Introductions, John Lyons

John Lyons: We do this for the recording and the plan is we post this after the meeting. So, in case there's something you want to check in on again. We also use it for the transcription, so, we're able to have some pretty good notes. James, you want to pull up the first presentation.

James Gall: I will try. That's it.

John Lyons: The first one in the new rooms. Plus, you will notice, we did give a second meeting invite here within the last week. That's because we've done a major shuffle on our conference room numbers with the technology. It changed all the room numbers and then resent things out. Hopefully we should be done with that. But if you've had any Avista meetings previously scheduled from more than a week ago, you may see that happen with the new rooms. I'll start away with the introductions, the first slide.

John Lyons: Meeting guidelines for the Technical Advisory Committee. IRP team, we are back in the office and Avista is back to at least three days a week in the office. Some people are four or five. We're in office Monday through Wednesday and also available by email, phone and Teams. We'll talk about that later today. There's a lot more involved with Teams, where you'll be able to interact with us, hopefully more. We'll be able to post new data as it comes out. This is where we get our stakeholder feedback and we share those responses. We'll share them at the TAC meeting, so if we had a question come up that we have to go in and figure out what did we do last time, we'll be able to pull that to share the next time. Some of them, though, we will be sharing through Teams and then we also post all, and print all of those in the IRP appendix so they'll be there for posterity's sake. It also does help all of us to make sure as we go through all these meetings that we're picking up on everything that we've been that we talked said that we were going to do the working data is going to be posted in Teams.

John Lyons: Last time it was we posted on the website. James will be talking about that a little later today. It'll be posted on Teams so we can update it a little more quickly when the data becomes finalized. It will still be posted out on the website as well, and then we will send it out to the TAC. So, like the Work Plan that got sent out with this TAC meeting. We are going to always offer the virtual IRP meetings on Teams, and we will offer in person for the full day meetings. Internally, we'll be here in person, but the external ones, the six plus hour meetings. Final TAC presentations, meeting notes and the recordings will be posted to the IRP page just like we've done previously.

John Lyons: And some reminders on the virtual tech meeting asked that you mute your mics unless you're speaking or asking a question. We do also try to watch for people as we see it pops up that they've taken their mic off, will try to call on you and we've got folks here from Avista watching that. If we don't get to you right away, it usually just means we're trying to find a good breaking point. There is a raise hand function you can use, or you can type questions in the chat box if it's one that is helpful for everyone, we'll just answer those to everyone. Otherwise, we may just answer them right in the chat. We asked you the respect, the pause. We've all gotten fairly good at working on these virtual meetings, but it's still does help to give people time to get through the technology, unmute things like that. Try not to speak over the presenter or a speaker, we know that's difficult, but we all strive to do that. And if you can state your name before commenting for the note taking software. Usually, it's pretty good about picking up who it is that's speaking if they're up to a direct computer. When you're in a room or you're using another type of microphone, sometimes that's a little helpful there. Just as a reminder, this is a public advisory meeting and we do record all the presentations and comments for posterity's sake. So, if you have something you really want in the IRP, that's a good way to be able to do it. If you don't want it in the IRP, probably best not to.

John Lyons: On the IRP itself, this is required by both states we operate in. Idaho and Washington. Every two years in Idaho and in Washington it's essentially every four years we do a full IRP and then the intervening 2-year period we do a Progress Report which looks very much like a full IRP. But since we're already doing it for Idaho, we do a full IRP. There are just a few nuances we do for Washington. And in that case, a lot of that has to do with the Clean Energy Transformation Act. As we've moved that direction, the IRP informs the Clean Energy Action Plan and the CEIP looks at the resource strategy over the next 20 years. If you've been with us for a while, you notice it was 20 plus years because we were going at least through 2045 to coincide with CETA. Now we're into that period where we're within 20 years, so, we're back to our normal timeline on that. We look at current projected load and resource position. What resources we have in place. What is going to be leaving us, like ending power contracts, things like that.

John Lyons: Looking at load growth and where load growth is occurring and what we're going to need to meet that. We look at alternative load and customer forecasts because we don't know the future exactly because if we did, we would not be talking to you on this meeting, we'd be on a beach somewhere if we were perfect. We do have to make different alternatives. We always start with an expected forecast and then we have high and low. If there are other ones that are important, like for example, do we have a quicker uptake of electrification for vehicles, housing, things like that. We develop resource strategies under different future policies. Again, since we don't know what the future is going to bring, we come up with different ideas of what it could be. We look at different generation resource choices, do we have an all wind, all solar, mix of the two, different types of storage technologies. We are looking for new resources that will be clean but that we can turn on and off, it's hard to do that with the sun and the wind. But are there some other resources like hydrogen of green ammonia, things like that we could look at. We include energy efficiency and demand response, transmission and distribution integration. We do now have a distribution planning group that you can participate in that we'll be talking about throughout this TAC series. This all results in a set of avoided costs that will help developers know what they be able to get if they submit us resources and just also knowing what that's going to be for our general planning needs. We also run market portfolio scenarios for when we have those uncertain future events. Those are the big picture events that will fundamentally change the market that we're looking at.

John Lyons: As far as the TAC itself, this is the public process of the IRP. This is where we get input on how we're going to study things, what we're going to study. If you have things that are questions that you're really concerned about, and you would like to know answers to. If you have a particular study in mind, let us know, or we can help you fashion a study that we could do to come up with that data. We go through all of our assumptions and results. And if you look in our past IRPs, we publish a tremendous amount of data so that you can look through it and decide are we, you know using reasonable assumptions or not, can we make them better? Better we do have a very wide range of participants, so not everyone is going to be very, you know, totally adept at certain parts of it.

Annie Gannon: Yeah, we lost the sound, I think.

Kevin Holland: John muted himself.

Gannon, Annie: Oh, there it is.

John Lyons: Alright, it just automatically muted for some reason. You can hear me again?

Chris Drake: Thank you.

Annie Gannon: Yes.

Charlee Thompson: We can hear you.

Chris Drake: Yep, we lost just the last 20 seconds.

John Lyons: OK, it just didn't like me, and I just had this life changing sentence that I said. But no, this is about TAC members, and we have a wide variety of people in the group and some of them are experts in one area versus another. Please ask away if you have questions because, like we've all learned in in school over the years, if you have a question, generally someone else has it too. So, please speak up and ask on that. It is an open forum. We're always trying to balance the needs of getting through the slide decks. If you just say have something where you agree with someone, do the thumbs up on the chat box. That does help. We also are always looking for help with soliciting new TAC members, and we have an arduous process to get on the TAC. You just send me an email and ask or call. That's it. If you want to be on the TAC, you can be. We have some people that participate for the whole series, and we have others that just come for the topics that are very important to them.

John Lyons: We do welcome request for studies or different assumptions. We may have a set of assumptions that we feel are appropriate for planning because we have to plan to what we actually see out in the market. But if you've got other assumptions you'd want us to take a look at as a scenario, you’re welcome to do that and we’d happy to do that. And again, we're available by phone or email for questions or comments in between meetings. And I think James will talk about it later, but on the Teams, we may be able to start doing some more discussions on that.

John Lyons: Our agenda today, after the introduction, Kelly will go through the CEIP update and what's going on there. Then James will talk about the TAC process and some of the proposals for different methods we're going to be using this TAC series. Mike will give a PLEXOS overview. That's one of the major softwares that we use for the IRP that is new for this IRP. He's going to show a backcast on that towards Aurora. Take a break. Then Lori will discuss available resource options for different types of generation, demand response. You will have to wait for and be excited about the different types of generation like solar, wind, thermal plants, biomass, geothermal, things like that. And then I will finish out the day with the Work Plan. We plan to end by noon. You'll see we have a mix of long and short meetings going over this schedule.

CEIP Update, Kelly Dengel

Kelly Dengel: Good morning. Thanks. OK. But while James is putting that together, I'd like to thank you for inviting me. This is my first opportunity to speak at a TAC meeting. My name is Kelly Dengel. I'm a Project Manager in the Clean Energy Strategy Department and it it's a relatively new group that has been formed to try to keep up with the good work that this team does, also in energy efficiency and energy assistance and community engagement, all of those groups are involved or environmental too. I see you over there involved in how we pull off this Clean Energy Implementation Plan and today's information. It's an opportunity to give you an update on our implementation plan and the biennial. Can you go to the next slide?

James Gall: Yes.

Kelly Dengel: Today I'll share just the highlights of what's in the biennial. And you'll also have an opportunity to review it and provide commentary before we make our final filing with the Commission. You are likely all familiar with the Clean Energy Transformation Act, which informed us creating a Clean Energy Implementation Plan. We made a Progress Report earlier this year based on the 2022 compliance period and then the last item on this slide is actually the biennial, which is required every two years. We'll file it November 1st and it's giving an update to all the specific items we mentioned in the CEIP or the Clean Energy Implementation Plan.

James Gall: Alright, I guess this one is my slide. One of the crown jewels of the CEIP is the transition to 100% clean energy by 2045 and we're trying to show progress over the next four years. The first four years of the CEIP plan. For the first biennial, we are going to be reporting on the targets that we set through negotiation in the CEIP process, which is 40% clean energy compared to retail load in 2022, ramping up to 62½% by 2025. That's shown in the green bars and in blue is the amount of clean energy that's allocated to Washington customers prior to any sales to the wholesale market. In 2022, for example, we generated 71.6% of clean energy or qualifying clean energy compared to retail load. It might be worth noting that we did sell off the difference between the 71.6% and the 40% to third parties, at least the clean energy RECs component of that. We will continue to try to optimize those REC sales to benefit our customers until we are at a point where we need to retire all of the clean energy RECs for our customers. As we ramp up towards 2025, we are bringing on new resources which we talked about in the last TAC series where we acquired contracts. Chelan PUD, the Columbia Basin Hydro contracts, the Clearwater Wind, and the upgrade to Post Falls. We'll talk a little bit more about our resource portfolio in a future TAC meeting, but we are in good shape to comply with the ramp up requirements towards the 100% carbon neutral level by 2030. So that'll turn it over to Kelly.

