BEFORE THE ARIZONA POWER PLANT LS-371

AND TRANSMISSION LINE SITING COMMITTEE

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY, IN CONFORMANCE WITH THE REQUIREMENTS OF ARIZONA REVISED STATUTES SECTION 40-360, ET SEQ, FOR A CERTIFICATE OF ENVIRONMENTAL COMPATIBILITY AUTHORIZING THE REDHAWK POWER PLANT EXPANSION PROJECT, WHICH INCLUDES THE CONSTRUCTION OF NATURAL GAS TURBINES, A 500kV SWITCHYARD AND RELATED FACILITIES, ALL LOCATED TWO MILES SOUTHEAST OF THE INTERSECTION OF ELLIOT ROAD AND WINTERSBURG ROAD IN MARICOPA COUNTY, ARIZONA.	DOCKET NO. L-00000D-24-0156-00234 EVIDENTIARY HEARING

At: Goodyear, Arizona

Date: August 20, 2024

Filed: August 27, 2024

REPORTER'S TRANSCRIPT OF PROCEEDINGS

VOLUME II

(Pages 146 through 408)

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BE IT REMEMBERED that the above-entitled and numbered matter came on regularly to be heard before the Arizona Power Plant and Transmission Line Siting Committee at Hampton Inn & Suites, 2000 North Litchfield Road, Goodyear, Arizona, commencing at 9:00 a.m. on August 20, 2024.

BEFORE: ADAM STAFFORD, Chairman

LEONARD C. DRAGO, Department of Environmental Quality
ROMAN FONTES, Counties
(Videoconference appearance.)
DAVID FRENCH, Arizona Department of Water Resources
JON H. GOLD, General Public
NICOLE HILL, Governor's Office of Energy Policy
R. DAVID KRYDER, Agriculture Interests
MARGARET "TOBY" LITTLE, General Public
(Videoconference appearance.)
GABRIELA SAUCEDO MERCER, Arizona Corporation Commission

APPEARANCES:

For the Applicant:

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APPEARANCES (Continued):

For the Intervenor Western Resource Advocates:

WESTERN RESOURCE ADVOCATES
By: Emily Doerfler
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Phoenix, Arizona 85004
(Videoconference appearance.)

CHMN STAFFORD: All right. Let's go back on the record. We have been joined by members Kryder and Hill and French -- Member French is in the flesh today instead of attending remotely, so welcome members.

Mr. Derstine, I believe you were still in the middle of direct for Mr. Eugenis.

MR. DERSTINE: That's correct. Good morning, Mr. Chairman, members of the Committee.

(Michael Eugenis was previously duly affirmed by the Chairman.)

D I R E C T E X A M I N A T I O N (Cont.)

BY MR. DERSTINE:

Q. Mr. Eugenis, I think when we ended the day or at least ended your testimony yesterday at around 4:30, you had just wrapped up your discussion of the integrated resource plan, and I think there was a question, maybe it was a -- maybe it was a two-part question that you answered concerning gas capacity, and I think after the hearing you said oh, I'm not sure I answered both parts of that question. So do you want to address that now?

A. (MR. EUGENIS) Yes, thank you, Mr. Derstine.

We received a question yesterday about our ability to fuel the proposed units in the Redhawk Expansion Project, in addition to the other units that are in the surrounding region, and I had maybe a little hastily answered just "yes" to that question. I just wanted to clarify that point that APS has ensured that we have sufficient gas transportation rights to fuel our facilities, but I cannot speak to the other entities that both own facilities or may have transportation rights on the pipeline, but in our study work we're quite confident in our ability to fuel these -- these proposed units at Redhawk.

Q. Okay. Anything else you wanted to cover from yesterday?

A. (MR. EUGENIS) No, sir, I'm prepared to do a transition here unless you want to start me.

Q. Well, I think the transition is we're moving to a new subject, a new topic, the All-Source RFP, the 2020 All-Source Request for Proposal. So I'm not quite sure what you have planned but do you want to start with just a general discussion about that, what is the All-Source RFP?

A. (MR. EUGENIS) Absolutely.

And thank the Committee members yesterday too, we've made it through the most technical part of my discussion today, and so breathe a little bit easier, the next portion of this should be a little bit more familiar and I think is a little bit less abstract in the concepts provided. So thank you for bearing with me yesterday as we moved through some kind of complicated things.

The IRP, as you recall yesterday, uses generic cost information whenever we put together our assumptions and those portfolios are developed. And so using public sources that's where that cost information comes from, but ultimately, we need to know what are the projects that are available to APS to contract with and provide capacity for our customers. And we do that through the All-Source RFP, or request for proposal process.

