. Yes, a question?

CAMERON YOURKOWSKI: Yeah. Cameron Yourkowski with Renewable Northwest. Just a high-level comment/request. On the slide about what the EIM is and what it isn't, I don't dispute any of those facts, but I do think it would be helpful maybe to put another column there about more of what does participation in the EIM or the underlying tools, implementing those tools on BPA's system, what other types of benefits or capabilities or options does just those basic new capabilities and tools provide BPA so that folks can start thinking about where else this could go other than just the strict EIM market definition and participation that we have today?

STEVE KERNS: Yeah, and I'd say hold us accountable for that throughout the entire process. This slide deck is meant to be as generic as possible to not get into Bonneville, but as part of going through our cost-benefit analysis and participation models over the next coming months, we want that to become clear. So, we think we will be handling that over time, but I appreciate it if you hold us accountable to that and make sure that ends up being the case.

TODD KOCHHEISER: Yeah, thanks, Cameron. This, today, what we're going over is really just trying to talk about how the EIM works today and try and level set and sort of set a baseline so that everybody can more fully participate in those future stakeholder meetings where we'd be getting into the provisioning of transmission, governance issues, dev issues, as well as how we plan to offer generation.

STEVE KERNS: Or transmission.

TODD KOCHHEISER: Or transmission. Well, transmission is one of the issues, yes. Without it, this thing doesn't work. So, transmission is a very important item.

So, any other questions kind of about this high-level description of what the EIM is? Again, we have additional slides. We're going to go into more details about kind of the nuts and bolts of how it works, but if there are any more questions from the room or on the phone I'll take those now or comments. No? Okay. Well, in that case I'm going to turn the microphone over to Russ Mantifel. He's going to go over the next couple of sections.

RUSS MANTIFEL: Okay. Can everybody hear me fine? Okay, so yeah, I'm Russ Mantifel. I'm with the business transformation office. I'll cover the sections on EIM governance and transmission. So, on slide 26 a high-level overview of the governing structure for the EIM.

Maybe I should actually start with what's not on the slide, which is that the EIM is at a high level governed under the auspices of the already existing CAISO governance structure with some specific mechanisms that were made for the purposes of governing the EIM.

The primary or the highest level one is the EIM Governing Body. This is comprised of five independent members, so the expectation or the rule, essentially, is that to be a member of the governing body, you don't represent an interest of a participant in the EIM.

That body has specific delegated authorities over EIM market rules that impact operations and economics. The selection is done through a nominating committee and it is confirmed by the ISO Board.

The Governing Body has a vote, and if you go to the CAISO stakeholder catalog, you can see designations for each of those issues about whether that issue is either a shared responsibility of both the EIM Governing Body and the ISO Board, solely under the rule of the ISO Board, or if it's an item that is specific to the EIM and is just under the authority of the EIM Governing Body. To the extent that the EIM Governing Body and the ISO Board disagree on any specific issue, there are rules, I believe, and so bylaws and other documents that interpret those rules to manage the reconciliation to the extent that there's a disagreement between the EIM Governing Body and the ISO Board. So, there is a level of independence from the ISO Board of the EIM Governing Body.

In addition to that, there's the EIM Body of State Regulators, which is an advisory committee that consists of regulatory commissions from the states of EIM Entities, which is the bulk of western states at this point in time, with the exception presently of New Mexico and Colorado, but that's all changing over time. So it's made of eight state officials, and it provides a state regulatory perspective under their responsibilities in terms of representing stakeholders and consumers in the states that are served by EIM Entities.

In addition to that, there is the Regional Issues Forum, which is more of a venue. It's a public vehicle for participants and interested stakeholders to discuss EIM-related issues, whether they be items that are potentially being discussed in an ISO stakeholder process, or if it is an issue that has been discovered or ongoing in terms of EIM operations or businesses. It's an opportunity for those parties, whether you're an actual EIM Entity, if you're a participant in the market, or if you're otherwise an interested stakeholder you participate in the Regional Issues Forum.

That body does not have any explicit voting rights necessarily, but is more a forum in which people can exchange ideas or raise issues. That's high level what it is. Are there questions?

ADAM SCHULTZ: Adam Schultz, the Oregon Department of Energy. I had a question about the Body of State Regulators. My understanding is those are PUC commissioners from those states now. And I know Seattle City Light is already a member, potentially Bonneville in the future. Is there any discussion about public power representation on that?

RUSS MANTIFEL: That is the current state and there has been discussion about that. I don't think that there are any explicit proposals for that. There is a review of the governance structure that is – that I think will be happening in the next year or so. Don, do you maybe want to talk about that?

DON FULLER: Yeah, I think to the question on public power representation, it has been raised. We're still considering it and working with the stakeholders, but don't have anything definitive on that yet. And there is a review of the overall governance structure that will be conducted by the governing body and I think that's slated for next year.

And, Russ, if I could, I wanted to add a clarification that also comes with an apology because I didn't catch this earlier. The third bullet under the Governing Body, the confirmation by the ISO Board of Governors occurred for the initial slate of the Governing Body members. Subsequent ones are confirmed solely by the governing body itself. So, in the recent case where Travis Kavulla was appointed to fill Doug Howe's position, that was a confirmation by the Governing Body. A fine line, but I wanted to clarify.

TODD KOCHHEISER: Yeah, great and we can make sure that it's updated, I think, in the slide deck. Thanks. And if you go back to the July 24th materials, and as you're looking forward the materials at Bonneville will have for our ongoing stakeholder process, governance is one of the eight primary issues. It is noted by Bonneville and our customers the representation of consumers and stakeholders that take service from IOUs that are regulated by public utility commissions or the like, but they're not being an analog necessarily at this point in time for consumers and stakeholders that take service from public utilities, whether they be somebody like Seattle Light, SRP, LADWP, or ultimately, Bonneville Power or our customers as well.

Any more questions on governance? We just have one slide on this. It's a deceptively complicated, but ostensibly simple issue. That's why we only have one slide.

RUSS MANTIFEL: Okay. All right, transmission. So, slide 28.

TODD KOCHHEISER: I'm in control of this.

RUSS MANTIFEL: Okay, so high level, as Todd said, transmission for all things is necessary to make things operate smoothly. The EIM is no exception. There are principles in the EIM, some of these are kind of bread and butter. Transmission is provided on a non-discriminatory manner consistent with Open Access principles. There are several different manners in which that is actually effective, right? And we'll get into some of those.

In addition, there's no explicit charge for transmission usage in the EIM. By that, we mean that when the market engine is running, as opposed to, for example, certain transactions inside and with the CAISO, there's no uplift charge or explicit cost in the economic dispatch to reflect the cost of transmission. Transmission is presumed to, essentially, already be paid for. There's no incremental cost when the market is optimizing. We'll get into some of the different manners in which that plays out in terms of the provision of transmission, which is there are two primary ways the transmission is provided in the EIM.

Being a 101 course, we're focusing on EIM transfers, and we'll get into what that is, but it's the net transfer between Balancing Authorities in addition to these more simple examples, each balancing authority may have different arrangements in terms of how it manages transmission internal to its system.

In terms of BA-to-BA transfers those are either provided directly by the transmission provider presently at no charge typically on what's called a zero NX or lowest NERC priority level transmission based on what is unused at the time. So, this is more prevalent in the Southwest in term of EIM Entities in which the EIM Entity, which is both the transmission provider and a Balancing Authority, looks at unscheduled transmission and on a somewhat real-time basis, makes that transmission available at no cost.

That's distinct from reserve transmission that is donated by merchants or holders of transmission from either that EIM Entity or a third-party transmission provider.

So, in this case, a market participant although it's not explicit I think – at present it is limited to market participants, who's already purchased transmission from a transmission provider, submits a tag that makes that transmission available for the purposes of an EIM transfer. Once that's made available, that transmission is treated the same way as any other EIM transfer in that it's essentially a public good. It's not reserved for that market participant; it's made available to the entire market for the most economic dispatch.

So in both cases, I think that there are different economic principles at play to justify there being no incremental charge for transmission in the market. In the case of the former, a transmission provider may already be receiving compensation for their transmission in some other manner, whether it's through rate basing or otherwise. In addition, there's also presumed to be some benefit for the transmission customers by virtue of their participating in the market. So, that kind of justifies that approach.

In terms of the reserve transmission donation, that's more explicit in that that transmission which is donated has been paid for by that customer. Thus far, it's been point-to-point, typically long-term firm point-to-point or redirect of long-term firm point-to-point. This happens on Bonneville system presently. There's a map later that shows where this is currently taking place. So in that case, that party's already committed to pay for that transmission throughout the year and so we, as the transmission provider, or a third-party transmission provider, is receiving direct compensation from a market participant, who then makes that transmission available. Questions on this slide before we get into the description of an EIM transfer?

PARTICIPANT: Question on the phone.

TODD KOCHHEISER: Go ahead.

RUSS MANTIFEL: Yeah, we'll go on the phone first. Go ahead.

(Break in audio.)

RUSS MANTIFEL: (Resumes in progress) – be made available for transmission, and then in addition to that, the CAISO Tariff, discusses the manner in which EIM transfers will be treated by the market. Yeah.

QUESTION: And as follow-ups on the third bullet, with the first sub-bullet when you talk about that unused, no-charge product that's a product that would then be defined in that tariff as well?

RUSS MANTIFEL: I believe that it is.

QUESTION: And are these FERC-approved tariffs?

RUSS MANTIFEL: All of them are presently is my understanding. Okay, and then do we have the question on the phone back?

STEVE LINCOLN: Yes. Sorry, something weird happened there. Can you hear me now, Russ?

RUSS MANTIFEL: Yeah, yeah, go ahead.

STEVE LINCOLN: Yeah, it's Steve Lincoln with TransAlta. You may have just discussed this, but the question was if we're going to cover in this forum or in a future forum how this is not a competing use of the transmission system, as in other Bonneville forums, we're talking a lot about how ATC is calculated and made available.

RUSS MANTIFEL: So, I would say that in terms of Bonneville substantively, we will be discussing that starting in either the October or the November meeting, in terms of discussing the manner in which Bonneville would provide transmission and the implications of doing that.

Strictly speaking, that is true especially on a traditional MOD29 path if you commit a firm tag which is – and we'll discuss this later – which is typically dynamic, that is considered ETC for the purposes of the ATC calculation, and is thus taken out of inventory that is – there is a bit of a distinction there to the extent that it is on a normal tag, because then you encumber based on the actual energy profile. That may create a distinction, but that may not actually be a significant difference.

That is potentially a question at issue and a reason why, for some people, it might recommend the zero NX method as opposed to the donation method. But I think that that will be more of a substantive conversation in future discussions.

STEVE LINCOLN: Perfect. Well, thanks very much. We're supportive of EIM, but just want to make sure that we're not running afoul of existing uses of the transmission system. So, thanks, we'll stay tuned.