Kelly Dengel: I mentioned energy efficiency as a large contributor to our CEIP and they have some specific items they've been working on. The first one there related to pilots for demand response and those should be available for people to enroll and learn about in Q2 of next year and it will be a two-year pilot for time of use and a peak time rebate. They also made some really good strides with the Spokane Tribe in conducting energy audits and their administration building, partnering with them to apply for grants, working on a solar opportunity, and also weatherization, common energy efficiency activities. And then the last bullet there, the Named Community Investment Fund is a specific action that I'll talk about later.

Kelly Dengel: But how can that speak to how we can make some of these opportunities that look less economic? Economic by funding them through this fund that we established in the CEIP and put more specific interest and specific focus on folks in Named Communities. Next, next we'll talk about the Customer Benefit Indicators. This is a large portion of the CEIP and how it's measured for us, ensuring an equitable distribution of the clean energy plan, and the benefits and potential burdens and call those non, what do we call those James on energy impacts.

James Gall: Non-energy impacts.

Kelly Dengel: Thank you. We worked with the advisory group, specifically that Equity Advisory Group to establish these CBIs, Customer Benefit Indicators. We have six benefit equity areas. The graphics across the top and 14 CBIs which have resulted in 74 individual metrics underneath each of those CBIs. The CEIP will give a 2021 baseline compared to a 2022 actual for each of these metrics and how we've performed in relation to the CBI and when we go into our next CEIP / IRP plan. We'll be talking about the CBIs and if there's changes, we'd like to make, or additions, we want to hear from folks. So that's something into the future. The next one is about the main Community Investment Fund, so this specifically made space for benefiting folks in Named Communities through the establishment of this fund. And we have $5,000,000 set aside. You can see the five different areas in which we intend to spend this money and that $2,000,000 for energy efficiency that supplements to get over the economic hurdle for some of the energy efficiency projects. And the remainder $3,000,000 is managed by our Community Outreach and Development Engagement group here in Avista.

Kelly Dengel: Next, we recently put an application online. Open to government agencies, nonprofits, and other community organizations to have access to the funds. This online application has had exposure and communication with our Community Action Partners and has been pretty popular. We launched this back in August and we've already had more than 10 applications come through for funding and the intent is to review them and get approval to award monies within 45 days of submission. When we go through this review process, we had talked with the Equity Advisory Group about how they thought these funds should be spent and what was a priority to them about projects. And so, this ranking and you'll see that obviously they have some really important things that catch two number ones or three, two number threes. How they think the money should be spent. We look at all the projects through this ranking lens and try to award in line with what they've prioritized. And you'll see the Spokane Tribe is the number one right there, and many of the energy efficiency and audit improvements and the grant partnering is a prioritized effort. So, we're filling that. And as other projects come through, we'll look at this prioritization list as another way to determine funding and approval.

Kelly Dengel: And the next slide talks about what the requirements of the project at a minimum should have. How does it serve a Named Community. I'm assuming that everyone on this call understands what a Named Community is, or at least the concept. And second, how does it fall into one of the equity areas? And then third, what is a Customer Benefit Indicator that it can impact? And so those things are part of the application process and there are folks that have been made available to help in this application process. If you're unsure on how to fill it out or you unsure about how to find out what your CBI is. Next slide. We have funded, or planned to fund, projects in these areas and under energy efficiency. Of course, you'll see a lot of the Spokane tribe and two big projects under distribution resiliency and improvements to the Martin Luther King Junior Center here in Spokane. Through grant awarding with the Department of Commerce we're able to secure funds to work on a solar and battery storage project in the town of Malden. I don't believe there's a grant opportunity there, but trying to work on a solar and ground source heat pump project. Malden is the town that had all fires not too long ago. They're trying to reinforce and rebuild their town hall and this this will help them. That's what we have to date. The biennial will provide updates for each one of these projects and how much money was actually spent within 2022, through August of 2023, what we planned for the rest of the year, and in the 2024.

Kelly Dengel: The next subject of the biennial is public participation. We were required to file a public participation plan of this, partnered with a company called P3 or Public Participation Partners. They worked with us last year and a little bit in the previous year to come up with a plan of how to engage more customers and overcome the barriers that may limit them from wanting to participate. You could think language is a barrier, or where they're at might be a barrier, physically located. And so, we have updates.

Kelly Dengel: Next slide, James, we have updates based on what we said we would do on our plan and that includes a multi-language strategy for our website and our mobile app. We also want to make a way for customers to more easily engage with us. A lot of times our conversations are one directional. We give you a message, but through the CEIP process, in this public participation, we wanted to be more two-way. So, we're talking about a newsletter and a public forum comment section that we can implement some FAQs and obviously continue to get feedback from our advisory groups. These updates to our websites and particularly the CETA page should be coming in the next year and that is listed in the biannual as well.

Kelly Dengel: Finally, we had a bunch of conditions, 38 to be exact, that we were required to accept during our CEIP approval process. Over the last year and a half, we've been working to complete or start a plan for. The biennial will list each condition and then an update as to what Avista is doing to comply and meet that condition and, spoiler alert, for meeting them all. This is a great job and I think we'll have a nice story to tell. The last slide talks about how you can respond and review this biennial document. The document is available for posting. We're sending it out to all of our advisory groups, and I think James has a plan to put it on their new IRP Teams site. You can direct your comments or questions to me specifically and my email address is there. Please send them by October 13th, and we'll include the comments, questions in some type of matrix with the filing when it goes to the Commission on November 1st. At the end of this slide deck is a listing of all 38 conditions. If you're really interested in knowing what we had to do, you can go read through those. That's my presentation for today and hopefully you're really interested in reading this in the biennial and you have lots of comments for me. Are any questions on the chat? No typed questions? OK. If there's any questions of anybody in person, so hands up or pause this for a second, just in case something comes up. OK.

TAC Process and Methods Proposals, James Gall

James Gall: Well, thank you, Kelly. And I guess I am next, bear with me while I try to find my presentation. And looks like you can see it now alright. Well, as we started a new TAC process, we like to go over some of the changes we have in mind. Specifically, there's some major changes in the modeling software we'll be using, others mean a couple of process changes we'll cover. Also, we'll provide an update on the Action Items from the last IRP.

James Gall: First off, I want to talk about the TAC communication process that we're changing that John alluded to earlier with Microsoft Teams, which we've been using for our meetings over the last couple of years. But we're going to create an actual team that the TAC will be able to participate in. You'll be getting an invite, likely tomorrow, to access the Teams site, so I think you can use it through the same software you're using today to access this meeting, but there will be an actual Teams site that will allow you to see files that we share with you. There'll be a chat function for you to communicate with us or other TAC members that are all available in this. I'd say this really comes back to some comments we had from TAC members that either didn't want to engage or wanted to engage with other TAC members. This allows for each of you to engage at the level that you would like. So, if you don't want to see what other TAC members are saying, you don't need to go on the Team site. But if you want to communicate ideas that you have, maybe articles you've seen, files that you want to share with us, it's an Ave to do that. This will eliminate a lot of the email traffic for the passive TAC members. Like I mentioned, you'll also be able to access all of our recordings and all the messages that are on the Teams site are retained.

James Gall: We, like John mentioned earlier, will continue to post our TAC slides and our meeting information on the website, including the agendas and the slides. We will not be sharing on the website any draft documents like we've done in the past. We'll leave those on the TAC Teams site and then once we file the IRP and final documents are ready, we'll post those on the website as we do today. You should be getting an email and next day to sign up for this new Teams site. You'll continue to get TAC invites through email, but you'll also get one on the Teams site as well. And if you are also a natural gas TAC member, we'll have a Teams site for the natural gas IRP as well that will be actually in the same location on Teams. They are called channels that you'll be able to get to when you open this up, you'll see on the bottom there's an Avista 2025 IRP. There's a general section which you will see any generic comments or chat function, but then you'll have electric and gas options, and you can see there's posts for people. This is where the files, where you'll be getting files, and we'll see how this works. If it doesn't work, we'll try something new, but one thing that's important is to try things, and if you fail, fail fast and we can try something else. So, let's try this and see if it works, and if not, we'll try something else.

James Gall: Another interesting thing that's happened, at least for Washington, we got a notice from the UTC on the electric IRPs that the Commission will discontinue its practice of acknowledging electric IRPs in all cases. The second bullet is a quote from that. Notice we're under CETA, the CEIP must be consistent with the long-range utility’s integrated resource plan and informed by the investor utility’s Clean Energy Action Plan, which is developed in part of the IRP. Therefore, any issues that interested parties may have related to the IRP can be litigated and decided by the Commission as part of the CEIP process. How we see this, the CEIP, which is really a four year look at the Company's future will be the area to comment publicly about IRPs. I think this 2023 IRP did have a public process where there were comments to be filed. I'm not sure that will continue or not, but we are, definitely interested in comments as we go through the process as we have always been. I would say don't let this be a deterrent to comment in the IRP process and it is better that we get any comments or concerns through this process before we get to the CEIP, as the CEIP is definitely more focused on four years and sometimes they have a shorter timeline to get that completed. So, continue to use the IRP process as a as an avenue for advocating as you've done in the past. Idaho will continue to acknowledge IRPs, as far as I know, and that process will remain unchanged. But in Washington, there's a slight change.

James Gall: That's a quick update to different Action Items in our 2023 RP. I want to go through each of these items just to give an update where we're at. The first one is related to a distribution energy resource potential study and that is underway. We hired a consultant, AEG, and they're responsible for determining how much available solar and electric vehicles are on the system and where they are at on the system. And in addition, they'll be looking, as they've always done in the past with energy efficiency and demand response, at a spatial analysis of those potential options. For those of you that are following the DPAG process of it, which is the Distribution Planning Advisory Group, that will be the avenue for much of the work that's being done in this DER study. The plan is that any learnings we get from that study, whether that's changes to our load forecasts such as future EV or rooftop solar adoption that will be impacting our load forecast, and then we can use potential resource locations for future generation sighting as well. More to come on that, there will be a TAC meeting in the future to cover this topic. Once that report is complete, the next item is a variable energy resource study. That process was kicked off in the last IRP process and we are continuing to determine the required reserves and the cost of variable energy resources. We hope that the study will be complete for the 2025 IRP.