And so this is our time to solicit the market, provide some information as to what APS is looking for, what time frame we're looking for, those resources, and actually receive those specific bids, specific projects and locations for us to evaluate in terms of what makes the most economic portfolio, maintaining reliability for our customers.

So the 2023 All-Source RFP is where this project was bid in and where I'm going to focus my comments today in terms of how we approach that RFP, the evaluation method that we use for the IRP -- or the RFP, and just give you a little bit more information of how that process is conducted.

At the highest level, the '23 RFP solicited for about a thousand megawatts of reliable or on-peak capacity. It was focused on years 2026 and 2028, which means that we were looking for projects that could go in service between those years, so '26, '27, and 2028. We also stated as part of the RFP that we are looking for at least 700 megawatts of renewable resources, but ultimately we would select a portfolio based off of the bids that we receive, the pricing information of those bids and the changing needs of our customers, quite frankly.

We also identified some specific opportunities within that RFP, the Redhawk location is one of those specific opportunities. We also identified Sundance which is another location that APS already has existing generation at, as well as the Agave Solar Facility for the potential for battery energy storage to be added and then another development project that APS has that's to the west of the Redhawk facility that we're looking at, potentially some solar and energy storage additions there as well.

Q. So when you -- sorry to interrupt you -- when you say you identified opportunities, I gather what you mean by that is APS identified locations, Redhawk Plant, for example, where projects could be developed, and the All-Source RFP specifically asked for proposals to develop resources at those locations?

A. (MR. EUGENIS) Exactly. So these are locations that we have existing infrastructure or we have existing development opportunities and we're identifying them as where we think there may be value for our customers. So certainly not a guarantee that we would select bids from these specific opportunities, but we want to give information to the marketplace and to developers to say we would like you to look at these areas, sharpen your pencils here, and provide any bids or projects that you have for these areas, because we think that they may compete favorably.

Q. I guess with that background on the All-Source RFP, I think looking ahead you have some slides that are going to take the Committee through the RFP process?

A. (MR. EUGENIS) That's correct.

So at the highest level, the RFP goes through kind of these four categories as we look at the evaluation of the bids that we receive. And so this covers the work that my team does as we look at the specific projects that are bid into that RFP, and then, ultimately, as we create that least-cost group of resources that maintain reliability for our customers.

At -- so at a high level, it goes through the bid compliance phase, which is really just reviewing the bids for completeness and conformance with the RFP requirements. It goes through an analysis phase where we look at all of the specifics of the project and so calculate some kind of key metrics associated with those projects. Finally, we then short list, which is now a condensed list of projects that we're actually going to pursue negotiations with, and then we take that short-listed project list and we put that through the same tool that we use for the IRP, which is that long-term capacity expansion tool that we talked about yesterday to identify what that least-cost portfolio is.

So I'm going to spend a couple of minutes on each of these different categories just explaining them in a little bit more depth. And then I'm sure my legal counsel will have a couple of questions on the way and welcome any questions from Committee members as well.

At the beginning, during the bid compliance phase, we talked about this as being an All-Source RFP, and so it can be a little bit of a misnomer in that not every single bid that we receive is necessarily qualified as part of that All-Source RFP. I said that we were focused on years 2026 through 2028, so projects outside of that time frame do tend to be disqualified as a part of this, because we really want to focus our procurement on those projects that will serve the needs of our customers here in the next couple of years.

We also screen for completeness of data as well. There's a lot of technical information that's necessary. There's a lot of compliance information, as well as commercial requirements that come in developing projects of this size and scale. And so we want to make sure we have all of that necessary information that's been provided from the bidders at this stage before we move forward to doing some actual analysis on those bids.

This part of the RFP is a pass/fail process. So really you've got -- there's not a ranking that occurs at this time. This is more focused on do we have the information that we need and do these bids qualify to be as part of the -- the RFP.

CHMN STAFFORD: About -- how is the RFP structured? Are you just -- are you looking for provision of power during certain peak hours or is it -- is it you can provide power 24 hours a day with emphasis on certain hours? How was it -- how was it structured?

MR. EUGENIS: Chairman Stafford, thank you for that question. We identify -- we provide a heat map of higher-value periods as part of the RFP, and so that gives some indication to bidders of where we see resources that would be more valuable to our system and where we're looking for those bids. In the past, you've seen more specific RFPs come from APS, and so we may RFP specifically for a peaking resource or we may do something that's more targeted towards renewables.