RUSS MANTIFEL: Okay. Thanks, Steve. Other questions? Okay, so once again, the mechanism by which the EIM robots, the security-constrained economic dispatch engine optimizes is by utilizing EIM transfer schedules, which are typically, as I just said, scheduled on dynamic tags. And these are tag transactions, irrespective of the mechanism by which a transmission provider or an EIM Entity determines how it's going to make a transmission available. They are ultimately realized through an e-tag for the purposes of energy accounting, ACE calculation, ADC, et cetera.

Typically, those are done on dynamics. The exception of this, I believe there's one exception which is on the COI because there is an explicit limitation of the amount of dynamic scheduling available on the COI. So, in order to limit the extent to which that would prevent total dispatch between Northwest and Southwest Balancing Authorities or the Northwest and the CAISO ,we separate the five-minute dispatch on to a dynamic tag and the 15-minute – the FM RTPD dispatch is done on a static tag.

Otherwise, throughout the rest of the EIM all transfers are done on dynamic schedules. And the EIM transfer is – so it's the net energy between two Balancing Authorities. So, it's the algebraic quantity that's the result of the internal dispatch between and among multiple Balancing Authorities.

So when your individual resource gets dispatched or when your individual load is being served, it isn't necessarily deemed to be like a one-for-one, point-to-point transaction where generator A is serving load A or in this case generator B is serving load A. Each generator is settled and dispatched at itself, at its point of location electrically or physically, and then each load is settled at its location, and then each Balancing Authority also settles the net energy that's moving between and among multiple Balancing Authorities. And the net energy, whether it's positive or negative, an export or an import is then tagged as energy on the EIM transfer.

And so the one primary aspect that is necessary for an EIM provider to determine as they're going into the market is what sort of EIM transfers will be set up between and among one or more Balancing Authorities, the mechanism by which transmission is going to be made available and how that is going to be communicated and operated between multiple Balancing Authorities and that Balancing Authority and the market operator, the CAISO.

So, that's why this has been identified as one of the primary issues for our initial stakeholder process here, because it's one of the essential aspects of participation in the EIM in addition to, for example, how dispatch would actually work in the Balancing Authority, et cetera.

SYLVIA (PUGET): Question on the phone.

RUSS MANTIFEL: Yeah, go for it.

SYLVIA (PUGET): Hi, this is Sylvia from Puget. Can you go back to slide number 29? Okay. I just wanted confirmation or clarification that since the EIM transfer schedules, it primarily uses dynamic schedules that means that Bonneville will have to, as a transmission provider, decide to donate transmission to the market, it would be formed transmission and non-formed transmission. Go ahead.

RUSS MANTIFEL: So, yeah, okay. I see your question. I think that will be a question at issue for this initial stakeholder process and ultimately if Bonneville decides to join up until we would change our tariff and develop rates and terms and conditions for EIM participation.

At present, on Bonneville's system, dynamic schedules are only allowed on firm transmission. My expectation is that you know that.

SYLVIA (PUGET): Yes.

RUSS MANTIFEL: Okay. Yeah, that is a Bonneville policy that's not a NERC requirement or WECC or FERC requirement.

If, for example, if Bonneville were to go with a direct provision on something like zero NX, that policy would have to change and we would have to go through a process, a business practice change process, or whatever else to address that requirement.

But if Bonneville uses the existing mechanisms that are available, which is the donation of transmission under the current business practices, those would be on, absent any other changes that we would have to consider, those would be on firm transmission being that they would be dynamic.

SYLVIA (PUGET): Okay. My other question, actually this is sort of a statement because we have already had multiple conversations on this, is with regards to the COI how the DTC on the COI is limited to the north-south direction currently. I believe that as Bonneville decides on the cost effectiveness of joining the EIM it would be beneficial to see if the DTC calculation could be changed to include the south-to-north direction. It's just a statement.

RUSS MANTIFEL: Yeah, so for anyone in the room or on the phone or viewing this in the future, if you want some bedtime reading, our Dynamic Scheduling Practice sections I, H, and J discuss the manner in which that limited dynamic scheduling capability on the COI is allocated.

Bonneville and its peer facility owners on the COI – PAC and PGE – all utilize the same method for that allocation for each of their respective customers and you're right, that allocation one of the primary determinants of that allocation is north-to-south, long-term firm transmission rates and that is – Bonneville, I think, is not in a position to unilaterally make that change. I think, as

I've said previously direct with you, that's a question I think could possibly be taken up among all three facility owners on the COI to the extent there's a thought that that's detrimental.

SYLVIA (PUGET): My final question is what about the AC inter-tie DC or DC on any other system. Is that going to be considered, too, for the EIM transfer schedules? Is that just dynamic schedules?

RUSS MANTIFEL: Did you say the DC?

SYLVIA (PUGET): I'm sorry.

RUSS MANTIFEL: Did you say the DC?

SYLVIA (PUGET): Yes.

RUSS MANTIFEL: Okay. I think that is identified as one potential aspect of the grid mod suite of projects. So, we haven't committed to that. In addition, that's also another shared path that we operate with along with LADWP and it has multiple owners, but Bonneville is in the initial stages of looking at enabling 15-minute scheduling and potentially dynamic scheduling on the DC. Presently, only hourly schedules are allowed on the DC, whereas 15-minute and limited dynamic schedules are allowed on the AC.

So, we don't have a timeline for that. We're not in a position to make a commitment to do that as this point in time, but that is being considered as part of the grid mod.

SYLVIA (PUGET): All right, thank you.

RUSS MANTIFEL: That's your final question, Sylvia. Just kidding, you can ask more.

Okay, so more on ETSRs. So, EIM transfers utilize ETSRs, which are – all of these, once again, are abstractions of what is really going on in the market engine and the model in which there is an extremely sophisticated and already on Bonneville's system due to a significant amount of effort, very accurate model in terms of the physical impacts of the dispatch of individual resources for individual loads.

So, the actual market engine utilizes EIM transfers and ETSRs as constraints and modeling tools, but this is kind of an energy accounting abstraction of the primary function, which is to understand the physical limitations of the transmission system and to economically dispatch within those physical limitations, which uses a much more complicated model that Bonneville would benefit more from if it were part of the EIM, but we already do a significant amount of work under the CTA to ensure that they're accurately modeling our system. Is there a question on the phone, Katrina?

JOHN USELDINGER: This is John Useldinger from Portland General Electric.

RUSS MANTIFEL: You have the floor, Johnny, go.

JOHN USELDINGER: I just wanted to make sure – I'm sorry, going back to your previous point, is that anybody who has transmission rights on the COI north to south can request to use that dynamically. The EIM does not give you special authority to use your transmission rights dynamically. You can do that even if you're not in the EIM, and we do have customers who utilize transfer rights on the COI dynamically that aren't in the EIM.

RUSS MANTIFEL: Yeah, yeah. That's a correct clarification. The EIM transfers are just one of multiple potential uses of dynamic scheduling on the COI. There's a reg, up-reg down market in CAISO that utilizes dynamic scheduling. You can bid directly into the five-minute market. There are a myriad of other potential deals that one could execute with parties south of the COI that would utilize dynamic scheduling. And when that allocation takes place, there's no special treatment made for a dynamic schedule in the allocation of scheduling rights because it's for the EIM or otherwise.

JOHN USELDINGER: I just wanted to make sure, I think that's a misnomer. A lot of folks that we talk to have said, "Well, does the EIM have priority to use their transmission dynamically?" No, that's not the case. The allocator works the way the allocator works, and you're not given any special bonus DTC because you are a participant in the EIM.

RUSS MANTIFEL: True. Yeah, and once again, Johnny from PGE, Portal General, PacifiCorp, and BPA in 2014 agreed on a common set of business practices and allocation methods for dynamic scheduling on the COI.

So, what Johnny said is true for all three facility owners on the COI. We have, essentially – we mirror each other in business practice language, and Bonneville executes on allocation methodology as the path operator equally for all three facility owners of the COI.

And then Sylvia asked the question from Puget, we haven't yet had a move forward with enabling dynamic scheduling for capacity owners that are also transmission providers, but that's possible.

And then I'm getting this is – as always is the case with the dynamic scheduling on the COI, it turns into a time sink. I'm getting a motion to move on to the next topic.

PARTICIPANT: I think we have a question from e-mail, if you want to go ahead and –

PARTICIPANT: What is the level of granularity for the setting out of energy exchanges? Is this at the BPA level? Is there one market clearing price or does the EIM robot calculate those prices for each node zone AA?

RUSS MANTIFEL: Multiple of those things are true. So, the EIM transfer –

PARTICIPANT: (Inaudible, off mic.)

RUSS MANTIFEL: Oh, okay, yeah, in case you didn't hear. So, what's the level of granularity for the calculation of the EIM transfer? And some possibilities that were listed were individual nodal prices or I think BPA-specific or BA area prices or system-wide prices.

So I think multiple of those things can be true. The actual EIM transfer is the net schedule, it's the product of the dispatches between – from one Balancing Authority to another Balancing Authority.

Prices are calculated nodally at each generator and for each load. Presently, each Balancing Authority has opted to have one load price for its entire Balancing Authority, but there's one load price for each EIM Balancing Authority that are calculated separately, while each participating generator has its own locational marginal price calculated at its location, which is – Todd will go into the calculation of the locational marginal price later.

And so, those can be the same to the extent that there is not congestion on ETSRs or otherwise, those prices would level out with the exception of possibly losses. And for load, you get one load aggregation point price for each Balancing Authority. I think EIM transfers can cause price separation, but the prices are actually calculated at the loads and resources.

So, the manner in which the EIM transfers work is through the use of the ETSR, which is modeled as a system resource. So, once again, it's actually dispatching individual resource and calculating prices, but the EIM creates an abstraction of that for the purposes of the interchange through that's what's called the ETSR. This is analogous to a source and sink, so that anchors for the purposes of energy accounting what the source Balancing Authority is. It's modeled as a system resource and what distinct Balancing Authority is, which is also modeled as a system resource.

You can act as a source or a sink depending on whether you are importing or exporting. You can also just be a net wheeler. You can be, in aggregate, neither a source nor a sink if you're just facilitating transfers through your system.

So, yeah, it's an aggregated abstraction of the generation inside that Balancing Authority. The ETSR and the EIM transfer is not tied to any specific resource or any load. So, if you look at an EIM transfer, you're not going to necessarily know which generators are getting paid for that transfer.

There are other mechanisms that kind of back into that, but there's no explicit, linear relationship between those things. And, once again, they are an export or an import. Prices are calculated separately as an abstraction for the purposes of energy accounting, making sure ACE is calculated correctly and operations of the Balancing Authority don't get gunked up.

PARTICIPANT: So, real quick. Sorry. So, before you move off of that. Is there an explicit tie, going back to the last stakeholder meeting, there was a potential aggregation of resources, Chief Joe, Coulee Complex, Lower Snake Complex, Lower Columbia Complex, which is an aggregation of resources. Would those be considered the ETSRs, that aggregation?