James Gall: The third bullet, which is alternative load forecasting methods. Again, we were looking at end use forecasting as an alternative to our historic load forecasting methodologies. We did also work with AEG. AEG who does our energy efficiency analysis for us for the potential study does do an end use load forecast, it determines those energy efficiency targets. We're going to be leveraging that work to help us do our long-term load forecast. It's going to be five years out towards the future, so we'll continue to use our existing methodologies for load forecasting for the first five years of the plan and then transition to the end use model for the long-term forecast. And the reason for this is if there are changes in customer use from potentially electrification, this is a better way to forecast that energy use because you're taking into account the types of equipment consuming that load. So more to come on that as well.

James Gall: The last bullet on the left is investigate PLEXOS, which we'll have a presentation about that later today. So, I'll skip that one, and the next one is with the Western Power Pool’s WRAP program. I'd say this was very unique in its last IRP process to use the WRAP’s QCC methodology and we did not use their proposed planning reserve margins for long term planning but I think that the idea here in this Action Item is to ensure that we want to keep using their methodology and then how do we transition to using, or should we be transitioning using the WRAP’s planning reserve margins. There are two concerns with using their planning reserve margins. One is they only go out in the future for two or three years, and second, they have not done any long term QCC analysis. Our PRM analysis determined resource adequacy beyond those first two years. There's been an effort by the members to do a long-term study and that study would be determining QCC values likely out in the 2040 time period or 2045 time period and what the required PRMs would be out in that future and that would be used for planning in the IRP. If that

that process is successful, so likely there will be a topic at a future TAC meeting to cover this as we learn more in that process.

James Gall: The next bullet is on long-term or long duration storage opportunities we mentioned in the last TAC process: pumped hydro, iron oxide, hydrogen, ammonia storage. We'll have a presentation by Lori this afternoon to seek input from you, the TAC members, for the technologies we should be looking at. Are there technologies that we shouldn't be looking at? Also, if there's anybody that has information on these technologies, whether it's cost information, where we're at in the development process that would be great for you to share with the group.

James Gall: Another topic related to Named Communities, like Kelly mentioned, communities that are defined by the State of Washington as Highly Impacted or Vulnerable Populations. The ask was to determine the amount of energy efficiency that is in those areas. In our last IRP process, we did break out energy efficiency by low income. We wanted to further look at that spatially and the Named Communities. That process will be beginning shortly in determining whether or not that's something that we can do with any accuracy.

James Gall: Next bullet was on transmission access. As some of you might recall, Washington State legislature did pass a bill that requires IRPs to look at transmission. We are going to be making some changes in our modeling process to account for that. Actually, Mike will be going over that in the PLEXOS tool this afternoon. But we are also concerned about surplus energy and that tool will help us determine what is that future utilization of transmission to export excess renewable energies that we're going to be acquiring to ensure that we can meet 100% by 2045. That tool will help us manage that Action Item and then the last bullet will probably play out through the regulatory process. But that is looking at, how do we define what 100% is when we're in 2045. Does that mean that we should be planning our system as an electrical island? Does that mean that we will be allowed to buy power from others? How do we ensure that it's clean in a connected market? I don't think those will be answers we will have in the IRP, but it is an issue that needs to be addressed regionally, or at least in the State of Washington, because the implications of how you design rules for CETA will impact what our plan is. I’m going to pause there. If there's any questions. I guess not, OK.

James Gall: Just a real brief introduction of PLEXOS. I don't want to steal. We have a question [from unknown user in chat], I found when I set up an external facing Team site for the project that DES Energy is doing that non-state individuals invited to the Teams site could not access more of the site if they logged into the site via web browser rather than the Teams app on the computer. So probably the same is true for yours. So, we'll be looking into that. We hope it works. We're told it's going to work for us, so if we do run into roadblocks, we won't have to revert back to the old method, which I said, fail fast is OK, so hopefully we don't fail fast.

James Gall: Alright, so PLEXOS. Mike is going to cover a lot of PLEXOS later, but there's a few things I wanted to throw out there as you think about this, before we get to Mike's presentation. So, what is PLEXOS? It's a production cost model developed by Energy Exemplar, and its benefit, or its technology that it uses, is a mixed integer-based design which is very similar to what we use in our PRISM model, and we plan to use it for resource evaluation and market risk analysis. And what this is, when we look at each of the generating resource options, that Lori will be talking about later, is we need to determine how they're going to be dispatched and how much market value they create. Aurora does do a good job at this, looking at it from a market perspective, but as we acquire more renewables and then look at energy storage, we need to look at this from a portfolio basis and that's where PLEXOS really the strength in that tool. So, we think it's going to do a little bit better job at valuing energy storage from that portfolio. Especially with our reserve modeling. Of course, the future could create an RTO which would maybe allow for other options to model this in the future. But for now, in a control area environment, or balancing area environment. I think this technology is probably best suited for studying these resources.

James Gall: The other major change that PLEXOS brings to us, compared to using Aurora, is a more sophisticated hydro modeling technique. Aurora does a phenomenal job of dispatching hydro from a regional perspective, but when you look at it from a portfolio design, there's just constraints of the system that we can't model, and we think PLEXOS is doing a much better job with that. We'll have some presentation by Michael. We'll show that in a little bit.

James Gall: As I mentioned with transmission earlier, it's capable of modeling detailed transmission. The last couple things on here is the future that we see with the tool. One is can it replace PRISM? Or should we replace PRISM, I guess is maybe another question, but it does have a capability of doing capacity expansion for both transmission and generation. We'll be testing that in this IRP process, but will continue to use PRISM for this IRP process. And then the last point is, it theoretically can do combined natural gas and power modeling and that's something that we would definitely be curious at looking into as well. There's definitely a future for expansion between IRPs, between fuels, so there is potentially, but we are going to take this a little bit slow just to ensure that we're comfortable with the results we're getting. And also, we are a small team of folks and so it does take time to build these tools out and ensure that we're getting correct results.

James Gall: Like I mentioned earlier on the load forecast update, we have an agreement with Applied Energy Group, AEG, to do a long-term load forecast. We're actually doing this for both natural gas and electric. The idea is to ensure that we understand the implications of electrification and what we're looking at here is, if we have customers switching between natural gas and electric, we wanted to ensure that we account for the correct amount of BTU transfer between the two fuel types and then the efficiencies of those options. So, AEG is in the process of conducting a load forecast for us. It's going to be consistent with that. Our potential state, like I mentioned earlier, they will be producing three scenarios for us, a high, a low and an expected case. And we'll be seeing, I think the first iteration of that load forecast in the next two months. We'll update it again and present it to the TAC in the spring. And then with that load forecast, they can use it to determine our demand response potential and our energy efficiency potential assessments.

James Gall: I think one of the challenges we had with, say for example demand response, is what is the amount of your water heaters there will be in the future from a electrification conversion for example. And this should say, streamline our process on the customer opportunity side for what does load growth look like? What do resource options look like from demand response and energy efficiency? We're excited about this change and it should hopefully provide a better result.

James Gall: Another update on PRiSM, like I mentioned earlier, we are looking at testing PLEXOS to replace PRiSM for the next IRP in 2027. But we're going to wait on that. We were a little bit concerned about, can PLEXOS do the level of detail for energy efficiency that we do in PRISM. Can it run fast enough to run the scenarios that we need in this IRP process? What is it going to take the build these portfolios out? We like PRiSM because it's nimble, it's very transparent, but is it the best technology to help us on this path? That is yet to be determined and one of the concerns I have with using PLEXOS to do portfolio modeling is that transparency, where PRiSM is, we can post that on our website. You can look at all the assumptions and PLEXOS requires you to buy a tool to look at those results. That's something we'll be considering, and we would like input from the TAC as well through this IRP process as we test it, and before we make a decision in the 2027 IRP. I think it would be helpful to hear your comments on what technology might be best suited for that next IRP.

James Gall: Another thing we are testing in PRISM is co-optimizing the natural gas system and electric expansion. What I mean by this is instead of having a separate IRP that looks at figuring out which resources are needed for the electric demand and the gas demand, we bring that all in one tool and the model can choose what's the best way to serve that demand. For example, if there is a heating demand, is it best suited to be served by electric or natural gas from a least cost basis.

Lori Hermanson: Got a question James.

James Gall: All right, I'll pause there. Fred, go ahead.

Fred Heutte: Hey there everybody. Fred Heutte, Northwest Energy Coalition. Good morning. Just a very quick comment on PLEXOS. I think you may very well know that PacifiCorp has been using that for a couple years now. And I hope you've been chatting with them about their experience. They had a lot of trouble. They did, in my personal opinion, not do a long enough transition approach. They did some. It wasn't like they just dived in. Throughout the early they were using system optimizer before that, not like they just completely jumped. But I don't think that they did enough of the transition like you're doing. It's very powerful. It's a beast. From what I understand, I've not seen a detailed run through. You know how it operates, but where they did do that was system optimizer.

James Gall: All right.

Fred Heutte: Using PLEXOS as your primary model is the right way to do it, and specifically on energy efficiency. I would concur about the potential there, where PLEXOS may have some advantages. You could talk to the PAC IRP team, Randy Baker and everybody there. They've done some very interesting things with PLEXOS too, and in some ways kind of overkill how complicated they've gotten with their EE analysis, but it's really robust. Hopefully you'll be able to figure this thing out and looking forward to how it all looks as you go through that.

James Gall: Hey Fred, I asked about this transparency issue. Are you comfortable with PLEXOS as a tool, is that transparent enough or would you like our transparency of PRISM?