As we did this All-Source RFP and as we've kind of learned best practices in the industry, we try to keep it more open. And so by using that heat map I've identified where there's more value, but ultimately, it's not just peaking resources that I'm looking for, it's not necessarily just energy resources I'm looking for. I really need that fulsome group that's going to provide both the capacity that our customers need, as well as the energy.

CHMN STAFFORD: Perhaps you could explain what a heat map is a little better. I mean, I'm sure there's a member that's going to ask "What's a heat map?" here pretty soon, so let's -- I want to jump -- jump ahead and just have you do that now, please.

MR. EUGENIS: Chairman Stafford, thank you for that question. In this context, a heat map shows higher-value periods of time compared to lower-value periods of time. So we provide it as a year, and it shows hours of the day in that year and identifies where, on average, we see essentially power prices be higher or where we have needs on our system which, you know, just in kind of pure economic terms scarcity drives prices higher. And so by providing that value information on kind of a -- both an hourly basis and throughout the year, it gives us that -- that ability to communicate what resources would be valuable to the system.

CHMN STAFFORD: Thank you.

MEMBER KRYDER: Mr. Chairman?

CHMN STAFFORD: Member Hill, then Member Kryder.

MEMBER HILL: Thank you, Mr. Chair.

I always think of RFPs being requests for consultants or companies to respond, like a merchant. How does -- how does capital investments that APS wants to build and make as part of their system relate to the RFP process? Are you competing with -- do you put your own projects in to compete with merchant projects? How does that -- how does an APS project work in that way?

MR. EUGENIS: Member Hill, thank you for this question. This is a fantastic question. Any development that APS takes -- or undertakes needs to compete as part of this RFP process as well. So we want to make sure that our customers are getting the best value for projects that exist. And so external developers bid in their projects, and we obviously look at those bids, and those are not for APS ownership, but we also receive bids that we typically call, like, an engineer procure and construct, or EPC, bid, which would be for an entity to perform those tasks for a project that ultimately would become APS ownership into the future.

So in the case of the 2023 RFP, APS itself did not bid in, however, we are soliciting the marketplace for entities to perform EPC-like services for us for projects that ultimately APS can own. And what's important about that is they compete on the same level as everybody else. And you're not going to see kind of the ownership projects in a silo or treated differently than other developer projects.

MEMBER HILL: Great. Thank you.

CHMN STAFFORD: Member Kryder.

MEMBER KRYDER: Yes. I sure appreciate the insight that you're giving into the selection of first the bidders and ultimately the successful bidders on your RFPs. Do you have -- I hope this is not seen improperly -- but do you -- do you take bidders from outside the U.S.?

MR. EUGENIS: Member Kryder, I don't know the location of all the bidders that come in. Some of them may have headquarters outside of the U.S. Typically, we rely on bidders and tend to contract with bidders that have quite a bit of development experience both in Arizona or throughout the United States. There's several partnerships that, you know, we've found and found value in as we've gone through several of these RFPs over the last couple of years, and that development experience is definitely a part of our evaluation and frankly, is how we know that we're going to get a quality project at the end of this. And so those companies tend to have quite a bit of either projects here in Arizona, they may have projects that are already connected with APS or a significant portfolio of resources in the United States.

MEMBER KRYDER: Okay. Thank you for that. Looking -- and I don't mean this as a slap in any way -- but at the dark side of that, does that mean you have to be a member of the club to really get through?

MR. EUGENIS: Member Kryder, no, as part of the RFP process, and as you'll see in a slide or two here, cost is the number one weighting factor as far as our evaluation of these bids. We want to drive value for our customers above all, making sure that we maintain reliability at that same time. And so while we do evaluate some of the respondent risk as well as, you know, what is the commercial feasibility of some of these developers, that cost is their number one priority in terms of capturing value.

MEMBER KRYDER: Okay. So I hear reliability and cost are what drive you toward your final decision; is that correct?

MR. EUGENIS: Yeah, Member Kryder, that's correct.

MEMBER KRYDER: Okay. And the reason I raise that is, as we are in an increasingly global situation, and there are really some fine, fine companies ex-U.S., just as a thought, do your RFPs, are they published internationally or how -- how does the -- how do the applicants find out about you, about a RFP better said?

MR. EUGENIS: Member Kryder, we do publish our RFP on our website. We also use, and in the past have used, an external consultant that works with many companies inside the United States, and has an extensive network of developers that they've interacted with through other RFPs. And so we leverage, almost like a mailing list, to make sure that those respondents are made aware of it. I'm not aware of any industry publications that we use to publish the fact that we're going out for a RFP, but I'd have to check to be sure.