RUSS MANTIFEL: No. I think you should think of those separately, which is that we would determine the manner in which we would model the FCRPS in terms of is it treated as one generator, three generators, ten generators? But the EIM transfer is always going to be an aggregate of that and any other participating generators in our system. So, it's always going to be an aggregation of all the participating resource. And so I think you have to treat those separately in your mind, because if there's an IPP that's bidding, that would also comprise the EIM transfer or ETSR.

Any other questions before we move on to what these look like now?

So, Balancing Authorities are in the bubbles. So, we have a screen with bubbles and lines on it, which represent the existing EIM transfers today. And so it's tough to see this on the projection here, but Bonneville is currently a provider of transmission for EIM and transfers, even though we are not an EIM Entity. And you can see this – do we have a pointer on here?

PARTICIPANT: There's a pointer right there.

RUSS MANTIFEL: Yeah, okay. So, Puget has an EIM transfer to PacWest, which is scheduled on BPA internal network transmission, and that is done under the customer donation framework. Puget owns a firm point-to-point contract, pays for that transmission, and then submits a tag to make that transmission available for an EIM transfer between its Balancing Authority and PacWest.

PGE, on its delivery to the CAISO has one leg of that transfer, which is on internal Bonneville transmission to get to, I believe, the head of the inter-tie, at which point they are then tacking on their own transmission.

The complication of that is that on the COI, Bonneville is the path operator for all transmission, even if we're not the transmission service provider. In addition, on the COI, Powerex, BC Hydro uses Bonneville COI transmission to deliver directly from Powerex to CAISO and vice versa. That is on Bonneville transmission both on, I believe, the network and on the COI, that's separate from the existing transfer they have directly with Puget, which is not utilizing transmission purchased from Bonneville, but which is operated on the southern end of the Northern Inter-Tie by Bonneville. That's separate from these EIM transfers that are done outside of Bonneville's system.

There's another bubble – do we not have Idaho on this one? Sorry, I was imagining it here. So, for all of these, Bonneville is in no way a party to those transactions. Through the CTA, we get a significant amount of data on that.

For the bulk, if not all of these other transfers, these are done on a zero NX tag that's made available directly by the transmission provider. My understanding is that at times, if not always, PGE's direct connection with PAC is done on as-available transmission, directly provided by the transmission provider.

The customer donation is kind of an artifact of the use of Bonneville transmission or transmission that Bonneville operates to account for there being multiple users of the system.

I'm going to stop. This is your last chance to ask me questions. Any questions on transmission? Once again, a lot of this will be discussed over time, both in the initial stakeholder process we'll be doing in the next couple months. But if Bonneville, ultimately, joins, it will continue to be a discussion as we develop rates, terms and services, and tariff conditions as well. So, this is kind of a general description of how the market views transmission.

TODD KOCHHEISER: This is Todd. It's probably worth noting that some of those transfers are shown as single things, single ETSRs, but really it could be multiple ETSRs and multiple tags comprising any one of those transfers between any of those two EIM Entity balancing authorities.

And these ETSRs and these transfers that have tags backing them are another one of the constraints that the market takes into consideration when it's running its optimization. So if transmission isn't made available or isn't available for some reason, then that would potentially constrain the optimal market solution.

Okay, we just have a few more slides. This is acronym and word soup time, a bunch of definitions that, hopefully, will set us up for our after-break topic. Let's just get going through it.

We already talked about the EIM. This is just the roles and definitions section. Again, it's the operation of the ISO's real-time market. The market operator, we've already discussed, is the CAISO.

We've talked about EIM Entities already. It's a Balancing Authority that represents one or more transmission service providers that make transmission available for the EIM. It enters into a pro-forma implementation agreement to enable the EIM and its BAA or BAAs, plural, in the case of PacifiCorp. So, if Bonneville were to join the Energy Imbalance Market, we would join as an EIM Entity, and that would be the transmission side of our business joining in our Balancing Authority.

We would also establish or an EIM Entity establishes the resource and the transmission service requirements for eligibility to participate in the EIM, so as a participating resource, for example. And by enabling the EIM, real-time load and generation imbalance within the EIM BAA will be settled through the Energy Imbalance Market, those are kind of the basic characteristics of an EIM Entity.

EIM participating resource, you'll often see this in various documentation as well as future slides as written as an EIMPR, EIM Participating Resource. This is going to be a resource that is located within an EIM Entity's BAA and that elects to participate in the EIM. So, part of that eligibility would be determined by the EIM Entity. They would enter into a pro-forma EIM participating resource agreement with the California ISO, and they would receive 15-minute market schedules and five-minute market dispatches.

Contrasted with an EIM non-participating resource. This is all the other resources in the EIM Entity's Balancing Authority area that have chosen not to participate. And in the market, they submit – or at least the EIM Entity submits hourly resource and import/export schedules.

The EIM Entity Scheduling Coordinator. This is, typically, the EIM Entity itself that provides this role, or they could have a designated third party. They're going to be certified by the ISO as being – as a scheduling coordinator, and they'd enter into a pro-forma EIM Entity scheduling coordinator agreement. And some of the responsibility they have is approving resource plans for the EIM Entity Balancing Authority area, sort of talks about that workflow and process a little bit later. They would be submitting settlement-quality meter data to the market, and they would – also uninstructed imbalance energy settlements of resources not participating in the EIM. So, essentially, they would be settling with the non-participating resources and they would be distributing costs or revenue from uplift allocations to the EIM BAA, so it's got a role in the front end of making sure there's a lot of data and resource plans that are submitted to the market so it runs effectively, and it has a role on the back end to provide settlement quality meter data, as well as handle settlements between – settlements with non-participating resources and also various uplifts and charges that would get distributed to transmission customers.

An EIM Participating Resource Scheduling Coordinator is essentially the role there is they also have to be certified ISO and enter into a pro-forma EIM Participating Resource Scheduling Agreement, but their job is to submit resource plans for the participating resources, the ones that are actually – resources that are going to be offered to the market. And they're going to receive dispatch instructions and market awards, and they're going to do settlement directly with the market operator, the California ISO.

So, contrasted with a non-participating resource, those settlements happen between the California ISO, the market operator, and the EIM Entity, whereas if you're a participating resource, you're going to be settling directly with the California ISO.

EIM Transmission Service Provider is really just an entity that's making transmission available to the market and kind of controls that transmission, at least from the market's perspective, and informs the market and the EIM Entity of the transmission they're making available. So, I won't go into that again.

Finally, base schedules. Base schedules in the EIM are currently forward hourly quantities. And it's generally these are the reference for measuring imbalance deviations for settlement purposes, and includes generation and interchange schedules and load forecast.

And then a Resource Plan. These are the base schedules, energy bids, and ancillary service schedules that these scheduling coordinators are submitting to the market.

There's also a Base Schedule Coordinator. It's probably worth saying that a lot of these roles are performed by the same entity or same organization, but there are distinctions.

The Base Schedule Coordinator is a participating or non-participating resource that submits base schedules and ancillary service schedules.

EIM Entity Base Schedule Coordinator, which is typically the EIM Entity scheduling coordinator, is responsible for submitting any base schedules, ancillary service schedules for non-participating resources, and any changes after T-55. And we'll have some slides later that show the market timing and when one entity is submitting schedule-based schedules versus when another does that.

Any questions on the word soup?

QUESTION: Yes. I'm going to ask this now instead of after the break, because it may have repercussions to timelines and resource sufficiency requirements and all that.

So, when you look at the different models that Bonneville's looking at, are you looking at models where Bonneville as an EIM Entity would only do a resource – would only be as a participating resource for specific resources or group of resources?

PARTICIPANT: Could you please repeat the question again?

QUESTION: Okay, bear with me, it's a long question, so your break is going to be worth it.

So, when you look at the different models that Bonneville is exploring, I just want to map this out real quick. As an EIM Entity, would they be looking at, for example, a model where they're just as participating resources, for example the three groups of resources that were identified in the stakeholder process, and that all the base schedules would be associated with just those resources.

So, for example, you're not looking to take imbalanced service for the entire Balancing Authority from the EIM, you're only going to restrict it to these specific resources. That could be one model, whereas another model could be that plus settlement of all your imbalance for the balancing authority. Is that fair to say?

FRANK PULYEART: Yes, I think I understand what you're asking.

QUESTION: The reason I say it is because after the break, you've got different timelines associated with what you have to submit as just for resources versus what has to be submitted for your entire load and resource balance as a Balancing Authority area, and it also impacts your resource efficiency requirements.

TODD KOCHHEISER: Correct, yeah. Well, I would say, generally speaking, what we are evaluating is participating in sort of a pro-forma manner. So that's our current – what we're evaluating and when we're looking at cost benefit, that sort of stuff, it's as a traditional, pro-forma EIM Entity where all of the loads and all of the generation in our Balancing Authority would be part of the market.

I don't know if you want to expand on that at all, Russ?

RUSS MANTIFEL: Yes. I do want to clarify, if I understand your question correctly, in order to accommodate that, you essentially have to create a pseudo Balancing Authority within the Balancing Authority. We were not interested in pursuing that option. The complexity and the reduced benefits from only optimizing a subset of resources was not sustainable in terms of a cost-benefit analysis for Bonneville.

So, I think we understand that there are maybe some Balancing Authorities that potentially would operate in a similar manner, maybe bank with WAPA, they essentially already operate independently prior to EIM operation as separate Balancing Authorities. Even though the register as one, they ultimately roll up to one ACE. The complexity of implementing that would be astronomical for Bonneville and for that reason, as Todd said, we're really looking at the way – the standard mechanism of owning, which is your Balancing Authority joins. And there are, certainly, implications for everybody in the Balancing Authority, irrespective of whether or not your participating resource or remote loads already deal with this in multiple Balancing Authorities.

TODD KOCHHEISER: The equivalent to creating an embedded Balancing Authority.

QUESTION: So, just to make sure I understand it. Under that model, the pro-forma model, you would then be identifying specifically your participating resources, but then you would actually identify your non-participating resources.

TODD KOCHHEISER: Correct, yes.

QUESTION: And then you would also submit your entire Balancing Authority area, essentially load and resource balanced, associated with both your participating and non-participating, going into the hour – and we'll get to it, your resource efficiency task, but also you have to follow those three timelines, right?

TODD KOCHHEISER: Yes, that's correct. That's the contemplating we're doing.

PARTICIPANT: So, Ed, we didn't really think about that too much. Are you coming at it from a different angle?

QUESTION: No, I mean, we're thinking about it because if it applies to your entire Balancing Authority area, as opposed to just putting in specific resources, it's going to have impacts on basically all of your BPA products, both transmission and power. Right?

TODD KOCHHEISER: Yes.