Fred Heutte: You know honestly, and I follow modeling pretty closely, but I can't say that I'm a modeler or I know a lot about software, I'm not a practicing modeler. So, I think there may be a participants, stakeholders, whatever in the IRP process who might be interested in taking a look. Yes. You know, I think one of the really positive things about Avista’s approach to the IRP is you do make everything as available as possible. You know the models, the data, et cetera. I think we have a tradeoff here. PLEXOS is a really big beast. I don't know what the licensing fees are, but you know they're pretty high. I think the key thing will be to you know that as long as you provide the kind of transparency into your methods and the outputs, the UTC staff and maybe some stakeholders that have really serious modeling capabilities of their own might be interested in taking a look at some of the results. But practically speaking, I think as long as we're sure that you're running things as you say, and we have a good interest in looking at specific details, outputs you're able to provide that. I don't really see a big problem.

James Gall: OK. Thanks, Fred. Any other comments before I continue on? Alright, I have my last slide and I'm hoping this last slide will get some feedback. I'm going out on a limb here and you might remember if you've been part of our TAC process, I think the last meeting in our 2023 RFP process, we talked a lot about resiliency and how do we include resiliency in IRPs is a challenge across the entire industry because most resiliency aspects are at the feeder level. And I think that's appropriate. But IRPs are typically at the generation level, somewhat transmission level and but there are things that are resiliency based that we should be looking at. I think about this as a resource diversification and John and I were spit balling a month ago about how do we deal with resiliency. And we came up with a methodology, the quantify of diversification, some of those that are finance nerds may have heard of the Herfindahl Hirschman Index. But we thought, is this a way to measure resiliency? And you know, maybe this ends up as a Customer Benefit Indicator, I don't know. But what I think we can do with this concept is look at diversification, not just the fuel types, but fuel locations. It's just the generator locations.

James Gall: What I've done on the right is come up with three different methods I had time for looking at diversification. One is the amount of generator units we have. The second one is facilities. Noxon has five units, but it is 1 plant, so from a risk point of view we've spread that risk of generation failure out across 5 units, which is great. But you're still at one site, so if there was an event, whether it was some type of catastrophe or a substation outage, you still have one facility and you can lose the whole system. One thing on the substation is what we've done there to prevent that risk is put two substations there, that helps, but look at how spread out is our number of facilities, not just the number of units and then another item we looked at is fuel supply. So where does our fuel come from? What I mean by that is, like a natural gas plant, the fuel is coming from the GTN pipeline for example, and then you compare that to hydro. We have the Clark Fork River system, we have a Spokane River system and we have a Mid-Columbia River system and then we have different watersheds. We looked at where is the fuel supply from for our system. Where do those come from?

James Gall: The Herfindahl Hirschman Index looks at market share, or percentage of the population, and it comes up with a measurement of competitiveness and the higher the number that you come up with indicates less diversification of your resources. So, the academics came up with, if you have a score that's less than 1,500, you're very competitive and very diversified. For the two metrics we looked at, generating units and facilities, we are very diversified. We're well under that 1,500 and if you're between 1,500 and 2,500, you're in a moderate diversification level. And then if you're over 2,500, you're too concentrated in a particular area. On fuel supply, you see we're really close to that 2,500 and the question is from an IRP perspective and a generating perspective, should we be looking at resources that have other fuel supplies. That might be something we look at as an indicator of a resource choice for the next IRP. Should we keep the portfolio under 2,500 for example, for the different metrics?

James Gall: These are three metrics I threw out there. There's other metrics we could look at, such as transmission system, which path the resource is on. We could look at wildfire risk areas, do we have plants that are in wildfire areas and trying to ensure they are minimized or in different areas. Another one that we looked at is low diversity, and that's not necessarily the generation side, but we could do this analysis on our loads and maybe look at are their risks in different load types that are especially available now that we're looking at end use load forecasting. But I'm just curious if what others have seen on how do we deal with resiliency in IRPs, does this this seem appropriate? No, don't like it, or something else? I'm just curious of any feedback you have and if you want to think about it, it's OK you can email us later, but I'll pause. I see a hand go up. Heather, go ahead.

Heather Moline (UTC): Hi. Heather Moline, UTC staff. This is interesting. I've never heard of Herfindahl Hirschman. Thank you for that overview. Food for thought. Again, this is not Staff's opinion or the Commission's opinion, but you just asked for feedback. So, I wanted to put it out in the space. Maybe it does make more sense for resiliency to be quantified and incorporated into something like the CEIP as opposed to IRP, because CEIP tends to be a little more about local customer benefit and a little less about long range, large resources. That's just one thought. I would like feedback on the second thought, slash question, is to what degree have you all looked into the resources from the national labs and Energy Trust of Oregon on resilience quantification? And incorporation into resource considerations.

James Gall: Can you tell me a little bit more about that last statement about the national labs?

Heather Moline (UTC): Yeah. The Lawrence Berkeley National Lab and Pacific Northwest National Laboratory. This is one of the main questions that they've been doing research on for the last three years is, you can't include zero as a benefit or cost of resiliency because there is a benefit to resiliency. So, how do you put that into models? And I haven't seen any studies in the last year, but there may be some. I just wondered if that was research you all were doing.

James Gall: I guess we have not looked at those. We will. One thing that I see this related to is, because you've talked about values and we tried to quantify non-energy impacts in the last IRP and where I'm going with this is if the studies, if they're showing values for different resources, you could put that value in our optimization tool. But we'll look into that. I appreciate that. That's why we're doing so.

Anette Brandon: James, can I comment on this? This is Annette.

James Gall: Go ahead.

Anette Brandon: Hi, this is Annette Brandon, I'm in wholesale marketing and Heather, I have actually been following that PNNL resiliency modeling how to value as part of our equitable business planning initiative. James and I did look at it very briefly, although I'm not sure I pointed out to him what exactly that meant, but I have been following that pretty closely as we start to implement this overall project and so will be coordinating with that as we go forward.

James Gall: Alright. Well, it's one at least we have one idea to look into. Are there any other thoughts, comments.

Heather Moline (UTC): This is Heather again. That's great to know. And just so you folks know, you are not the only people asking this question. So, as we become aware of more things with the other companies, we'll be in touch.

James Gall: OK, appreciate it. The CEIP is definitely an avenue for, there'll be solutions or ideas to solve resiliency there. There could be an avenue of how do we define a Customer Benefit Indicator for resiliency that will be in that process and maybe one of these HHIs is one of those. I do see it as a place for generator level resiliency and the relation there is I see what's going on and say, Texas, what was that four years ago? I can't remember, but having facilities that are capable of running and in cold weather for example, but if this is an area that's I'd say it's come up, but I'd say no one cracked that nut yet.

James Gall: I don't think we have either, but we're going to at least try to explore this, and we'll look at the national labs work and we'll continue maybe to look at this as an option and maybe circle back with the TAC. But, if you have any ideas, let us know afterward or throw them in the chat.

James Gall: Alright, so what's next on the agenda is it a break. Can't remember, I don't know. Let's check here. PLEXOS is next. Then we'll go to break. Unless we need a break now. But we're supposed to take a break at 10:45, so we do have time. I'll bring up the PLEXOS slide deck and if you can, we can do that. Bear with us one second as we transition. Alright, I think it's there and Mike's ready to go, OK.

<u>PLEXOS Overview and Back Cast Analysis, Mike Hermanson</u>

Mike Hermanson: My name is Mike Hermanson. I'm a Senior Power Supply Analyst here at Avista and I'm going to be talking about how we are integrating PLEXOS into that IRP, analytical modeling for the 2025 IRP and also the testing that we've done to determine how well we are able to represent our system within PLEXOS. Just a little background here. Power supply modeling is integral to the IRP process. It's the analytical framework to determine the long run economic and operational performance of alternative resource portfolios. So, as you go into the future, what different resources solve your different various constraints in the most economic fashion. Our existing system, and potential additions to the systems, are subject to many constraints and uncertainties. For example, the timing of hydro generation, gas, power price movements, government regulations, and analytical models provide the framework to put all of those very complex pieces together that don't always move in the same way and then it allows us to assess the impacts these variables have on our system.

Mike Hermanson: And then, as we go into the future potential additions to meet the load obligations that we see coming in 2045 for the 2023 IRP. We used Aurora forecast electric prices, and over the planning horizon. We also used Aurora to dispatch the resources to meet load. That dispatch was then used in the Avista developed PRiSM model to select new resources to meet the projected load. For the 2025 IRP, we are taking a different approach. We're developing an electric price forecast in Aurora and then we will be using PLEXOS for dispatch and that dispatch will be used in PRISM to determine the resource selection, but concurrently with using PRISM. We plan to be testing the resource selection functionality with PLEXOS.

Mike Hermanson: Just a little bit of background on PLEXOS. It's from Energy Exemplar, who also makes Aurora. It's a widely used model for electric market analysis, power system optimization. It provides market simulation. It can analyze and simulate electricity markets considering various factors such as supply and demand, pricing market rules.

This provides insight into the market dynamics and in adding energy trading optimization, which is a very important component of this considering different resource options going into the future. PLEXOS also provides for power system optimization. There's a multitude of constraints that you can put in there such as outages, maintenance, market prices, hydro variability, emissions targets. Hydro variability is an important one for our system. Being able to test different variability, and actually the variability more at a more granular time step than we were able to do in Aurora, allows for integration of renewable energy and looking at the impacts of these variable generation on the power grid and how that drives our need for extra reserves.

Mike Hermanson: PLEXOS also has robust transmission planning. It's forced transmission planning, expansion studies, allowing the inclusion of transmission upgrade costs associated with potential resource additions. Certain additions of resources such as solar are only going to make sense in certain areas, but do you actually have the transmission there to deliver that to the grid and to actually be utilized in the near term.

Mike Hermanson: Hydro modeling is where we see the biggest change over dispatch in Aurora. PLEXOS models hydro as water coming into a reservoir and then running through generators. It really represents how it is physically used, the physical movement of water and the maintenance of reservoirs. This is in contrast to how it was utilized in Aurora, where it's a bucket of megawatts and you can put some constraints on it. But it really does not mimic how we operate our hydro system, the flexibility that's inherent in it and also the operational constraints that are inherent.