MEMBER KRYDER: Thank you very much. That's -- might be an interesting cost saver in the future. I don't know what the -- oh, my goodness -- what

Corporation Commission or other of your ratepayers or other groups that you face would say about this, but there are some really fine ex-U.S. companies that might save you a nickel or a dime.

MR. EUGENIS: Thank you, Member Kryder.

CHMN STAFFORD: Member Fontes, you have a question?

MEMBER FONTES: Yes, Mr. Chairman. I apologize about the camera, I'll have it restored shortly.

But the question is, can you relate on this particular RFP the exact evaluation criteria and then the percentages of those criteria to the heat map? I'm -- I've been on the IPP side and I've been on the evaluation side for procurement, particularly on the transmission side. So on this one that this was awarded, though, how does that heat map relate to the overall scoring on the score card for that particular year is what I'm looking for? Appreciate you.

MR. EUGENIS: Member Fontes, the heat map is derived from our actual modeling software. And so previously in my testimony, I talked about our long-term capacity expansion modeling, which is how we identify that least-cost portfolio. My team also does an even more precise level of modeling called production cost modeling. And production cost modeling solves at a higher granularity than the long-term capacity expansion modeling does, and is actually how we check those long-term capacity expansion results into the future. That modeling software is the source for the heat map information, so it identifies what the pricing or what the valuable times of day or times of year are for our customers. As we go through the RFP process, though, and as you'll see on, I think my next slide, we use more generic pricing mechanisms or generic metrics to be able to compare different projects as part of that RFP. And I think -- I think I'll move to that slide now, actually, because I think that our conversation has kind of matured to this point.

The purpose of the more simplistic metrics that we use as part of this analysis phase is essentially to be able to group different types of resources together, and then be able to compare them amongst each other. And so before I take that next step of inputting all that information into my model and really turning the crank on an optimized solution, first I want to know of the bids I received, which ones of these are competitive with each other.

Maybe a useful analogy here is if you have 10 Ford F-150s that are sitting in front of you with similar but maybe not exactly the same options, and you've got different prices associated with each of those, that -- those F-150s all basically do the same thing. They all have beds, you can tow with them, they can probably tow similar amounts. And if one of those is 25 percent more expensive than another, I know that I don't need to spend time negotiating with that or even evaluating that project into the future, because there's just a price premium associated with it. So our analysis looks to basically stack these resources in groups of you can think of them like F-150s in front of you, or other, you know, vehicle types, other resource types to compare them together before moving to that next stage.

Member Fontes, does that help?

MEMBER FONTES: Not really. I appreciate the prediction cost modeling. I'm actually beyond that. So when you score it out on your score card for the final selection beyond the initial, what I would call screening, which you just explained, and you get to the resource alignment technology risk price, respondent risk, so the cost is 50 percent of the weighted criteria for the final award; is that what I'm reading here?

MR. EUGENIS: That's -- Member Fontes, that's correct. It's 50 percent of this analysis phase, which determines the short list. So that's how we move into the short-list process. You used the term "final award," which made me think of when we actually execute these contracts and the execution of the contracts doesn't take place until we go through the portfolio analysis piece, which identifies that that portfolio or group of resources that's necessary.

MEMBER FONTES: What I'm trying to get at is you got an initial review of the bidders and then you have a subset of bidders, what is that final criteria that you use to select this particular plant, so we capture that for the record, if that's helpful. And explain that in terms of, like, that final selection criteria, is it cost that's the 50 percent that's really looked at there? Help us capture that for our understanding here.

MR. EUGENIS: Member Fontes, you're correct that that final criteria really is the output of the portfolio analysis tool, which heavily weights cost and the best-fit resources to maintain reliability. So Mr. Cole spent quite a bit of time yesterday in his testimony talking about we need different resources for different things. The IRP, as you remember from my testimony yesterday, also identifies quite a few different resources together, and then ultimately that portfolio analysis tool takes the cost of the bids that are available to it, and creates that least-cost portfolio that maintains reliability.

So if I were to tell you, like, in general the metric that's most important to us here is cost at that reliability threshold.

MEMBER FONTES: Can you do me one favor more, can you now relate it back to when you introduced this, and you said when we framed up this vintage years RFP, we talked about that we had some preferred locations. Can you relate it back to how that relates back to the transmission planning because this is a generation asset, but I think when you look at that, you were pinning some areas that you know are going to help the balancing authority and the load factors on the transmission side. And it is -- how does that relate back to this final determination?