QUESTION: Your energy imbalance products, you know, how you do persistent deviation, your slice product, maybe the only product it doesn't impact is your block.

RUSS MANTIFEL: This is an exciting opportunity. (Laughter.) Yes. And we did, to clarify, we did think about those impacts. Like I said, the only mechanism of joining in a way that avoids that is not feasible from Bonneville's perspective. We expect to have a significant conversation over time about what those impacts are, the right way to manage those, and what they are, separately, for different types of customers. That will take a long time to really be articulated for everybody, as has been the case for other EIM Entities that have joined.

Given that, we have a lot of experience in terms of the impacts of customers in Balancing Authority areas because we have transfer load or remote load in multiple Balancing Authority areas that are in the EIM market. We have an understanding of what the requirements are for those customers, even if you're not participating in the market, even if you're not bidding generation in. And with that understanding, we're still at the point where we think that moving forward provides significant benefits, which is the purpose of the ongoing stakeholder process.

QUESTION: And just to make sure I heard it right, you think that you get more benefit through sort of the all-in approach as opposed to maybe just doing it with specific resources? I could see where if it was just specific resources, you could minimize some of those impacts with some of your other products.

RUSS MANTIFEL: Yes. And then you also minimize some of the benefits if you're not actually optimizing for all of the load, then you also have to de-optimize your reserves, because then you have to settle that imbalance separately so you're both minimizing the amount of load that's being served, and then you're also minimizing the amount of generation that's made available and you're increasing your reserve requirement because you have to meet the CAISO test, and the you need to do whatever planning you need to do to meet your BAL-1/BAL-2 requirements for the other Balancing Authority that's inside the BA. So, yes, it really starts to eat at both ends of the cost benefit.

TODD KOCHHEISER: And keep in mind, there are other resources in our BA other than just the federal hydro resources. They may want to participate as well.

STEVE KERNS: Okay, I'll take one more question, and then we'll have a break.

QUESTION: So, you said the base schedule is currently a forward hourly energy schedule. I'm curious about the word "currently," does that sort of anticipate that with the enhanced market and potential extension of that to the EIM participants, that could become a 15-minute rather than hourly energy schedule?

TODD KOCHHEISER: That could happen. That could occur. Today, it's hour. In the future, it could be 15 minutes.

RUSS MANTIFEL: And I think even, strictly speaking, that's at issue on the day-ahead market, not the day-ahead market expansion, but the enhance day-ahead market on the inter-tie. That's profiles, 15-minute base schedules could be the case just for the CAISO, but anything is possible.

QUESTION: I am still trying to sort all of that out. And I understand at the time moment they're saying, in effect, 15 minutes, but an hourly submission is optional.

RUSS MANTIFEL: Yeah. But you might be giving us a little too much credit in terms of our thinking behind the work, currently.

QUESTION: We're all wrestling with the EIM stuff. Yeah.

STEVE KERNS: Let's take a break. Ten minutes sounds good, we'll come back at 10:35. Thank you.

(Pause for break.)

STEVE KERNS: Okay, we're going to get started now. We're going to go back to Todd Kochheiser, and he is going to talk about market activities.

TODD KOCHHEISER: All right. Hopefully, this won't take too long and you'll have lots of time to hear all about resource sufficiency, it's a very fascinating topic.

So, market activities. This is compiling the hourly resource plan. So, this is what's going to happen before the operating hour. We'll talk about the exact timelines of when these things happen in some future slides. But before the operating hour, there's going to be compiling demand forecast, variable energy forecast, transmission outages, generation outages, and various transmission limits as well as base schedules for participating resources, bid ranges for those participating resources, non-participating resource base schedules, and hourly interchange schedules. So, that's kind of an inventory of the major categories of data that the market's going to need to operate during the hour.

Prior to the hour, there's going to be a resource sufficiency evaluation. And this is what Frank's going to talk about here in a few minutes. And what's going to happen at several times, there's three evaluations of resource efficiency, the first one is a T-75, the results are published, hourly base schedules can be adjusted, and then again at T-55, there will be another resource sufficiency evaluation. And then, finally, at T-40, there's a final resource sufficiency evaluation that basically results in the final hourly resource plan that the market is going to use.

We're definitely going to go into lots of detail about those resource sufficiency evaluations. Then, along comes the 15-minute market, and in addition to all those demand forecasts, newer, more contemporary demand forecasts, variable energy forecasts, transmission outages, generation outages, and transmission limits. The market is going to take the best information it has at the time the 15-minute market runs, including economic bids, and that's going to result in some 15-minute schedules as well as unit commitments for short-start resources. So, that's what's going to come out of the 15-minute market, and it's going to happen four times during the hour.

Then the five-minute market comes along. And it has even better demand forecast data, better for forecast, better transmission outage information, better generation outage information, more contemporary transmission limits. As economic bids, again, and it has a state estimator solution. The state estimator is a real-time tool that we use over in Transmission Operations that essentially can provide a current network model, a state estimation of the entire Western Interconnection Grid, and that gets fed into the market as well, and out comes a bunch of dispatch instructions, five-minute dispatch instructions.

Then along comes settlements. A very complex process, but a very important one. And the way the settlements generally work is the reference is the hourly base schedules, and then there's the 15-minute schedule that came out of the market, so your 15-minute market award, as well as your five-minute dispatch. And this is sort of a participating resource sort of look at things, and a final meter read. So, some settlement quality meter data. And the settlement process is going to produce settlement statement for participating resources. That settlement statement is going to go to the scheduling coordinator for the EIM participating resources. There's going to be a settlement statement for all the EIM non-participating resources, that's going to go to the EIM Entity scheduling coordinator, so that's going to basically go to the BA. And the EIM Entity scheduling coordinator settlement statement for all the various neutrality accounts, those are going to go to the EIM scheduling coordinator as well. There would be, then, a subsequent process thought the EIM Entity would use to essentially allocate those various credits and debits and charges.

HUMAIRA FALKENBERG: Question from the phone. Humaira Falkenberg from Pacific. Could you please explain why there would be a need for an EIM non-participating resource settlement statement? If it's a non-participating resource –

TODD KOCHHEISER: Yeah. Maybe it should be better stated as the EIM Entity scheduling coordinator is going to receive, as part of its settlements, imbalance credits and debits for those non-participating resources, the difference between their hourly base schedules and any deviation between that and the final meter read.

HUMAIRA FALKENBERG: Thank you.

TODD KOCHHEISER: Yeah. The EIM non-participating resources do not have a direct relationship with the California ISO. So, those settlements for any imbalance, the difference between the hourly base schedule and the final meter read are going to happen as part of the EIM Entity's settlement statement.

So, participating resources will settle directly with the California ISO. As a non-participating resource or transmission customer of an EIM Entity, you will end up setting credits and debits on your transmission bill from the EIM Entity. There's a question on WebEx.

QUESTION: (Inaudible, off mic.)

TODD KOCHHEISER: Okay. Generally – I'm going to say "generally speaking," which is me caveating it's complex and there's probably some optionality here. But, generally speaking, the data that the market is using when it runs, and it is a reference for settlement purposes from the CAISO to the EIM Entity or the EIM participating resource is going to be based on the information the market had at T-40. Okay?

Now, many – maybe even all – of the current EIM Entities have different timelines that they require data to be submitted by. So, T-57 is a very common timeline for a lot of the EIM Entities for submitting e-tags and base schedules for non-participating resources. And then if they don't change between T-57 and T-40, then effectively, the T-57 value ends up being the reference for settlement purposes.

There is another slide on that, but it's a good question. Any other questions?

All right. Let's move on, then, if there are no more questions about those basic, high-level processes.

Base schedules, bids, and timing. So, base schedules, basically, generation and interchange must equal load. So at T-75, 55, and 40 minutes ahead of each hour, there's an opportunity to submit new base schedules to try and essentially make a balanced solution for the purposes of the market running and passing hourly resource sufficiency tests. Which, again, we're going to get into a lot of detail in a few minutes about base schedules and their interaction with these resource sufficiency tests.

This is, I don't know, conceptually kind of how I think about it as far as the difference between a participating and a non-participating resource and the type of information that's being submitted as part of the resource plan for those different types of resources. If you're a non-participating resource, the type of information the market's going to need is a base schedule, so this is that line in the middle, like 300 megawatts, and if that resource happens to be carrying any ancillary services – reg, contingency, et cetera – those can also be submitted as part of the resource plan, as well as an operational Pmax and operational Pmin, those are the types of information that would be submitted for a non-participating resource typically by the EIM Entity base scheduling coordinator.

As a participating resource on the left, it sort of changes a little bit where you might have the same base schedule, 300 megawatts, but you've also provided the market with an economic bid range from the amount of capacity up and down that is available to the market to be dispatched economically. Otherwise, that's a lot of the same information.

The one little note that's important is that currently bids have to be submitted by T-75 and so essentially they're locked a T-75 for the operating hour beginning at T, so they're essentially locked for 135 minutes.

Here's just an example of a bid range. On the vertical axis is the price per megawatt hour that you're offering the resource, and then across the horizontal axis is the megawatts that you're offering.

As a point of interest, I think currently you can have ten segments in your bid offer. They need to be monotonically increasing. If you happen to have a multi-stage generator, multiple configurations, you can submit separate bids for each configuration and those prices for those bids could overlap as well.

QUESTION: Real quick question.

TODD KOCHHEISER: Yes?

QUESTION: So, when you say the bids are locked, is the entirety of the bid both in terms of the range and the price? Or are there certain components that can still change?

TODD KOCHHEISER: Well, it's the range and the price. One of the ways that you can adjust your bid range later is by submitting outages or D rates on your units. So, if something did occur later that required you to reduce the capacity of your resource, you could submit an outage card, and that might end up capping some of maybe your incremental bid range, or your min gen could change, maybe have a higher min gen because of ambient temperature or something like that.

So, that's one way you could end up effectively having some adjustments made after that interest-75 bid range. Another way is that your base schedule, itself, can be adjusted up to T-55. As a participant, of course, you can do that. Within your bid range, you can move the midpoint up or down. So, you can also affect your effective incremental capacity that's available in the market compared to your decremental capacity.

Those are a couple tools that participating resources can use to manage their bid range. I hope that answered the question, but effectively, the bid range that's submitted is what's used for the hour, but then there are some other ways you can adjust it up or down a little bit. I've never bid a generator, but this is what I've heard. (Laughter.) There are probably some people on the phone or in the room that have –

QUESTION: I mean, I guess specific for hydro, because that's what you're going to be bidding, I mean, it would be a specific operation that restricts your ramping or something like that that comes in after the fact. Could that be considered a manual dispatch sort of impingement that you can say, hey, this was my bid, but because of a hydro operation, not necessarily loss of a unit?