Mike Hermanson: This slide just shows the general schematic how the model operates. On the left you can see we provided an hourly native load to be met by Avista, owned and contracted generation, market purchases and sales. The hourly load is generated outside of PLEXOS and as James mentioned, for the 2025 IRP we have contracted with AEG to assist us in developing an end use load forecast. That end use load forecast is also outside of PLEXOS will be able to do a lot more scenario analysis, especially as it relates to electrification and EV penetration as you go out into the future. All of the estimates of a government program in place or contemplated, are those going to be coming fruition and if they do, what kind of impact are they going to have on our load? That'll happen outside of PLEXOS.

Mike Hermanson: The next section is the Avista owned and contracted generation. The generation is optimized economically against the electric price forecast. You're trying to get the least cost energy, but there's many constraints that are inherent in these generating resources. PLEXOS allows for regularly scheduled maintenance and forced outages can be done in a statistical manner. The timing and quantity of hydro, including changes over the planning horizon we can bring to play, we do have for example, our hydro forecast bringing in climate change and the shift of water to earlier in the year as opposed to the current or what we've seen in the more recent past where we would get water in June and July. Now we're predicting seeing more in February, March, earlier melts. Let us know snowpack, so we have to bring that into the PLEXOS modeling. We also have in this this middle bucket here we're looking at and have the provision of ancillary services. The variable nature of wind and solar resources, and then we could also look at the impact of fuel costs on running our natural gas resources and in the future, looking at all alternate fuels such as ammonia and hydrogen.

Mike Hermanson: The next section that I look at when we're breaking apart PLEXOS is the market purchases and sales. All of the costs and constraints of our system are balanced against the markets that are available to us, such as the Mid C, which is the primary market that we are integrated with. But we also have some others in the northeast part of our system and COB, the model optimizes and solves at an hourly time step on the native load and then any contractual obligations, sales that were done, and these are met by generation and market purchases and sales every hour. It's a very robust system that you can bring in any multitude of constraints that are affecting your system. The granularity doesn't solve it. Actually, you can get much more granularity solving that at the five-minute time step. We have done some testing at the five-minute time step to look at EIM. Those all of course take quite a bit longer, but it is possible.

Mike Hermanson: This slide shows how our transmission system is represented in PLEXOS and it's a little busy, so just bear with me. Each of the light bulbs on this graphic represents a load center, and each of the green dollar sign icons represents a market where we can either sell or purchase power at, and then each of our generation sources is connected at the appropriate service point. Each of these lines is assigned a maximum flow that can occur on that line, and also power that goes over Avista owned lines which are shown in blue. I don't know if you can see the difference between the blue, kind of looks black, but the ones shown in blue do not incur a wheeling charge, while the power that moves over the yellow lines do incur a wheeling charge, which is dependent on the owner of the line. All of that is input into the PLEXOS system and then it makes decisions on which ways to move power to load centers based on the most economic pathway. This is an upgrade I would say from our previous IRP where we had a much more simplified representation of our transmission system and it's in reaction to the addition by the legislature into the IRP rules. I guess it's not by the legislature, but by the UTC to add into evaluating transmission constraints into your IRP considerations.

Lori Hermanson: We have a question from Yao. Do the cost of market purchases and revenue of market sales include wheeling costs and revenues?

Mike Hermanson: Yes. Essentially that'll be a hurdle rate to buy from the market if you're having to use transmission, so it'll be netted out.

Question from Room: How does the model build losses?

Mike Hermanson: If you got that, you're asking how does the model deal with losses, you can actually put losses, line losses into each one of the lines. We haven't done that just yet. We have right now the sophistication of the line representation has a three-stage maximum flow of megawatts can go across the line depending on the season, because it's temperature dependent. But we could also introduce line losses if we choose.

James Gall: But one thing to note, online losses is when we look at load or native load, you'll see that in any of the data files we provide and how our accounting system works is that load includes the distribution and transmission losses on our system. It does not include third party system losses, so I think where we might end up, like Mike said, is we could put in the transmission losses on the lines that are not Avista's, but on the ones that are shown in blue or black, we'd likely not include those because they're embedded in our load forecast.

Mike Hermanson: This slide shows the PLEXOS interface. Just to see that real life software, the system that we use is built from components that are shown on the left pane. If you look at the main screen, we have the left pane, and it has all the system components. You have all the different generators, lines, markets and then you move into the middle pane, and you can see that all of these components are then connected and connected in different ways. Fuel is connected to a generator, is connected to a line, and then we can design properties to all of those, and then the bolt section of that first window is all of the properties that you add into each of these components, and it varies by the different generator you have. For example, natural gas generators have a lot of information about heat rate, whereas the reservoir components have a lot of information about hydro flow, how large the reservoir is, what min and max levels can occur in that reservoir, what are the ramp rates for example. And then PLEXOS has a pretty robust system to display results.

Mike Hermanson: This is just an example of the generation over a year at Noxon Rapids, one of our hydro facilities. You can look at all sorts of different resolutions. It's very integrated with Excel. If you're an Excel user, like most people are, you can export these results very easily to Excel and then do analysis on that also.

Mike Hermanson: I don't think I need to tell anybody on this call that representing these energy systems is very complex and representing energy production, market exchanges and transmission in a model has many challenges. With these complex models, it's always a balance between how much complexity is introduced versus runtime for the model. Currently, our 20-year run takes between six and seven hours to do one iteration of it. We plan to run the model with stochastic inputs to capture the uncertainty in our model inputs we would be using. Selection of water years is different than just the one prediction to see what the sensitivity our system has for different water years. In 2021, I believe we ran 500 model runs to capture this stochastic nature and capture the uncertainty in all of these. Then 2023, we're at 300 model runs at six to seven hours a model run, and 300 runs gets quite lengthy, but there's different approaches to reduce the model runtime to kind of reel that in. We also use multiple machines and so we believe it's a doable challenge, but it will be a challenge. Looks like we had a question there. Heather, if you still had one.

Heather Moline (UTC): No, I was doing that math in my head, 6 to 7 hours times 500. You answered the question. Thanks.

James Gall: We do have 25 machines to spread that around, so it won't be that long of a math problem, but it'll be a long math problem.

Mike Hermanson: Another challenge with a model. We have perfect foresight. For example, electric prices are projected for the entire planning horizon. That is different than what we obviously have in the real world. Another challenge is this system has significant hydro resources with storage components. It's difficult to capture the myriad of constraints. We have licensed constraints, but sometimes the system is constrained by uncertainty or by other considerations on reservoirs, especially reservoirs that have recreation, they have homes that are built on the reservoir. That is capturing how perfect foresight is going to dispatch a hydro reservoir versus how it is dispatched in real life is a challenge and that's one of the things we've been working on quite a bit this last six months. It's difficult to capture the dynamics of trades that happen at different time steps. For the most part, we have power ahead trading that's happening at the market. So, they're looking at what generation we have available, the price of that generation, and then checking that against the market. Now we have day ahead, hour ahead and even EIM trading that is difficult to capture.

Mike Hermanson: Integrating forecast error into modeling, that's another challenge. We're operating our system with a forecast of what's going to occur. What's the forecast of the load? What's the forecast of the water? How much reservoir? You need to have for that, the runoff, when’s the runoff going to happen. When we just input the flows for the whole year, you can go in and solve, and it knows what's coming. That makes it a challenge to integrate and try and mimic how we would dispatch our system with imperfect information versus how PLEXOS dispatches our system with perfect foresight. As a result of all those challenges, the model will always have a lower production cost than actual. It'll be able to be more efficient than we would be able to just run our system. Our production cost is obviously always higher and so trying to get a sense of what that magnitude is really, the effort is to look and see what we can quantify what that forecast, and uncertainty, adds to the production cost to deliver energy.

Mike Hermanson: We started with PLEXOS back in January and our first approach was to see how close we could get PLEXOS to dispatch against an actual year where we had actual data. This is going to verify how we built our model. We built the model with the inputs to all of our hydro units, all of our generation, natural gas generation, and everything. And we used 2021 data including the hourly load, hydro inflows, run of river generation, the Mid C price, daily gas prices, the renewable generation actually scheduled, forced outages, and the reserves that we hold including the frequency response reserve, non-spin regulation up and down, and the reserves we hold for very little energy resources for when solar.

James Gall: We’ve got a question.

Lori Hermanson: Yao’s question was, isn't all the input data actual data in 2021.

Mike Hermanson: Yes, all of this data was actual data from 2021 and then we used that data with the system that we constructed. We constructed the generators, the transmission, and built the model, and then put 2021 data into it. And then the question is, how close can you get? Now we have the actual dispatch, and we're going to have the model dispatch, and how close can you actually get? Hopefully, if you're getting close, that means you constructed those components of your system correctly and are accurately representing them.

Mike Hermanson: This shows the actual 2021 generation, then the generation from the PLEXOS run, and then the difference. The units shown are the ones that can be dispatched and they're not close, not include the must run facilities. So, when we get solar generation, we just take that generation and you run that generation. It's not dispatched. That might be dispatched if you had a battery, and similarly our run of river projects, we just took the actual generation and put that into the model. So, what you're looking at are ones where choices could be made about when generation could occur, and also choices to be made or not. But outside influences could happen, such as hydro coming in differently or payments to be happening, forced outages.

Mike Hermanson: What we found out was the total actual generation was 1,130 average megawatts, while the model generation was 1,122 with relative percent difference 0.18%. It dispatched on an annual basis very closely and we also conducted an evaluation of the mark to market production costs, subtracting fuel costs and found that there was a 0.96% difference between what PLEXOS system cost would have been versus the dispatch generation. If we have the actual dispatch, did a mark to market, and then we looked at our actual total expenditures and we've found the difference between 2.96%. As mentioned in the previous slide, the model production cost was less than the actual production cost.

Mike Hermanson: The next series of slides show the hourly dispatch for selected generators. Blue shows the actual generation and orange shows the model generation. Noxon Rapids is shown on the left and Cabinet Gorge is shown on the right. There are differences between the model and the actual, but generally follow the same pattern. Since the model has perfect foresight for water supply and market prices, it's more likely to move to the maximum generation and then back off to minimum generation then the projects are actually operated. They just don't necessarily operate that way where you have a lot of power to measure reactions to it. Prices and the model production cost was less and the actual revenue from the actual generation was slightly greater than the model generation, I should say had more revenue than the actual generation, but it was fairly close. As you can see, the difference between the two just on average generation of PLEXOS being 178.5 average megawatts versus an actual generation of 179.8 and the things we were checking on was how we have our generators set up in PLEXOS. How is that water actually taken and turned into energy? Do we have all those parameters set up correctly? This is a check on that.