MR. EUGENIS: Member Fontes, we do also screen for transmission and the ability to deliver these projects on our transmission system. So as part of the total cost of a project, I'd have to make sure I account for the interconnection costs. And so for some projects, like the one that we're talking about today, those are fairly minimal. We're just talking about expanding an existing substation, adding some bus works and breakers, et cetera, and I think Mr. Spitzkoff can give you more information on those specific network upgrades that are necessary.

Other projects, as part of their interconnection evaluation, which is handled by a separate part of the business, may have additional transmission needs outside of just the substation that's necessary to connect them. And we have to take into account those costs as part of that overall project cost as well.

So by identifying these specific opportunities, we're identifying places where we believe that there may be existing transmission and then, therefore, less overall cost associated with the project, which means that it will compete favorably overall. However, that does not guarantee a bid will be selected from these -- these categories, they still have to compete.

MEMBER FONTES: So when you did the analysis, it started with the IRP, it broke it down for this particular All-Source, it factored in what is the optimal generation that could support both the demand side, the transmission factor, and then that is ultimately how you guys came to this decision, and said that a peaker plant is better than, per se, energy storage or additional renewable resources.

Is that -- is that a good summary so that when we get to crafting the Certificate of Environmental Compatibility and we have to address issues like availability and reliability that sort of captures this for you?

MR. EUGENIS: Member Fontes, that's correct.

MEMBER FONTES: Mr. Chairman, I appreciate -- appreciate the time, and that's all I have.

CHMN STAFFORD: Thank you.

Member Gold, you had a question, and then Member Hill.

MEMBER GOLD: Mr. Chairman, thank you.

Here's the question I have: Along the lines of Member Fontes, and you gave him an answer, I want something very simple. Going back to your bid compliance RFP requirements, were you specifically looking for a power supplier that could turn on and turn off when needed or were you just putting this all out to set somebody who could throw in 700 to 1,000 megawatts? Were you specific in your -- what you were looking for or were you just, say I'll look for everything, and whoever comes close to what I really want is what I'm going to narrow it down to? How did you define your requirements to the bidders?

MR. EUGENIS: Member Gold, we open it up to any number of technology types, and so we didn't limit it to just those that can be dispatchable or flexible. However, in our evaluation criteria we do have those as categories that are ranked among the bids that are proposed, and so --

MEMBER GOLD: Wait, before you go on, right there at that point is my question. When you sent this bid out, what was your ranking, did you need something that you can turn on and off the power, like a LM6000, or could a solar plant or a wind plant or, oh, God knows, any of the --

MEMBER FONTES: Battery energy storage --

MEMBER GOLD: Yes, please. Thank you. Or battery energy stor- -- were you specifically looking for something you could turn on and turn off, or did you just need 700 to 1,000 megawatts in the middle of the night or in the middle of the afternoon, you didn't care? Where were you going with this?

MR. EUGENIS: Member Gold, we needed all of those resources as a part of the All-Source RFP. We identified a need for a quick-ramping resource that's dispatchable and flexible as part of the IRP, and that --

MEMBER GOLD: How is that weighted, before you go on?

MR. EUGENIS: Member Gold, as a part of this analysis part, we don't necessarily weight the projects against -- the different technology types against each other yet. Because it's very difficult to compare technology types that have different attributes to them. And so just like how solar kind of only shines during the day and wind only is available when it blows, it's difficult to say if you were to, outside of our modeling software, compare those two technology types really which one is the best. And, frankly, we need a group and we need a portfolio of those technologies to maintain reliability for our customers.

And so when we perform that portfolio analysis, it identifies both solar projects that are necessary to maintain reliability, wind projects that are necessary to maintain reliability, and resources of this type which provide that dispatchability and flexibility.

MEMBER GOLD: So what you're saying, if I understand you correctly, and I may not, is you're putting this RFP out in general, not just for this project, but for many future projects, because as I understood yesterday from Mr. Cole, we need specifically a project that can give us power when the sun goes down when people come from home from work, which is what this thing is aimed at. But you weren't just looking at that period, you were looking at a broad -- or a need for, say, a thousand megawatts of power within the next three to 15 years, or whatever, and therefore, you set this out so that you would not have to reinvent the wheel and go looking for other projects who already had people who could acquire them and this one just fit according to your rankings for the specific time period; is that correct?

MR. EUGENIS: Member -- Member Gold, that is correct.

MEMBER GOLD: Thank you.

CHMN STAFFORD: Member Hill?