TODD KOCHHEISER: Yeah. Well, I think one of the – you're always – you have not given up control of your resource. It's still your resource and you can still do a manual dispatch, and you will still be doing manual dispatches. Ramp rates is another thing that might change as well. And you can notify the market operator of a ramp rate change, that could effectively limit how far, how quickly you can move as well.

But it is a voluntary market. The market will recognize that you didn't move your resource or that you didn't move your resource or that you manually moved your resource as well as the markets were running. So, you don't give up control I think is really important.

RUSS MANTIFEL: And one of the things that we've identified internally is what's the right way to manage late-breaking constraints. You know, outage cards aren't explicitly for a proper unit outage necessarily. You can submit outage cards for a wide range of reasons, not just you lost the unit or something like that, so that's one potential possibility, yes.

And the impact of that is always financial, right? So you could potentially get a dispatch operating target that's no longer feasible for you because of maybe some sort of late-breaking constraint that came in after your bid. If you don't dispatch to it, it's your discretion to dispatch to it. If you don't, you're going to get settled out at a different price. It's going to be a financial impact. But we are looking at what's the right way to integrate late-breaking constraints into our bidding strategy to mitigate the financial risk. But the risk is always financial.

TODD KOCHHEISER: It's always financial.

RUSS MANTIFEL: You operate your resources, they don't control anything to where you don't want them to be.

TODD KOCHHEISER: And I probably should have mentioned this before. At the end of the day, it's still your Balancing Authority. You're still responsible for all the various reliability standards, the CAISOs not responsible for those, you are. So, you're still operating your Balancing Authority, you're still managing your ACE, and you still need to be able to do things you need to do to operate reliably. And some of those things might be in conflict to market dispatch, and you try and mitigate them as best you can from the settlements perspective.

RUSS MANTIFEL: Yes. Sometimes I describe it as really what the market is doing is every five minutes, and for future intervals, it's going to come up with the best plan. Right? That's all it does. It tells you, through myriad technological processes and interactions, this is the best plan, given this information, to run your balancing authority. And then it behooves you 99 times out of 100 or 99.9 percent of the time to follow that plan, but if you're unable to or unwilling to, it's going to come up with another plan that reflects the fact that you didn't follow the last plan. Right? And you're going to see financial consequences as a result of that. But it really just comes up with every five minutes, crunching a bunch of numbers. Based on this robot, this is the best plan to serve your load and optimize your resources.

TODD KOCHHEISER: Subject to all the various constraints that it's aware of. The quality of the data that goes into the model and into the optimization is really important to get the best possible results out of it as well. Any other questions on that one? Move on to base schedule timing, which is hard to see. I'm sorry, but what this is showing, up in the upper-right-hand corner, it says XX00, so you can just consider this to be the beginning of an hour T reference. Backing all the way up here to what's labeled as XX45, that is 75 minutes prior to the operating hour beginning at zero.

And so over here, we have bid deadlines and the first base schedule submissions at T-75. And, again, the bids are going to be locked at that point, effectively, for that operating hour beginning at time T, or XX00.

Then there's another opportunity for participating resources to adjust their base schedules. There's another deadline at T-55 that coincides with another resource efficiency evaluation. Between T-55 and T-40, there's an opportunity for any other base schedule adjustments to be made by the EIM Entity. Typically, at T-55, that's where a participating resource, that's your last chance to adjust your base schedule, but the EIM Entities can continue to adjust base schedules at T-40. Again, likely trying to resolve any feasibility or resource efficiency issues between T-55 and T-40.

What happens here at T-37.5 minutes is an RTTD snapshot, or basically an RTPD market run. RTPD, again, being real-time, pre-dispatch. That's the 15-minute market.

So, for the first 15-minute interval beginning at T, the market's going to take the best information it has at T-37.5 and come up with a solution for that first 15-minute interval. And it will publish those results here about T-22.5, that's giving a couple minutes to comply with any scheduling deadlines, typically 20 minutes prior to each 15-minute interval is the deadline for any tagging.

And then along comes the real-time market, and the real-time market runs 7.5 minutes prior to the beginning of each five-minute interval. So, it takes a snapshot at T-7.5, it runs its solution, that usually takes two or three minutes, publishes that solution, and then the resources begin ramping from 2.5 minutes before the interval to the center of the interval, so 2.5 before to 2.5 after. And we have a very detailed slide on that in just one minute, so we'll show you kind of this all put together.

Here's another kind of picture about base schedule timing. This is a different way to look at it. On to the top here, you have the market participants. On the bottom, you have the market operators. So, again, at T-75, you have the base schedule that energy bids are due by resources, T-55 – excuse me, down here at T-60, there's the publishing of the resource efficiency results, and then back up here T-55, we can update – resources can update their base schedules again, then again at T-45, the results of the second sufficiency test are published. And then at T-40, this is the last chance for the EIM Entity scheduling coordinator to adjust base schedules, and then there's a final resource sufficiency evaluation that happens after that at, again, T-37.5 for the 15-minute market and publishing of the market awards and the tagging deadline of T-20.

This is what one five-minute RTD run kind of looks like. You have essentially, again, like I said before, for the interval XX00 to XX05, so that first five-minute interval of this hour, the market took the best information it had at T-7.5 minutes and the market engine runs. And, again, at some point within one or two minutes of the beginning of the ramp, it publishes the results. Those results are communicated to all the participating resources through a system called ADS – Automatic Dispatch System. The resources ramp to the middle of that 00 to 05 solution, so the market is essentially solving for the middle of each five-minute interval.

Now, if you put them all together, you get this sort of picture. You've got the first interval one running at 7.5 before it's ramping. While interval one is being ramped, the market is solving for interval two. While interval two is being ramped, you know, it's solving for interval three ramp. So they get all sort of stair-stepped together.

If you want to kind of put it all together, you sort of get this sort of look how things kind of work together. So, during an hour, you're busy planning for the next hour, while the hour you're in, the five-minute mark is just running along, providing solutions. So, there's kind of a planning phase for the hour, then there's an operational phase for the hour.

I didn't draw the 15-minute market on top of here, if there's a 15-minute timing that kind of looks similar, but has 15-minute blocks. And for the most part, it's typically not a physical solution.

The 15-minute mark is more of a financial solution. It's the five-minute market that results in a physical dispatch.

JIM FARRAR: Todd, could I ask a question on that graph?

TODD KOCHHEISER: Yes.

JIM FARRAR: This is Jim Farrar.

TODD KOCHHEISER: Hi, Jim.

JIM FARRAR: How are you doing? The box is square, so it kind of assumes you're going to hit that – it looks like you're going to hit the megawatt right at the beginning of the five minutes and hold it till the end of the five minutes. So, to the extent you're ramping up to get to the middle, is there an imbalance between the schedule and the generator? I don't know if I asked that question well.

So, if a generator was expected to be at 100 megawatts midway during that five-minute period and it was starting at 50, it might not get all the way there by the beginning of that period. So, does that create an imbalance, which is then going to be charged to the generator?

TODD KOCHHEISER: Well, through the middle of settlement-quality meter data, which would be an integrated energy amount, a five-minute interval would be the difference, then, between the integrated meter read and the five-minute award for that interval.

So, I don't know if that answers your question or not, but the ADS system actually does calculate a ramp for you, so you'll be getting a ramp driving you to that midpoint. So, this is a plan. This is what the market is expecting you to do at the end of the day, at the end of whatever settlement quality meter data is due. It's the difference between that integrated energy for that five-minute interval and your five-minute market dispatch.

JIM FARRAR: Okay, that's great. Thank you.

TODD KOCHHEISER: Obviously, there are going to be overs and unders, and hopefully it all works out over time, right? There's another question in the room?

QUESTION: (Inaudible, off mic.)

(Break for direction.)

ROBERT FORD: Robert Ford, Corps of Engineers, Portland District. I'm a generator guy, again. So, I'm seeing an inconsistency. So, in your model there for let's call it interval seven, you're going to do your RTD run, you're going to do your determination, you're going to do a ramp-up, but during the ramp-up for seven, you're still supplying power in interval six. Right?

TODD KOCHHEISER: Yes.

ROBERT FORD: So, I guess my question is: Let's say that the interval-seven data requirement is larger than the interval-six requirement, so now you've got generators that are either holding for interval six or ramping for interval seven at the same time.

TODD KOCHHEISER: These would typically be, I think in most cases, these are net plant dispatches. I maybe should have said earlier you could bid an individual unit if you wanted. Some people probably do. In the case of us, Bonneville, it would likely be the entire resource, so the entire plant, so Grand Coulee, Chief. And so what this really ends up looking like is a continuous ramp, a smooth ramp that you would be seeing as it transitions from interval to interval to interval to interval.

ROBERT FORD: So, it could potentially mean more movement by the unit over time?

TODD KOCHHEISER: It could. It could. And one of the things that probably the scenario where that's most likely to happen, and maybe I'll look to Don or other people in the room, but if your resource happens to be a marginal resource, that is the price you're at is marginal, in which case you might see more movement in that particular case. Otherwise, you know, in a lot of cases, I think you're likely to be dispatched closer to the top of your bid range, or maybe down to the lower part of your bid range.

Anecdotally, I know we've heard or Don has mentioned that some participating resources have indicated that the dispatch at their plants are smoother and less volatile after having joined EIM. But that's to be determined, I think, for Bonneville and our resources. And you don't have to perfectly hit these, it's a financial consequence. So, if you have the market and also does actually model ramp rates and so one of the things you can do to even try and minimize how quickly the market moves through your offered bid range is by limiting the ramp rate of those bids, essentially. So, it moves slower. And so there's a bunch of little levers that you can kind of move and that sort of make it operationally work better for your resources.

PARTICIPANT: One of the things that we want to make sure that we don't do is if we join, we put ourselves in a position where we're turning units off and on all the time. That would not be a good outcome. But to the extent that there is additional wear and tear that is identified as a result of this, that's something that we could put into our price curve, too, to make sure that we actually recover any additional costs that are identified by that.

RUSS MANTIFEL: And then, you know, just to clarify, the market is going to dispatch you based on what you make available to the market. So, if there are operational scenarios that you don't want to occur, you ought to be able to reflect that in your bid curve. So, if there are certain levels of movement or configuration changes turning off and on that are sub-optimal, you ought to be able to bid in a manner that prevents that from happening. The market only sees what your bid curve is, and so it's incumbent on the generator owner or marketer or whoever's submitting the bid to bid in a manner that doesn't put you in a situation that you don't want to be put in.

TODD KOCHHEISER: Yeah, that's a good point. And, I mean, there's an interplay between your bids, your bid range, and your flexibility and ramp rates with passing the resource efficiency test, so these things all have interesting interconnections with each other. So, it is a complicated balancing act between how you bid, how you want to operate, and the consequences that has towards your resource efficiency evaluations.

ROBERT FORD: I just wanted to point out that if you're talking about cost considerations, those movements by the generators, we've got to – the controls for our generators are state of the art, but the actual powertrain is still 60s and 50s.