Mike Hermanson: As you can see, over on the right-hand side is the Cabinet hourly generation. You can see over on the September, October months, there were units out. We're able to take those units out in both instances and be able to capture that again. You still see a little bit more opportunistic movement in backing on and off generation in the model. But we did some adjustments to our ramping rates to try and address that. Now, we'll see that when we look at the reservoir.

Mike Hermanson: The next two graphs show Long Lake and Little Falls. An interesting piece here is that the PLEXOS generation in the spring is again using knowledge of water, prices, and is moving from maximum to minimum on occasion when the actual operation, is not doing that and that's to some degree you don't know when the water is going to come off and have them fill a reservoir. PLEXOS did because it had the whole year in front of it. Operators are making decisions about when to keep the reservoir full and not full. And you'll also see that dip there in February and March, and that's the annual drawdown in Long Lake and that really lowers the head. Once you lowered the head, you lowered the amount of generating capacity from each of the units. We're able to build that into the system. Again, these look very similar, Little Falls has a very small reservoir and in essence is run as a run of river at Long Lake. But again, the annual amounts are very close, and we are able to get the shapes we feel to be very representative of the actual.

Mike Hermanson: The next series of graphs show the total generation facilities from Chelan, Douglas, and Grant PUD. That's the Mid-Columbia hourly generation comparison. Again, it's able to follow the general patterns that occurred at those facilities. We have a contracted portion of generation at each one of these facilities and we have the ability to dispatch the plants within constraints that are provided by the PUD. The graph on the right is for Coyote Springs 2, which is a natural gas combined cycle facility. The actual values move, in the blue. They move more than the model values and that is because generation is dependent on temperature and so you have daily temperature movements in an effort to get more model efficiency and be able to keep the model running as quickly as possible, we ended up using monthly values and it's a very good approximation.

Mike Hermanson: This next one shows Lancaster. It's a contracted combined cycle facility, similar to Coyote Springs 2, and the actual value shows more variance than the model. Rathdrum is on the right-hand side and it's a simple cycle peaking facility. It has the largest percent difference between the model and actual values, and that is just due to the different ways that the model was able to address some of the peaking mode that came in, and so it didn't have to rely as much on this peaking facility to meet below.

Mike Hermanson: These four charts show the reservoir storage level throughout 2021 for each of the storage projects. On the left is that reservoir elevation, the forebay elevation, and across the horizontal axis is the months. You can see in the Noxon graph. You can see one of the changes that we made to. To kind of back off, PLEXOS' inclination to jerk the reservoir around, so to speak, which just operationally does not happen. We limited the hourly ramp rate and so that tightened up the reservoir movement as you can see in the springtime months. We were moving that around quite a bit more in actual operations, but to match the dispatch. We constrain the hourly ramping and that tightened that up a little bit.

Mike Hermanson: Looking at Cabinet Gorge, the orange is the model value. You can see how it likes to move hitting those hours where the market values are high. It's still within the range of what we actually see, but the reservoir does not move around quite as much as PLEXOS would like to do it. Or does do it in Cabinet over many iterations of trying different ways of time, tying the dispatch of these hydro units, this combination of using this hourly ramp rate at the reservoir at Noxon ended up providing the best match.

Mike Hermanson: If you look at the graph on the right-hand side. Those are for Long Lake and Little Falls. The bottom shows Long Lake and there's a drawdown that happens in springtime months, and then a significant increase, and then it runs within a fairly narrow band of reservoir heights. It's not doing big reservoir moves to meet price and that's a constraint that was put in to match the actuals. I guess this whole effort was really to get hydro to be close to the way we operate it, so that the rest of our system can balance against that and get a much more accurate picture of what the dispatch looks like and the production cost.

Mike Hermanson: You're probably wondering on Little Falls. Little Falls operates within a really tight band. You can see that PLEXOS is operating it within quarter of the foot. Those are in half foot increments and that graph in actuality operates slightly different with a little more volatility, but not much more. And also, halfway through the year before my elevation data, something happened with it in 2021. So, it only had a half year's worth of data.

Mike Hermanson: These last slide shows the model value for model versus actual values for the Mid-C reservoirs. And as I said, this isn't the sum total of how the Mid-C reservoirs are acting. This is how the portion that Avista controls is moving, it's not moving in total unison, but the magnitude and the variance. This is fairly similar. We're able to match the timing and the actual output for this Mid-C system fairly well. When we came to that end of all of these exercises, we came to the conclusion because PLEXOS we were just trying to test it out and figure out how well is this going to work for our system? We've been using Aurora for a long time, and I think we came to the conclusion that we can flex. Those can be used for the dispatch and match with and incorporate all of the constraints that we want. There's still more that we want to build it into it, and so our next steps are that. Building this into our IRP modeling.

Mike Hermanson: This is just looking at one year, whereas we'll be building out the full 20-year IRP and doing adding additional resources and doing that iterative process of looking at what we can generate out of PLEXOS versus what we can generate out of PRiSM and going through that process. But I'm not sure if there's any other questions as a lot of information all at once.

Lori Hermanson: There's no unanswered questions in the chat. There were several people that gave us additional information on resiliency, which we will follow up on.

James Gall: Alright, well, there's no questions for Mike. I appreciate the presentation. A lot of work has gone into PLEXOS and like I said, we see a bright future for it and the IRPs to come. We are little under 1/2 hour ahead of schedule, which is great, which means we can take a break. I think we could probably get back and finish early, so let's take a break until 10:30. Does that work for everybody? And then we'll get started on the available resource options with Lori at 10:30 and then finish up with the Work Plan and then adjourn, hopefully by 11:30, we can get done early, so we'll go on mute and see you back here at 10:30.

<u>Available Resource Options Discussion, Lori Hermanson</u>

John Lyons: Well, welcome back everyone. Hopefully you got a chance to get up and stretch a little bit as we get towards the end of our first TAC meeting. Lori is going to be up first and talk about generation resource options and then after that, I'll finish up with the Work Plan.

James Gall: We're thinking we'll probably be out about 1/2 an hour early today and before Lori gets started, this is an area where we like to get TAC feedback, so don't be shy. Use the chat. Lori will be monitoring the chat as she's to presenting and they go away. Lori.

Lori Hermanson: Good morning. I'm Lori Hermanson and I'm going to cover the resource options that we included in the last IRP for review. We would like your input as to whether or not you think that we should maybe not include ones that we did include, or maybe we've missed some. We'll talk about that as we go through, but that's basically where we're looking for feedback. If you want to go to the next slide, I'll start with the natural gas turbine options. We tried to model one of every different category, peakers and base load, and then the types of peakers. For peakers, we modeled a simple cycle combustion turbine frame type engine. The model is 2 units totaling 180 megawatts for the reciprocating engines. We modeled 10 units totaling 185 megawatts for baseload engines. We modeled a combined cycle combustion turbine 1x1 with duct fire, and that totals about 312 megawatts for these combinations. For these types of turbines, we also looked at different fuel types and not just natural gas – renewable natural gas, hydrogen in the form of ammonia, and synthetic natural gas. For these natural gas turbines, we considered them as Avista owned resources that would have a 30-year average measure life based on the policies that we're seeing in Washington and Idaho. We're going to continue to look at non-natural gas fueled options for Washington. But in Idaho will continue to look at all fuel types, and then we'll also continue to model and evaluate, or evaluate and model, potential upgrades of our existing facilities. Next slide please.

Lori Hermanson: We looked at renewable resources such as wind and solar. On the solar resources, we looked at varying sizes, applications, and storage options. We looked at a residential 6 kW unit as our resource option as well as a commercial one MW option. We looked at a 5 MW resource that was a fixed array. All of those, we modeled them with and without battery options. We also looked at single array or single access tracking arrays of varying sizes from 50 to 100 megawatts and varying sizes of storage duration. The ones that have lesser storage, those are used for integration purposes. If it's a longer duration storage, the model would pick them because they're needed for load shaping. For wind options, we looked at 100 MW options for all of them starting with on-system and off-system wind with the difference between those being the cost of transmission. Off-system, we looked at Montana wind because that was of interest for our stakeholders. We also looked at offshore wind, which was 100 megawatts of a larger share project of about 1,000 megawatts. For all of these, they are proxy sizes and Pacific Northwest locations. What the model does is it would look at these minimum sizes of say for wind at 100 megawatts, but it might end up selecting up to 400 or something at whatever makes sense based on the needs of our system. Again, we put them in as a minimum size and then it picks accordingly based on those minimum increments. So next slide please.

Lori Hermanson: We looked at other clean resource options such as geothermal. This would be a PPA of about 20 megawatts and it's an off-system resource because there's none right here in our service territory, so it would incur or include transmission costs. We looked at biomass, a generic biomass resource option, an example of that would be an upgrade or an additional unit at Kettle Falls or something else in the area. Something around that size of 58 megawatts. We also modeled a nuclear PPA as an option, it was 100 MW option, which is just a share of a larger off system resource and that's a mid-sized nuclear facility. And we also looked at a 25 MW fuel cell. Next slide.

Lori Hermanson: For storage technologies, we looked at more sizing and storage duration combinations and types of storage technologies than we had in the past IRP. Lithium ion, being one of the larger categories. We assumed a round trip efficiency of 86% of 15-year average operating life for those resources. We assume that we're the owner of these resources. We modeled various sizes of distribution and transmission level ranging from 5 megawatts to 25 megawatts. And again, the storage duration varied anywhere from 4 hours to 16 hours. We looked at other storage options such as vanadium flow, zinc bromide, liquid air, and iron oxide. I believe of all of those, the only one that was selected was iron oxide. Something that we're considering, and we'd like feedback on this, is maybe not modeling all of those, maybe just modeling iron oxide and lithium ion. Those were the ones that were selected this last time, but again, based on feedback from the groups. Also, based on reading and research in the industry, the lithium ion and iron oxide seem to be moving ahead, whereas those others don't see as much progress. We also modeled a few different pump hydro options, and these are again varying durations from 10 hours to 24 hours and increments in between. It would be basically a share of a larger project anywhere from 1,000 to 2,400 MW hours.