MEMBER HILL: Thank you, Mr. Chair.

So for this initial cut, this is the criteria that you've used, can you help me better understand what you mean by, "technology/project risk" and "respondent risk"? Can you characterize that a little bit more? Like is respondent risk their credit score or can you just -- or how you define "project risk"?

MR. EUGENIS: Absolutely. Member Hill, thank you for this question.

Maybe I can spend a couple of moments on this slide, because I think we got here a little bit prematurely from where I was at in my presentation, but --

MEMBER HILL: Thank you.

MR. EUGENIS: -- the four categories that you see here are resource alignment, technology and project risk, respondent risk, and cost, being the largest factor. Resource alignment consists of dispatchability, the carbon emissions associated with the project, load factor impacts, and flexibility.

The -- the technology or project risk aspect is consistent of site control, the interconnection status, which Member Fontes brought up as part of his question around transmission, as well as any supply chain impacts that may be specific to that project. And you can think that there's many different sources for the different technologies that -- that we utilize, so there can be different supply chains that impact that.

MEMBER HILL: And pardon my interruption, but in that project risk, when you say "site control," does that include permitting processes, or permit -- I mean, do you look at the project and say, "Oh, they might have a hard time getting XYZ permit for that"? Maybe, because we talk about air quality so much, it's Pinal County or Maricopa County air district, I mean, is that part of the site control when you -- in that project risk piece, do you include that?

MR. EUGENIS: Member Hill, while we may not explicitly include air permitting as part of site control in terms of, like, if you --

MEMBER HILL: Or zoning or, you know, getting -- permits, in general, how does that weigh in?

MR. EUGENIS: We absolutely take that into account. And where the respondent is in that process, in terms of do we believe that these projects really are going to come to fruition on the time frame that they say that they're going to come to fruition.

MEMBER HILL: So that's the project risk category?

MR. EUGENIS: That's correct.

MEMBER HILL: Okay. Great.

MR. EUGENIS: So an example of that would be if a project has identified some permitting that we have experience in and know takes several years and says that their project is going to be online in two years, obviously there's a huge risk associated with that project if they haven't completed that permitting already.

MEMBER HILL: Yeah, that's not a CEC, just so we're clear. We're not on that list, that long list. But go ahead.

CHMN STAFFORD: There is no backlog.

MR. EUGENIS: Yeah, thank you, Member Hill.
BY MR. DERSTINE:
Q. Mr. Eugenis?
A. (MR. EUGENIS) Mr. Derstine.
Q. I realize that, you know, you've got a lot of fast thinkers here on the Committee, and you're getting questions that are tasking you that maybe go more to the portfolio analysis or they're taking you ahead of kind of how you planned to walk us through this. So let me just -- let me add to that and have you back up to maybe slide 82 in your -- that deals with the Integrated Resource Plan.
CHMN STAFFORD: Member Fontes, you had a question?
MEMBER FONTES: Yes, sir.
Yes, sir, it just related back to that previous slide, and I appreciate you going back for the other item, but how do you do the interconnect evaluation when you're the one who grants the interconnect? Is that done by a firewall? And then is respondent risk past performance? And how do you look at that at APS? Are you looking at your past performance on a similar project? It's sort of, like, a self-scoring, so just for the record, how do you separate to score an APS project who might be bidding with other bidders an All-Source?

Thank you.

MR. EUGENIS: Member Fontes, on your question as it regards to respondent risk, there's three broadcast categories that we evaluate there, which is commercial experience, safety, and financial strength. There are some measurable metrics that we use in those areas, and I can't speak to the exact specifics that we had in the 2023 RFP, but some examples of metrics there could be number of projects and size of projects that they have under development or basically how large their portfolio is. There is some safety data available for these large-scale developers in terms of number of OSHA recordables, their ranking in terms of safety performance. There are some specifics that at the break I can look up to give you more exact information on how we measure safety. But there is some industry data available to us for measuring safety.

And then financial strength has to do with their ability to provide letters of credit to satisfy our requirements and making sure that they have the necessary financial backing to go through what these projects all are basically in the hundreds of millions of dollars of development cost.

MEMBER FONTES: Just to follow up, and then the interconnect you -- your evaluation came in separate from the folks who actually do the interconnect work, just for the record?

MR. EUGENIS: Member Fontes, that's correct. And Mr. Spitzkoff can speak more at length in terms of how the interconnect process takes place at APS, but that is an arm's-length transaction from -- from my group in --

MEMBER FONTES: I was focused on the arm's-length, so Mr. Spitzkoff, I got the other piece.