TODD KOCHHEISER: Three in the tree.

ROBERT FORD: Exactly. It's like the Starship Enterprise being powered by a '56 Chevy. But those need to be put into cost. And what we've seen in the Corps is in the past is when we try to make our generators more responsive, it ends up costing us more in maintenance and outage issues.

TODD KOCHHEISER: Right.

RUSS MANTIFEL: A really good bidding strategy is inclusive of those costs, right? And that's something we've learned from talking with a lot of EIM Entities as well, and know it's going to be a challenge, but it's something that we've identified as something that – a challenge that we would have to address as part of implementation.

PARTICIPANT: I mean, this may be a boon for us, okay? Because there's certainly going to be a lot more visibility of what's coming up. So, the look ahead is going to be more intensive. So, like you said, the worst thing we want to do is turn a generator off one five-minute period, and then turn another one on in the next five-minute period.

PARTICIPANT: And as you say about the current world, where we're basically balancing all of the wind in our BA with hydro resources. That should be a lot different when we join the market. As Todd mentioned, it's really only when you're setting the price or on that threshold of setting the price between interval to interval is really when you should see a significant change. My hope is that we'll end up with smoother operations.

RUSS MANTIFEL: And the 15-minute market commits and decommits resources. There's a lot of different ways that you can model that for a hydro system. There will be a lot of discussion about the right way to do that. But, you know, part of the benefit of the market is if the commitment of a resource has a really significant incremental cost, you might be able to bring in a third-party resource to bridge that, right, and resolve that so that you're not having like a herky-jerky dispatch or committal or decommittal of resources.

So, there's ways to screw it up, but if you do it well, it ought to be better, right? But you always have the option of doing your job poorly, and we're going to try to avoid doing that.

TODD KOCHHEISER: Don, did you want to jump in and say something?

DON FULLER: Thanks. I think you've actually covered it pretty well, but to Bob's question, you know, the concern of what the market will do to resource movements and does it cause extra strain on them has been a very common question from all resources, and especially the hydro resources.

The case that Todd mentioned was actually one that Portland General studied a couple of their units before and after EIM and they've published that. And it showed a smoother operation after they joined EIM, but also to your point, I think it was a combination. EIM didn't do that all by itself, it was together with the bid strategy that they utilized, but were able to see a smoother operation of the units. Thanks.

TODD KOCHHEISER: Great. Well, I think that's probably good that we maybe move on at this point. I want to move on to resource efficiency, we've been dancing around it. So, I want to introduce Frank from Transmission Operations.

FRANK PULYEART: All right. As Todd said, I'm Frank Pulyeart from Transmission Operations. And I'm going to cover the resource efficiency or the best that I can.

First off, and as Todd mentioned earlier, the EIM is not stepping in to serve your reliability needs. It is not intended to fulfill that gap. They are actually forbidden to do that, and so the resource efficiency is there to ensure, really, that no EIM Entity is leaning on the EIM for that capacity, flexibility, transmission to serve their reliability obligations. You're still responsible for your Balancing Authority for ensuring your ACE is correct, all of your BAL standards are still your responsibility. This is helping you more optimally serve the imbalance in between.

But, really, if an EIM Entity passes the RS evaluation, they're allowed to essentially share with other Balancing Authorities. So, you'll get that most optimal dispatch of imbalance across BAs. But if you fail the RS evaluations, you will be limited in how much you can share.

Now, you won't be completely cut out, you are limited to the prior hours transfer level. We'll get into this a little bit more as I work through things. One key thing to note is that the market, even if you had zero transfers the hour before, the market will still optimally dispatch your own resources to meet your own imbalance within your Balancing Authority. So, it still optimizes your BA, it still gives you the same information as if you were cut out of the market or limited out of the market for failing.

So, the resource sufficiency tests, as Todd just went over, they are performed at 75 minutes prior to the hour, 55 minutes prior to the hour, and 40 minutes prior to the hour. There are four resource sufficiency tests. The first three are, I would say, interrelated as they're listed here, and sequential for a reason. The balancing tests, the big capacity tests, and the flex ramp sufficiency test. The last one is separate, but still ties into the resource sufficiency, and that's the feasibility test.

It is performed for all balancing authorities, including the California ISO Balancing Authority. They are subject to it, just as everyone else is.

The balancing test, starting off with the first one ensures that every entity is coming to the market balanced for the operating hour prior to that operating hour. It compares your base schedules – so it's just your generation base schedules, what your resources are planned to operate at, plus interchanges. So, imports are a positive, exports are a negative to that with the hourly demand forecast.

If you pass this – well, deemed passing this test is having your imbalance within – sorry, that balance between those two sides, and I have a diagram on the next slide, if that's within 1 percent, then you're deemed to have passed the test. Failing the test puts you into being subject to the over- and under-scheduling penalties. There is ratchets on the over- and under-scheduling penalties, so they don't apply until you're 5 percent difference between the forecast you provided for the test and actual after-the-fact load that was measured after the fact.

So, the two options kind of on this is if you elect to use the ISO's forecast, that pass actually applies to you. If you don't elect to use the ISO's forecast, you're kind of always in the success, but you get the failure consequence. So, it's definitely set up such that the CAISO forecast would be a preferred option. Question?

QUESTION: The first one would be: Do you have a leaning as BPA which forecast you prefer or you're looking at more than the other one?

FRANK PULYEART: We have no leaning at this time.

QUESTION: Okay. And then, secondly, is the penalty not just a financial penalty, or are there consequences for consistently not passing that test?

FRANK PULYEART: For the balancing test, the consequences are completely financial and you can look up what the over- and under-scheduling penalties are on the business manuals for the CAISO. I would say if you have a large error, they are hefty. So, you would want to make sure you're not in that 10-percent band that's currently listed out there. I won't say them directly, because things change really fast out there. It does give an incentive for that, electing the EIM forecast, I would say, as a personal preference or opinion.

So, this is actually two different representations of the balancing test. Both should be pretty easy to follow. You have a forecasted demand for the hour, this is an hourly test, if it wasn't mentioned before, and that is compared to the base schedules plus the interchanges.

Focusing on the right diagram, you have the resource stacks. Those are the base schedules for all your resources in your BA, plus the inter-tie schedule stack, which again, could be a positive or a negative based on imports or exports, and that's just compared to your demand forecast. So, pretty simple test.

Again, if you're within that 1 percent, you pass and you're not subject to the over- or under-scheduling penalties if it's the CAISO forecast, otherwise you are subject to over- or under-scheduling if your error after the fact is greater than the 5 percent realm.

(Break for direction.)

FRANK PULYEART: Okay, moving on to the second test is the bid capacity test. Really, they're sequential, these three tests, as I said earlier, because they somewhat build on each other and the diagrams that I'll go into help explain that a little bit more. But this test is a comparison of the aggregate INC/DEC bids from participating resources from within your BA added to or applied to the base schedules versus the demand forecast, which also has an adder, which is historical inter-tie deviations. And I'll explain a little bit more of that later.

Passing this, you pass this particular test and you move on to the next test. If you fail it, you automatically will fail the Flex Ramp Sufficiency Test, and you will be limited in the direction of the failure. That means that, for instance, a failure on the INC side in this test will limit the import ability to bring in other people's transfers, ETSRs from other entities.

So, again, there's more on the failures and the Flex Ramp Test side because that's the last test, I cover more of it there.

Now, to work through this diagram a little bit. You'll note that the two rectangles, basically, that start from the bottom up are actually – sorry, there's a question on the phone.

QUESTION: (Inaudible, off mic.)

FRANK PULYEART: So, the question on the phone was: Can I confirm that the balancing test at which the penalties actually apply on is the T-40? And that is correct, because the last go at it for the EIM Entity can make adjustments to the base schedules, which it's the base schedules that are used for settlement purposes and that is the last go at that test. So, your after-the-fact demand for the hour will be compared to your base schedules at T-40 to determine if the over-and under-scheduling penalty applies is my understanding. I caveat everything with "my understanding."

Okay. So, jumping back to slide 63 here and the two diagrams. Really, the green on the right is the same as the green on the bid capacity test. The blue on the left in the bottom is an addition of the two boxes I had on the balancing test added to your left is your INC and DEC bids. So, your DEC bids are, obviously, going below that base schedule, which would be the top of the larger blue box and your INC bids are added to that.

That is, then, compared to the demand forecast with a similar overlay of imports uncertainty adding to the requirement, export uncertainty taking away from the requirement.

Now, that uncertainty there is actually – CAISO does historical histogram. They do a P95, so 97.5 percentile, and a 2.5 percentile on that histogram. And that histogram is measuring how much did your plan deviate from your T-40 last submittal for the resource sufficiency test and that T-20 tag deadline? So, if your imports say, historically, you had a deviation of imports decreasing from T-40 to T-20 by 100 megawatts, that would add 100 megawatts to your import uncertainty, and vice versa on the deck side.

And, really, what the CAISO is going to say is – and in this particular – sorry, the EIM is going to say. I apologize, I'll screw that up again, I'm sure.

But the difference between these two, they're not equal. The green box and the blue box are not equal in this diagram on purpose, and that's you're now in the bid capacity test and really what they're looking for is do you have enough INC and DEC bids at which you can meet the band on the other side? So, can you live within that band?

And another way to – sorry, I'm getting my tests confused here. Really, if you're unbalanced enough, your import/export could be all within your INC or all within your DEC, but I'm getting into details I don't need to get into. I'll try to move us along here. So, are there any questions on the bid capacity test before I move on?

JIM FARRAR: Frank, this is Jim Farrar at TID. How often do those import uncertainty and export uncertainty values change? And are they a function of what you have scheduled at T-40?

FRANK PULYEART: So, they are a function of the demand forecast at the T-40 mark. At every mark, the demand forecast is going to be the base starting point. So, at T-75, it'll be the T-75 forecast and so on to the T-40, we'll reference that.

As far as how often the historical uncertainty deviations are calculated, that's still a pending question I have on how often they're calculated and at what granularity. I'm not sure if those are based on the period of the day or if those are a general rollout.

When I talk about uncertainty under the next test, there are some definite breakouts of how they break out the data according to uncertainty, but I don't have information on when the update frequency is or what other criteria they might put into the historical inter-tie uncertainty, other than it's the T-40 to T-20 changes.

JIM FARRAR: Thank you, Frank.

FRANK PULYEART: If anyone else in the room does, okay.

JUSTIN (PACIFICORP): This is Justin (inaudible) from PacifiCorp. It's an hourly additional for the uncertainty, and it is updated at the monthly value for each hour of the day. And it is determined from the last three months of uncertainty. So, basically, for this month, we'll have one value for the uncertainty import and export for each specific hour.

FRANK PULYEART: All right, thank you.

JUSTIN (PACIFICORP): You're welcome.

FRANK PULYEART: That covers that. So, updated monthly, and it covers it's an hourly value and it's based on the last three months.