Lori Hermanson: Next slide, some additional things that were continuing to research that you're all probably hearing about these in the industry as well. Carbon capture and storage. This is where you capture the CO2 from generating facilities and then store them into underground geological formations. The only thing with this is there aren't really any of these geological formations in our service territory. We continue to follow the literature on those. There's been a lot of information out there on fusion reaction. That's where they have a nuclear reaction that creates a lot of heat or energy problem with this one. There aren't really any real costs out there. We haven't come across cost associated with that type of project. There are other battery options like organic, solid, flow, energy storage that's a proprietary non-flammable mixture of solid and water-based electrolytes. That's using renewable energy to heat carbon or graphite blocks too really high levels about 2,200 degrees Fahrenheit stored within insulated containers and then using that heat on demand as it's needed. I believe we've modeled some. We've included this in some of our demand response modeling done by AEG. As far as the molten salt heat storage, that's another one where you can use concentrated solar to direct it to a centralized receiver and raise the temperature really high to heat the salt medium and again, dispatch that as the heat is needed through a heat exchanger to produce steam. But there aren't really any steam turbines in our in our service territory where that could be applied.

Lori Hermanson: Those are some of the things that we've continued to follow and are researching. We'd love to hear information or feedback on other options that you might be aware of. As far as new hydro, we're always looking at possible expansions within our service territory such as our own units like Long Lake or Cabinet Gorge adding an additional unit at Post Falls. We recently obtained a contract with Columbia Basin Hydro and there might be some discussion about extending their irrigation canals. But then there's some consideration as to whether or not that would apply for CETA as new hydro or not. And then we also continue to evaluate new hydro like in the last RFP. We acquired additional slices of Chelan, and we continue to look at those. We have a Douglas [PUD] contract that expires in 2028, so the potential of expanding or extending something like or other things that might become available through BPA. That's everything in a nutshell. What was modeled and some potential considerations of things that we may model less of, for example on the storage or potential new technologies that are out there. We'd basically like to open this up for discussion with the group and see if there's any additional information you'd like to see more of, or less of, or new technologies that you're interested in that you think we should be modeling.

James Gall: If you need more time, don't be shy to email us afterward or enter something into the chat. What we're trying to do is, we have a limited amount of time to research technologies. What we're seeing in RFPs, we followed the Power Council, but we want to make sure we're not missing something that's in development now. I'd say that the one technology on here that we mentioned in passing is nuclear. There's been a lot of talk about small modular nuclear. I think we've taken the approach on that is to just keep it as a nuclear PPA option. That could be small modular. It could be something else. I'd say it's the one technology not talked about here but is definitely worth evaluating. These are going to be challenges that we have to face because the CETA goal of 2045 to be 100% renewable or clean energy requires technology sources that are not common today. We have to figure out long duration storage. Hydrogen-based fuels is what we found in the last IRP, along with iron oxide storage, was a potential pathway. But, as you do IRPs every two years and we need to evaluate if there are other pathways, because the IRPs before the 2023 did not even contemplate either of those technologies. Hoping that you know something comes around, but if you see something that's on the horizon, you see a journal article, just feel free to send it to us. We do want to ensure that whatever technologies we put in the IRP are commercially feasible. They don't necessarily have to be in development today and viable off the shelf, but they have to be something that's feasible and likely to be available in the time horizon. Fusion, for example, is maybe one of those resources, maybe it will, but it's not quite there yet as a proven technology. So that would be the one, for example, that we might not want to include. That's why we do IRPs every two years, and it might be available.

John Lyons: We also can add discussions on the new technology even if they're basically so far out of the realm of costs that they don't get modeled. We can still include them in the IRP as a discussion. We can start seeing where those would fit in and maybe even do some tipping point analysis to decide where that technology would have to be. We've done that in the past with nuclear where the thought was, we would not model it because it was too expensive, but we modeled how much lower the cost would need to get before we could implement it. That might be a good way to look at some of the new technologies. Also, we have opted not to as some other utilities model, we want to use a resource that looks like this, but they haven't identified it, and we've opted to stick with resources that are known and identifiable.

James Gall: Alright, I still don't see any comments, so I think we'll leave that one there for future discussion and we'll plan with these set of resources. We'll develop costs and other assumptions and there was a spreadsheet that you may recall from the last TAC process that went through our assumptions for each resource and a forecast of those costs. We'll work to update that spreadsheet with these resources and share that with the TAC when it's available. As Lori mentioned, there were a couple of resources that we were thinking about removing on energy storage. I'll go back to those real quick. They were not selected in the plans, and I wouldn't say development is stopped on these, but we're not seeing a lot of uptake in those resources in the energy space. But I just wanted to know if there's any objections to removing those. We're not going to yet, but just wanted to make an opportunity to voice any concerns about removing anything from the list, before we do that.

John Lyons: We've seen a real decrease in the number of the flow batteries that are showing up around the country, being bid in, and actually being done. Yao has a question, why did the model not select the storage?

James Gall: So, the ones that are in red, it's really a cost in round trip efficiency. There are you know, two trade-offs of storage. Either you are going to have a low round trip efficiency, you got to be very low cost. And if you're going to have a high range efficiency, there's likely a higher cost. And in these cases, there was better technologies for the cost or the efficiency for these not to be picked, I definitely think we need to keep following them. With moving to PLEXOS, there is a limited amount of studies we can do and I don't want to burden that model on the first time around with technologies that are probably not going to show up.

John Lyons: The big issue we've seen with the flow batteries and the liquid air is the constantly heavy pumps running. So, you have this this parasitic load that's going on all the time, whereas a lithium-ion battery, you don't think about. If you've got a power tool that you charge the battery up last summer and then you pop it in this next year, and it works just fine. On a flow battery, you would be out of power in not that long of a period of time because they are always running.

James Gall: OK, so let's switch to the Work Plan and then we'll wrap things up. Thank you, Lori. Bear with me one second while I find it. There it is.

John Lyons: You're building suspense. You know the excitement of the Work Plan. They just excited that we're getting close to finishing right now. We're being efficient alright. TAC meeting efficiency, that could be an Action Item.

James Gall: All right, John. Alright.

Work Plan, John Lyons

John Lyons: So, on the Work Plan, you would have seen that sent out with the draft slides. Go to the next one here. The Work Plan, as we talked about earlier, we do an IRP every two years – full IRP in Washington every four and a Progress Report in between. The Work Plan shows what the process is going to be and the major milestones, those key events that are going to be done. It starts with an overview discussion. This is going to look very similar to past Work Plans. There's the TAC meetings and the major topics on the meetings. We try to stick to those, but if we have new topics that people would like to discuss or new information that comes to light, we will put those in there. We have a document outline by chapter and then the timeline of major assumption. Big assumptions would be market price assumptions, gas and electric price forecast. Third party studies missing a "y" there. And a study request from the TAC, anything that comes up there and next slide.

John Lyons: PLEXOS, as we already talked about, it's going to be used to model resource dispatch, resource option valuation and market risk evaluation or analysis. PRiSM is still going to be used for resource selection. That's something we talked about earlier, considering a change in the future. But for this IRP, Aurora will still be used in this IRP for electric market price forecasting, and we will be evaluating other options for the 2027 Progress Report. Idaho IRP, as we discussed earlier, AEG is going to develop the energy efficiency and demand response potential studies. They're going to develop a long-term energy and peak load forecast using end use techniques, and then they'll also be doing a distribution energy resource potential study. That would show types, locations, give us some more data on that. And then we intend to use generic resources functions from several different sources. As we just talked about, is based on likely generation sources, so size even though when it actually goes out to an RFP, the sizes maybe slightly different based on the technologies each company has a, they're all reasonably close to each other, but they'll be some slight differences.

John Lyons: We just had our first TAC meeting and the next one's going to be March 26th in 2024. We'll get the gas and electric price overviews, wholesale electric price forecast, the variable energy resource integration study results. We started talking about those more last IRP cycle and we've done more work on that future climate analysis update and TAC scenarios feedback. We'll have some studies set, that we think you would like to see done, or that we're planning on doing, and then we'll get some input from all of you that you would like to include. These later dates, we haven't nailed down a date yet. We're just checking to see that month wise that works for people and then we'll see which of the timing works. We had a question from Yao.

Lori Hermanson: Yeah, she says, Aurora's market price forecasting depends on dispatch resources. If the dispatch is done in PLEXOS, how can the market price forecast correspond to the resource dispatches?

James Gall: great question. Aurora will continue to do a resource dispatch of the Western region. So, we'll do an expansion capacity study for the region. It just will not be an Avista focus. We'll end up with a regional price forecast for different locations and then feed that price forecast into PLEXOS. I guess the assumption we're making here is the resources that we choose, if they differ, then what the original forecast is by Aurora, that they're not going to impact the regional marketplace and basically what that means is we are a price taker. Because Avista is relatively small, the things that we do are not going to have a major shift in the western market. So, you could definitely argue a small disconnect there. But we think it's pretty minimal to Avista's process just because of our size. And because I brought up a price forecast, or you brought that up Yao, we are looking at using PLEXOS for market price forecasting in the future in a similar way that Aurora does. That is a functionality that it can do. If that proves out plausible in the future, we could do a price forecast and a resource forecast at the same time. I'm fearful that the length of time that it would take to solve maybe a challenge, but long term we are looking at options to use external forecasts for prices for the wholesale market, but we've not made any decisions there. I think there was another question.

Lori Hermanson: Yeah. She asked about if PLEXOS doesn't look at regions, only Avista, and they do have a similar regional database like Avista. Like Aurora does, we currently don't have it purchased, the database, and we're doing kind of a closed system model of just our own system. But that's something that we would consider in the future.