Last question, on this particular RFP, were there other gas peaker bidders or were you the only one?

MR. EUGENIS: Member Fontes, there were a number of other bids, both at Redhawk itself, as well as broadly that could connect to the APS system. At Redhawk itself, I believe there was two bids that were submitted.

MEMBER FONTES: For gas peaker?

MR. EUGENIS: Member Fontes, that's correct.

MEMBER FONTES: Thank you.

CHMN STAFFORD: Quick follow-up on that. So there was the one from APS for this project and another from some other entity that would build a similar project at this site?

MR. EUGENIS: Chairman Stafford, I apologize, can you repeat your question, please, sir?

CHMN STAFFORD: You said there were two bidders for -- in the RFP for the gas project?

MR. EUGENIS: Chairman Stafford, my -- my esteemed colleague here, Mr. Van Allen, corrected me, there were three bids, I apologize.

CHMN STAFFORD: So one of which is APS to self-build it, which is what we have here, correct?

MR. EUGENIS: There is an ownership option -- or, Chairman Stafford, there was an ownership option that we talk about in terms of an engineer, procure, construct, or EPC. I view that differently than an APS self-build, in that the bidder in this case submitted that information outside of APS itself developing that bid, and then having another member of the APS organization submitting that bid to us or into that process.

CHMN STAFFORD: Okay. So the successful bidder for this project, it's an engineer, they're going to engineer design and build it, and then transfer ownership, you call it a turnkey operation, is that what that is?

MR. EUGENIS: Chairman Stafford, I've heard that term before, like a turnkey project. I think it applies here. We usually use the term "engineer procure construct." There's a couple of different commercial terms that I think apply here with legal definitions associated with them. That's why I usually use "EPC."

CHMN STAFFORD: Okay. And so the three bids were all EPC for this site?

MR. EUGENIS: Chairman Stafford, we actually received a PPA bid as well -- and I'm going to pause for one second -- there was several PPA bids --

CHMN STAFFORD: Okay.

MR. EUGENIS: -- that were received and then this EPC bid that we're discussing here today.

CHMN STAFFORD: And the PPA bids were to build at the same site, at the Redhawk site?

MR. EUGENIS: Chairman Stafford, that's correct.

CHMN STAFFORD: Okay. All right. I wanted to just get a clear picture of what we were talking about in terms of the bids. Thank you.

Member Fontes, did you have another question, I see your hand's still up?

MEMBER FONTES: Yes, sir. Just a clarification, because I think the word "EPC" has a different definition for the way we've seen it in other hearings. EPC is associated with more of the construction aspect. Design-build transfer is when it's designed, built, and transferred either by a utility or an entity that develops and constructs and then transfers the asset. So for the sake of consistency, Mr. Chairman, I think we should be using "design-build transfer" here, and not "EPC" as the applicant suggested.

MR. EUGENIS: Member Fontes, I will -- I acknowledge that there is a number of different terms that are available in this space. You've probably also heard "build transfer agreements" or BTA. There's also "build own transfer," which is a BOT agreement, and all --

MEMBER FONTES: Those are more common for ownership in terms of the equity and the rate basing, so I would tend to suggest we use those, because the EPC is more on the construction. A PPA could have an EPC as well. Again, we're doing multiple hearings here just for the sake of consistency, prefer to use the "design-build transfer" in this case.

MR. DERSTINE: Yeah, I guess, Member Fontes, the --

MEMBER FONTES: Appreciate it.

MR. DERSTINE: And I don't want to get mixed up in the terminology, because I'm way out of my depth, but I think the reality is, is that APS owns this site --

MEMBER FONTES: Yup.

MR. DERSTINE: -- so as I understand it, the negotiations with the successful bidder for the construction of Redhawk is an EPC contractor, and those negotiations are ongoing. And the members of my panel can correct me if I'm wrong.

MEMBER FONTES: It's a self-built asset, though?

CHMN STAFFORD: I think not technically because the successful bidder will design, construct, and then at that point ownership will transfer to the utility. It's not like APS is going to design it and build it itself, correct, it's hired someone else to do it?

MR. EUGENIS: Chairman Stafford, that's correct.

MEMBER FONTES: But is it recorded as CWIP, construction work in progress, as a part of the rate base because that means it's owned from the development, the design and permitting, so that would be a design-build technically.

CHMN STAFFORD: Well, I guess that means -- I guess that depends on who's -- who's writing the checks, right? I mean, if APS is writing the checks for the construction as it's done, as opposed to cutting the check to purchase the asset when it's done. Is that kind the distinction you're trying to make?