JUSTIN (PACIFICORP): Correct.

FRANK PULYEART: Thank you for answering that.

Okay, now I'm going to be moving on to the Flex Ramp Sufficiency Test, which they're increasing in complexity here. This one definitely ratchets it up.

So, this ensures every Balancing Authority in the EIM has enough ramping resources to be able to meet expected upward or downward ramping needs. INC and DEC are considered separately, so your ability to go up versus the ability to go down, and every 15-minute interval is tested separately as well. It's formulated for all the balancing authorities in the EIM as well as a number is run on the entire EIM footprint.

If you pass, your resources are capable to meet those requirements, and you are allowed – you are given a diversity benefit for being part of the larger EIM footprint, but that is limited to the available of import and export transfer capability offers. So, if you have not offered any transmission to move ETSRs, you won't be able to get a diversity benefit. So, there is a limitation there.

If you fail this test, your EIM transfers are limited to the last 15-minute market run for the hour before, so that's' the T-7.5 operating point of the FMM. So there is the RTD, the real-time, the five-minute dispatch, this is the FMM run, not the RTD run.

And it is possible to fail in only one direction, and that would just limit the flows in that direction. And you would not – so, if you failed in the INC direction, your ability to import would be limited but your ability to export would not be limited.

So, the data that's used for the Flexible Ramp Sufficiency Test is it does start with the initial participating resource operating points from that T-7.5 point. So, for the first two tests, the T-75 and the T-55, the only data available for that last 15-minute market run from the prior hour is the advisory solution. The binding solution is available for the T-40 run, and so the binding solution is used for that last run at that.

Participate resource energy bids and ramp rates are used for this test, and the variable energy resource and the demand forecasts are run at 15-minute intervals for this test. It includes, now, talk a little bit more about the uncertainty component that this test includes. It has a historical histogram of the Load net VER difference from the last advisory 15-minute run to the binding five-minute runs for that hour of the day. Similar to what Justin said, it's a histogram of the past – I think it's about the same amount of time. I think it's basically 90 days, but weekends and weekdays – sorry, weekends plus holidays are separate from weekdays, and then it's an hour-of-day analysis that's run and it creates these requirements for how much uncertain you have in your load and variable energy resource forecast versus what actually is produced.

It is reduced, as I talked about in the prior slide, by the EIM diversity benefits. And that is also capped by the available import and export availability, so that's offered transmission. You also receive a reduction for the amount of import or export that next import or export transfers at that T-75. So, if you're exporting 100 megawatts, you get credit for that in the market. Yes?

QUESTION: With respect to variable energy resources, do you have a leaning or thought one way or the other at this point as to how variable energy resources within your Balancing Authority, but owned by others, would be treated? Would they just be on their own in terms of dealing directly with the EIM? Or would you be, you know, for example, so long as you take the BPA super forecast, you'll just count them as one of your own?

STEVE KERNS: That will be a great topic for a future workshop.

QUESTION: Okay. So, you don't?

STEVE KERNS: We don't have anything to share at this point on that.

QUESTION: Okay.

FRANK PULYEART: Yeah, as Steve said, we'll be discussing that more and have a further workshop on that.

Now I'm going to get into one of actually three examples to run through on this test. The first and second example are just different takes at it. This is probably the most complex.

Really, I'm going to start by working through – I'll talk about the red lines first. So, the solid red line is your demand forecast on a 15-minute increment throughout the hour. So, you can see how the middle of that 15 minutes is shifting. That's the 15-minute load forecast across the hour.

The dotted lines above and below that are the uncertainty components applied to that line. So, they are static throughout the hour. The uncertainty components is an hourly calculation. So, it's the same amount for every 15-minute increment, but they don't necessarily – it's not necessary. Plus or minus 50. It could be plus 50 and minus 25, or it could be plus a lot more than that and minus a lot more than that, too.

With that, that's the measure that you're trying to meet, and now you have to stack up your resources for each 15-minute increment.

Starting with the gray and working up, so let's ignore the variable energy resources in the interchange first. I deliberately made these four gray areas identical to help not have too many things moving around on this diagram, but you'll note that this is really similar to something that Todd presented earlier, where you have just some base generation, there's no flexibility in it, you have your regulation down requirement stacked below your flexible ramping range. So, there's INC and DEC within that range. You have your regulation up and your contingency at the top.

Really, the goal of this test, so if you had no interchange and no variable energy resources, your goal would be to make sure that those red lines, the dotted red lines, live within the orange. The variable energy resources and interchanges throw in a little bit of a different wrinkle because those can be changing every 15 minutes, and so that is reflected in this test. So, essentially, your more static historical resource stack is moving around as you get through the hour, and as you can see here, the test is passed across the entire interval of the hour here, but the variable energy resource and the interchanges are moving from hour to hour.

Technically, if you submit 15-minute base schedules for some of the gray, the top, your gray boxes could be moving around as well. So, there's quite a bit of moving parts. I chose to exclude at least one for this test.

So, really, that INC/DEC bids have to cover that expected load plus that uncertainty. And, again, your uncertainty is that P95, so it's 2.5 percentile, and 97 percentile of that load net variable energy resource deviation.

Another way to look at this, which is simpler, because it gets rid of some of the movement or aggregates some of the movement, is essentially the dotted line on this slide, slide 67 here, is the T-7.5 starting point. It's the last 15-minute market run of the prior hour. From that, on the right side, you have your changes in your load net VER forecast and interchanges, so how much is your system moving around or projected to move around across the hour? And then added to that, you have this uncertainty INC and DEC. And you can see here that your entire uncertainty, you're being tested based off of how far your uncertainty goes above and below that change. It can live completely in your INC or your DEC bids that you have submitted to the market, as I've got demonstrated here. Each 15-minute segment is tested separately, and currently, if you fail one of the 15-minute segments, you fail the entire hour. I say "currently" because there are some proposals in one of the – it's an enhanced day-ahead market, or the day-ahead market enhancements, I'm not sure which one. Russ is better with that.

So, one last thing, and the last diagram I have on the Flexible Ramp Sufficiency Test addresses a little bit more on the ramping needs. So, part of this test is actually making sure that the submitted participating resource information can actually ramp to where you need to go. So, starting at that T-7.5 point, do you have the resources to be able to meet the things that I showed in the prior slide? Can you ramp to the T+7.5 point? Can you ramp to the 22.5 point? To the 37.5 point? And, lastly, to the 52.5 point?

Maybe you just don't have enough to ramp to that end-of-the-hour point that is 60 minutes from the time that it's being evaluated against. So that last FMM run of the prior hour, can you get from that FMM run to the same point in the following hour? So that, again, is another element that this test incorporates. And so if you pass all of those, you pass the sufficiency test, and you can move into the hour. If you fail any of those four increments, then you're back to being limited in the direction of the failure.

PARTICIPANT: Frank, do you mind if I add a clarification just to make sure people understand? These tests are for the Balancing Authority area, so Bonneville, we're going to be focused on the FCRPS, but non-federal generation that's participating in the market, if they bid, that goes towards this calculation as well. So if we have IPPs or non-federal-associated generation that submits bids, those count towards the test as well.

FRANK PULYEART: That's correct. So, all of the participating resources within your EIM Entity area, your Balancing Authority, go towards this test.

Now, I'm going to move on to the last test, which is the Feasibility Test. You could also call this a Transmission Feasibility Test. And, really, the Feasibility Test is actually run on the day-ahead market as well as in the real-time market. The day-ahead market uses the day-ahead market-based schedules and the real-time test uses the actual submittals of the base schedules at the T-75, T-55, and any revisions that might occur for the T-40, the day-ahead market schedules are not used in that.

So, I'm going to jump below the pass and the fail, so pass and fail is pretty explanatory here.

The consequences, it does say "none." There are no direct financial consequences for failing this test. There are a bunch of natural consequences which can result in financial aspects that this test has.

So, really, this test, if you fail it, it shows that there are – it's a high potential for congestion on your system, a higher potential for what they call an "infeasible" solution, where the market model can't serve all of your load with the generation that's been offered. And including the consequences are – could be it'll implement the transmission constraint relaxation, which essentially means the dollars per megawatt to serve your imbalance is going to rise as you fail this test naturally through the way the model runs. You don't automatically get labeled that way, but it increases the likelihood of that substantially.

So, really, if you fail this test and you get notification that you should be revising your base schedules to be able to pass the test in the future intervals.

PARTICIPANT: Or evaluating the transmission element that's been identified as maybe potentially being overloaded, so you might take a look at that, but that's sort of the EIM Entity's opportunity to try and fix things, minimize the chaos and cost of operating with that element, initially overloaded the markets real time, yeah.

FRANK PULYEART: Yeah, so if you're hitting this a lot, you probably want to look at what's driving that to make sure the modeling is done correctly and that something's not misrepresented, including looking at your outage cards and everything else.

PARTICIPANT: And in some cases, it could just be a limit that is incorrect, in which case you get a chance to update that in the market, or it could be a real infeasibility that you should address.

FRANK PULYEART: Yeah. Actually, the next slide is one of the tools that you can offer to the EIM to help you deal with that, and that is the available balancing capacity.

So, available balancing capacity is something that you can designate on your participating or non-participating resources as part of your submittals. It's declared as regulation up and down in that base middle, and it must have an extra checkbox or something that you can identify it as available balancing capacity.

This is conditionally dispatched by the EIM to avoid the power balance constraint or infeasible solutions as another way to say that. And it will only be deployed for the BA that's offering it, so it's only available to solve problems within your own Balancing Authority, it will not be deployed for a neighboring Balancing Authority that's having issues. It's a tool to help you mitigate your costs within your Balancing Authority when you are running up against these types of scenarios. It does not contribute to the flex reserves to the tests I just talked about, it's really more of a real-time tool, and the pricing for what you get reimbursed for that is, according to the bid curve for participating resources or it defaults to the default energy bid for your non-participating resources.

So, it's a tool available to help you in situations where maybe you can't find a good resolution to the feasibility question.

And the last thing that I'm going to cover is contingency dispatch. So, there are two different ways really that contingency dispatch occurs. The first one I'm going to talk about is the CAISO BA. So, any time there's a contingency within the CAISO BA, the entire EIM real-time dispatch is suspended, and they invoke, instead, the real-time contingency dispatch. This isolates the CAISO Balancing Authority from the EIM area and freezes those transfers to the last RTD solution – Advisory Solution, sorry – and actually they do send – everyone gets the last advisory five-minute solution sent to them instead of continuing to run the RTD market until that's resolved.

Similar, but different, is contingencies within any of the other EIM Balancing Authorities, and the CAISO does not dispatch your contingency reserves. You have to manually do that, but the EIM operator will notify the ISO or the EIM Entity – sorry, market operator – that they have a contingency, and then the EIM will isolate that Balancing Authority from the market and freeze transfers, just like they did above for the CAISO BA and freeze them to that last real-time dispatch advisory solution and then the BA is able to incorporate manual dispatch instructions into that to solve for the contingency until it's resolved.