James Gall: Alright, thanks. Go ahead, jump in John.

John Lyons: OK. TAC 3 in April 2024, again we will be coming up with the actual dates on those. Also, if there is any input from the TAC of days of the week you would like us to focus on or to avoid. We generally want to not have TAC meetings on Mondays or Fridays, so we try to focus on Tuesday, Wednesday, Thursday. Then we look at the Idaho and Washington Commission calendars to see when they have major dockets on or open meetings. In April, we will be captivated with Grant's economic forecast and five-year load forecast. That is always a fun one. OK. Maybe just for me as an economist, but we do get good feedback on that long run forecast. The rest of this meeting will be AEG focused and all the studies they've done. That'll be that fundamentals-based forecast that we talked about earlier that they're doing. We'll have the Conservation Potential Assessment that will be split for Idaho and Washington that they've been running for us for several years. There will be a demand response potential assessment and then we'll review the plan's scenario analyses.

John Lyons: The Fourth TAC meeting will be in May of 2024. We will look at the IRP generation options, transmission planning studies and what those costs and what those are going to entail. Distribution system planning within the IRP and the DPAG update that we talked about earlier, trying to integrate our two processes, transmission distribution modeling in the IRP, the L&R balance and methodology to show what loads were serving, what resources we have going out over the next 20 years and then new resource option cost and assumptions. That's where we'll be seeing the big nasty spreadsheet that is the backup for what Lori just talked about showing all the different cost and the nuances of that data, sizes, how much we can get in a year, how long it takes to get it online, environmental considerations, all of that.

John Lyons: The fifth TAC meeting in June of 2024, that is going to be one that is very heavily modeling focused. Maybe if modeling's not your thing, that would probably be a good one to skip. If you want to get into it though, that is always a fun one. We'll have tours of PLEXOS, PRiSM and the new resource cost model. Anything else you wanted to add on that one, James, that'll be nerd fest. It's a lot of fun.

John Lyons: July of 2024, we've got our Preferred Resource Strategy results. That's all that work being done finally results in the mix of resources, types, sizes, timing over the next two decades. We'll do the Washington Customer Benefit Indicator impacts resiliency metrics. Finalizing what we kind of teed up a bit earlier today, portfolio scenario analysis, market risk assessments and the qualifying facility avoided cost for PURPA projects, and then we'll wrap up this 2025 IRP with the virtual public meeting. It'll be joint natural gas and electric. There will be recorded presentations about each IRP side, and a daytime and an evening period for comments and questions where it will be broken out, very similar to what we've seen in the past.

John Lyons: As far as the draft outlined, this is what the chapters will look like. A couple little changes, we've moved some things around, but similar overview. There'll be a short executive summary, introduction, stakeholder involvement, process changes, that's an important one, especially following along to see what's changed one IRP to the next. Then we get into the economic and load forecast, the regional economic conditions, the energy and peak load forecast and the different load forecasts and scenarios. Third chapter is what resources we already have in line, our own resources, contractual resources and obligations, and customer generation, so behind the meter type of things. The fourth chapter is the long-term position, regional capacity requirements, energy planning requirements, reserves and flexibility assessment.

John Lyons: Fifth chapter, we get into distributed energy resource options. We'll have energy efficiency potential, demand response potential, energy storage resource options and the potential for those options for named communities and DER Study conclusions.

John Lyons: Sixth chapter is going to be Supply Side Resource Options, discussion of the different options that Lori had brought up and the characteristics of those plant upgrade opportunities both for our thermal and our hydroelectric facilities. We will also have a discussion of those non-energy impacts that we talked about briefly earlier today.

John Lyons: Seventh chapter, Transmission Planning and Distribution. It's an overview of our transmission system, what the construction cost and integration is going to be for those, merchant transmission plan, and an overview of our distribution system. That's one area we've been expanding over time, is bringing more of the distribution system into the IRP and the DPAG information.

John Lyons: Eighth chapter, Market Analysis. Wholesale gas and electric price forecast and the scenario analysis. Ninth chapter, critical chapter in the IRP, the results, the Preferred Resource Strategy, the market exposure analysis, and the avoided cost.

John Lyons: Tenth chapter, this chapter will be portfolio scenarios and market scenario impacts and then we'll do the Washington Clean Energy Action Plan. That's the decision-making process involved with that resource needs, resource selection, and those Customer Benefit Indicators. This is one that will just be everything for CETA, basically, and then we wrap up with the Action Plan where we look at, as James talked about earlier today, what we've been doing on some of those Action Items. We'll do a thorough overview of where we ended up with the ones from last time and what either is ongoing or came up and we ran out of time, or it's an up-and-coming event or issue that we want to address.

John Lyons: And then the major timeline. December is the goal to have the market price assumptions. Natural gas price forecast and electric price forecast will be in March of 2024. New resource option cost and availability, also in March the deliverables from AEG, all of those studies that they're doing for us, final energy and peak load forecast, efficiency and demand response assessments for potential, the locational energy efficiency and demand response potential.

John Lyons: Sometime a little later in April, transmission and distribution study completion. March 20th, the due date for study requests from TAC members. The earlier you can get those requests to us, the more we're able to accommodate them, that's the date we know we can get to them if we get them by then. If there's things that come up a little later, we might have some room to stretch some of that. But that might be an issue where if we can't, it ends up being as an Action Item. The earlier you can get those to us, the better. May of 2024 will be determining the portfolio and market future studies. June 1st would be finalizing resource selection and model assumptions and you'll notice in this Work Plan. We didn't go into all the details of when things would be written, we will be again sharing those. The plan is to do that through Teams if that works, if not, we'll either do something else, or revert back to how we've been sharing them through the website.

James Gall: John, one thing I didn't see on here is when we will be filing the document and when the draft will out.

John Lyons: I wanted to leave a surprise for everyone. No, I didn't. I forgot to put that on there. We will be filing January 1st. You'll notice, this is a little condensed from the last one. For those of you that weren't with us last time, we had an extension for Idaho because we were waiting for the results of a renewable RFP and we had some significant amounts of resources that came online and we didn't want to put out a plan and then immediately have to change that plan because all these new resources. We had an extension of Lancaster, Columbia Basin Hydro, Clearwater Wind and we had the Myno project at Kettle Falls. There were some major changes that were going on there. I'm trying to remember, January 1st, 2025 will be the date. That also coincides with a CETA rule in Washington that changed our dates. We used to have them due in August, but it's always going to be January 1st now and is it October or is it earlier for our draft?

James Gall: I think it is October 1st.

John Lyons: I will update that final slide.

James Gall: Alright, any thoughts on the Work Plan? John and I have been doing these since 2005 like he mentioned earlier, we've kind of followed the same procedures as we've done in the past. Are there any topics on the TAC meetings that maybe you'd like to see, that you didn't see? That's something you can always email us about later if you don't have anything on top of your mind right now. We are going to be finalizing the Work Plan and filling it with the Washington Commission, I believe on the 1st of October. So, if you have any comments on the Work Plan, please try to send those to us as soon as you can and we'll try to include those in the final filing. We can always revise the Work Plan as we go through time, but it will be filed on the 1st, or if that's not, that's on the weekend.

John Lyons: Yeah. It will actually be in by the end of this week. We'll be getting this wrapped up.

James Gall: Any last comments or thoughts before we wrap up the day?

John Lyons: Alright. Well, thank you for participating in the Technical Advisory Committee meeting. We look forward to working with you for the 2025 IRP. And again, we're always available for questions, comments, all things you just want to chat about for resource planning, we really look forward to doing that.

James Gall: And be on the lookout for your Teams invite very soon, so hopefully it'll work alright.

John Lyons: Thank you. Have a good rest of your day and enjoy getting 50 minutes back.

Meeting Chat:

[9/26/23 8:59 AM] Charlee Thompson: Looking forward to reading the update!

[9/26/23 9:12 AM] Wilson, Kirsten G. (DES): Gall, James I found when I set up an external facing Teams site for a project that DES Energy is doing, that non state individuals invited to the Teams site could access more of the site if they logged into the site via a web browser rather than the Teams App on the computer. Probably the same is true for yours.

[9/26/23 9:32 AM] Brandon, Annette: James, can I comment on this?

[9/26/23 9:33 AM] Moline, Heather (UTC): thanks, annette!
like 1
[9/26/23 9:40 AM] Tina Jayaweera (NWPCC) (Guest)

FYI, The RTF sponsored a study last year on how to quan5ify resiliency value of EE. Details can be found here: https://rtf.nwcouncil.org/other/energy-efficiency-resilience-valuation-methodology-study

[9/26/23 9:42 AM] Moline, Heather (UTC): even more on resilience: pretty simply, OPUC is using presence of solar/storage in low/moderate-income areas with minimal infrastructure and/or high energy burden as a 'proxy' metric for resilience

[9/26/23 9:43 AM] Moline, Heather (UTC): 2023 OPUC Equity Metrics - Energy Trust of Oregon
2023 OPUC Equity Metrics - Energy Trust of Oregon

[9/26/23 9:45 AM] Hermanson, Lori: Thanks everyone for the additional info on resiliency. We'll continue to research these and more and incorporate as it makes sense.

[9/26/23 9:48 AM] Yao Yin: do costs of market purchases and revenues of market sales include wheeling costs and revenues?

[9/26/23 9:49 AM] Hermanson, Lori: Yes

[9/26/23 10:00 AM] Yao Yin: Are all the input data actual data in 2021?

[9/26/23 10:19 AM] Gall, James: we are on break and be back at 10:30

[9/26/23 10:47 AM] Yao Yin: Why did the model NOT select those storage?

[9/26/23 10:53 AM] Yao Yin: AURORA's market price forecasting depends on dispatch of resources. If the dispatch is done in PLEXOs, how can the market price forecast correspond the resource dispatches?

[9/26/23 10:55 AM] Yao Yin: PLEXOS doesn't look at regions, only avista?

[9/26/23 10:55 AM] Yao Yin: thanks!

[9/26/23 11:08 AM] Charlee Thompson: Thank you!

[9/26/23 11:08 AM] Dennis, Joshua (UTC): Thank you