All right, questions? One on the phone it looks like? No? Maybe?

STEVE KERNS: Thank you, Frank. We a section here on settlements. Or do we hear something on the phone right now? No? Okay, we're good.

TODD KOCHHEISER: Thanks, Frank. We are, unfortunately, running out of time, for those that are up here talking. We are going to have a truncated Q&A, unfortunately, but most of us can stick around for as long as you want and answer questions.

This is EIM settlements that we want to finish with. This is a non-trivial topic. We're going to have a future stakeholder meeting to do more of a deep dive on this. There are quite a few policy and technical questions that we'll address at that point.

Generally speaking, make sure I'm in the right section here, EIM settlements is really the process of resolving and the invoicing of charges and credits for participating in the EIM. And, you know, the natural sort of order people often think of this is, you know, is the pre-settlement market operations feedback part. This is a critical part of people's operations where they're taking essentially the previous hour, the previous day's information, dispatches, and using that to analyze profits and losses if you were a participating resource and using that information, then, to incorporate that into your new current operations as far as how you're bidding and how you're participating in the market.

Otherwise, there's the settlement-related data submissions and collection. So the biggest one of these is submitting meter readings and after-the-fact interchange data, for example. So, settlement-quality meter data.

Most people run a shadow settlement process if you want to validate the invoices that you're received from the CAISO or from the market operator to see that they're accurate. And then there's the invoicing of the EIM charges and credits, these are to the EIM Entity scheduling coordinators and the participating resource scheduling coordinators. And, of course, then the payments and the receipt of any funds or charges or credits.

And then, finally, there's the settlements-related dispute management process. And so these are very complicated timings, and we're unfortunately not going to cover them in great detail today, because we want to leave you wanting for the next meeting.

But from a transmission customer perspective, interacting with an EIM Balancing Authority, the financially binding basis is typically T-57. I sort of mentioned this earlier, that is in most of the business practices I think for existing EIM Entities that the submittal timeline is T-57, to the extent that data doesn't change between then and T-40 when the market runs, that effectively becomes the financially binding basis for settlements.

There's four general categories of settlements. For load, it's the difference between the scheduled demand and the metered demand, and that's settled at the load aggregation point. This is typically one load aggregation point for each balancing authority. I think that's how everybody has chosen to do it based on a load-weighted price as well. So, it's sort of settled as net on whole. You don't have to do that, but that's what everybody's chosen to do, and it's certainly a simplification that I think seems appropriate.

Non-participating generators, this is the difference between the base schedules and meter generation and it's settled at the Locational Marginal Price at an applicable pNode – pricing node. And that is a settlement that happens between the market operator, the California ISO, and the EIM Entity scheduling coordinator. And then they get to decide how they're going to pass that on.

Participate resources, we said before, they settle directly with the CAISO at their LMP for awards and deviations from their operating targets.

And interchange, again, this is typically going to be based on your e-Tag at T-57, and any subsequent tag changes before or during the hour and settled as instructed imbalance energy.

I mentioned here that there's a very complex feature that's available called auto-matching that I'm sure we'll be evaluating, but it allows the EIM Entities to essentially self-balance non-dynamic schedule deviations that happen after T-40 with non-EIM balancing authority. So, that's some way to mitigate some of that risk. We'll certainly be looking to see if that's a tool that's applicable or appropriate for us to consider.

The settlement basics continued. There are approximately 60 billing determinants or charge codes. There's a link down at the bottom to a charge matrix that's pretty thorough and complete. It'll show you which charge codes are related to the Energy Imbalance Market specifically and whether they're participating or non-participating resources and categories of participants. 26 of those are generally for resources, 34 are the EIM Entity scheduling coordinators.

There's really three charge codes that form the basis of the vast majority of the dollars that move around in the Energy Imbalance Market, those are essentially the instructed imbalance charge codes for participating resources and non-participating resources. There's one for the 15-minute market and there's one for the five-minute market with two charge codes.

And then there's another charge code which is the uninstructed imbalance charge code. This applies to participating resources, non-participating resources, as well as loads. And it's the difference between the hourly meter and base schedules for non-participating loads. And it's the difference between the metered and the expected energy, or your real-time DOT for participating resources.

Now, this is the general high-level timeline as far as the settlement process is concerned. Most of the time, you're going to see in these settlement processes, T being a day, so T+12 days, T+3 days, et cetera.

So right at T+48 days, that's when the settlement quality meter data is due. I think prior to that, there's usually submittals of meter data as well, it's just not considered settlement quality until T+48.

I think there are also some consequences for late submittal of settlement-quality meter data. Make it sound like you don't want to be late, so you want to definitely get those in.

And, again, there's resettlements, and these processes kind of go on for a long time. There's a really nice table that you can find out there that shows dispute timelines for all of these basic settlement milestones.

And I said before, I might just say it one more time, that as a transmission customer, a non-participating resource, as a non-participating resource or load, basically anybody other than a participating resource, you don't have a direct financial relationship with the market operator, with the California ISO. Your relationship is with your transmission service provider. And so any disputes that you might have with a charge that's past due to you, you basically need to work that today back through your TSP and basically have them carry your water back to the California ISO as part of any sort of dispute process.

As a participating resource, it's different. You have a direct relationship with the California ISO and you can submit disputes directly.

A bunch of other settlement categories. These make up those other 57 charge codes. Over/under scheduling of loads. Again, these are some of the typical ones. There are all sorts of different uplifts that are also allocated to the EIM Entities – market neutrality, congestion offsets, marginal losses, neutrality payments, et cetera.

And we have somehow magically left five minutes for an open Q&A, but actually if there's any questions on settlements, I'd take them now.

(Break for direction.)

STEVE KERNS: Let's start with settlements questions, and then we'll open it up to broader discussion if we have some more time. Anything for Todd on this? It's all crystal clear?

TODD KOCHHEISER: Like I said, hopefully we left you really wanting, you're going to come back really excited to do a deeper dive on settlements in a month or two. I'm not sure exactly when we're planning that, but I think it's our next meeting or the meeting after that.

Just before we get into any open Q&A, I want to tell you again that these are the dates for the currently planned next meetings. October 11th and November 20th.

And we do want feedback. Please, do submit your comments. That would be helpful for us.

Before we get into Q&A again, in the appendix, there's a lot of additional material. There are some really good links. I think the CAISO has done a very good job in providing a lot of educational material in all of these topic areas. I urge people to go out and read those. Otherwise in the appendix, there are some examples of kind of with and without an EIM. There's an entire section on a very simple explanation of the formation of LMPs, so you can read that, as well as a simple participating resource settlement. So, those are all in the appendix. We're not going to cover those today, they're for your reading enjoyment.

STEVE KERNS: Okay, we have verified that we do have another 15 minutes if we want to talk a little bit more, so let's open it up to broader discussion. Ed, go ahead.

QUESTION: Yeah, I'll throw out a settlement question. On uplift charges, you kind of hear a lot about those. Any sense on how often those are assessed? Magnitude? Things like that?

TODD KOCHHEISER: No, I don't, except probably all the time. There are micro amounts of them probably on all these charge codes, sometimes they're just not that significant. But at times, I think they can accumulate rapidly. That's why you do need to be actively performing that first step in the settlements process where you're actively looking at your settlements statements that you're getting out of the CAISO and adapting or modifying your bidding behavior and participation to make sure you're covering those as quickly as possible.

RUSS MANTIFEL: That's a good question. We can take that offline and get answers to exactly when the intervals –

TODD KOCHHEISER: We do have people in our billing department for transfer loads and generators that are in EIM Balancing Authorities today, they have a lot of experience with those other charge codes and charge categories, so it is something we can certainly take as input to our future meeting.

STEVE KERNS: Any questions?

JIM FARRAR: Todd, this is Jim Farrar. Do you expect difficulty in allocating some of those costs that are going to be charged by the EIM market, such as uplifts, to participants within your BA?

TODD KOCHHEISER: I think that's one of the things, obviously, that we will have to figure out as part of our stakeholder process and one of the things we'll be starting to articulate in an upcoming stakeholder meeting are the options around the allocation off those charges. Ultimately, the final decision on things like that is going to occur in any case. So, that's ultimately where those decisions are finally made that we certainly want to see if we can steer ourselves to a good landing there if we do decide to go in. Yeah.

JIM FARRAR: Thanks.

TODD KOCHHEISER: We certainly know what it's like to be a transmission customer in other Balancing Authorities that are participating in the EIM that are EIM Entities. So, we're not naive at all about different ways that can be done.

STEVE KERNS: Okay, last chance. And we didn't need the extra 15 minutes. We hit noon right on the dot. Nicely done.

QUESTION: Todd, I have another question for you if nobody else is going to ask.

TODD KOCHHEISER: Of course you do.

QUESTION: One of the attendees made a point that the EIM is just for dispatching imbalances. And I wonder if you can tell me if there is a difference between the EIM and a security-constrained economic dispatch that goes beyond simply –

(Crosstalk.)

TODD KOCHHEISER: Oh, no, I'd say that's kind of wrong. It is a maximal redispatch to optimally serve load and imbalance based on the voluntarily offered capacity of bid and resources. So, it is not just serving imbalance, it is attempting to find the most optimal dispatch of offered resources to serve the load obligation of the EIM area, the entire market footprint. So, that would be literally the load of all of those Balancing Authorities participating in the market plus the net export from the EIM market area. That's the load obligation of the market footprint, and it's going to try and find the most optima, most economic way to serve that load obligation.

RUSS MANTIFEL: Yeah, Jim, this is Russ. That would include even if you had zero imbalance for any given interval, you could have a significant amount of EIM transfers and redispatch based on the economic solution. Imbalance looks like a load, in fact, for the market engine. And, yes, it's a maximum economic redispatch for load service in which imbalance is one aspect of the load.

TODD KOCHHEISER: Right. The charge codes kind of imply, if you look at them closely, that there is instructed imbalance energy, that's one of the charge codes, IIE. That's the market instructing a resource, INC or DEC, based on, in some cases, maybe purely economics. You're an expensive or you're a cheap resource relative to another one, subject to all the constraints. We're going to redispatch you with another resource to be more economic financially across Balancing Authorities. So, again, it's a pull optimization. Yeah.

QUESTION: Thank you for addressing that.

TODD KOCHHEISER: Thanks. I think I heard that earlier, too. Which is, you know, how you derive a lot of the benefits as well out of the Energy Imbalance Market. And what's just imbalanced, that's sort of a relatively smaller problem.

Any other questions? Hearing none, again, if you do think of some later, please feel free to submit them to the Tech Forum e-mail address.

STEVE KERNS: Thank you all very much. We'll look forward to seeing you again in about four weeks.

END