MEMBER FONTES: Yes, sir, I think that's important here.

CHMN STAFFORD: And, I guess, you know, depending on the answer to that question, I guess, the follow-up would be is this asset eligible to be included in a new adjuster? I can't recall the acronym off the top of my head, it was --

MR. DERSTINE: SRB.

CHMN STAFFORD: SRB, there you go.

MR. DERSTINE: I don't have any members of this panel who are, I think, able to speak to, one, how this would be treated in rates, whether or not it's going to be included in the SRB. I think that's a decision, I think the view is this would be an eligible asset. But how those things fall out in a rate case and the regulatory decisions around that remain to be made.

CHMN STAFFORD: Okay. So I guess is there going to be a witness that would be able to answer some of those questions? I mean, we've only got the first three up here, you've got five more on the docket here, so --

MR. DERSTINE: I don't have any rate experts lined up, but we can dig into the question and see if we can get you a different -- a more detailed answer.

CHMN STAFFORD: Okay. Yeah, because I'm just --

MEMBER FONTES: And, just for context, we had a merchant plant that isn't eligible for CWIP and rate base, and it was -- they were using EPC contract, so I think for the public and for the record we just need to be a little more precise on that, just so we're consistent between case to case.

I appreciate you. Thank you.

MR. DERSTINE: Thank you, Member Fontes.

CHMN STAFFORD: Yeah, because I think you were interested in how the -- how it's going to -- eventually since APS owns it, it will end up in rate base. And I think we're just kind of curious and the Commission might be curious to find out what APS anticipates the timing of that being. You know, are they trying to put it in there before it's fully online, or is it going to wait until it's operational and then it would be included in the SRB after APS actually takes ownership of it? I think those are just kind of --

MEMBER FONTES: And I -- Mr. Chairman, and I think it's important because you made a self-build determination here. You have an IRP process, and arguably, a public policy reason to put this asset for systems reliability, whereas, the peaker plant case that we just saw proposed that, but I'm still not convinced that that -- that asset has the same, if you will, rationale and justification that you need. So I'm trying to capture that here.

MR. DERSTINE: Understood. We'll see if we can get you some more detail on that.

CHMN STAFFORD: Thank you.

MR. DERSTINE: I guess assuming with the understanding that, again, you know, rate decisions and how this would fold into rates and rate impacts are not something I can -- I have the witnesses for and, frankly, I'm not sure are part of the scope of the Committee, but we're happy to answer your questions as best we can.

CHMN STAFFORD: I'm sure -- I'm sure the Commission is going to be interested in those issues anyways, so it seems like to get in front of it and have those answers ready before you get to the Commission, because until they approve it, it's a -- it's still in the wind.

MR. DERSTINE: I hear what you're saying, and I think you're probably right.

CHMN STAFFORD: Thank you.

MR. DERSTINE: Yup.

Q. I took you back, and I apologize for that, you were hoping to move forward. But Member Gold had a question about did this All-Source RFP specifically ask for this kind of peaking capacity that Redhawk represents, the expansion project. So I wanted you to maybe go back to this and I think the answer is the All-Source RFP, as you said, asked for proposals to satisfy a number of asset needs that were identified in the Integrated Resource Plan; is that right?

A. (MR. EUGENIS) That's correct.

Q. Okay. So what you're looking at on slide 82 are the resources that were identified in the 2023 IRP that you went out through the All-Source RFP to satisfy and to get bids for?

A. (MR. EUGENIS) That's correct.

Q. Okay. And so included in that would be the fast-ramping peaking capacity that the Redhawk Expansion Project represents, but you also sought bids for solar, wind, storage, et cetera?

A. (MR. EUGENIS) That's correct.

Q. Okay.

MEMBER GOLD: Mr. Chairman?

CHMN STAFFORD: Yes, Member Gold.

MEMBER GOLD: Thank you to Mr. Derstine.

MR. DERSTINE: Derstine.

You can say Derstine.

MEMBER GOLD: No, no, I'll get it the right way. Derstine?

MR. DERSTINE: Yeah, that's how I say it. I'm not sure I'm right, but I think --

MEMBER GOLD: Well, we'll just assume it's correct at the moment.

MR. DERSTINE: Okay. All right.

MEMBER GOLD: Mr. Derstine, thank you for clarifying that.

MR. DERSTINE: Sure.

MEMBER GOLD: So that means that we're -- we put this report out looking for everything for present use and future use, and we're focused on right now what we needed primarily which was energy efficiency, which the Redhawk Plant seems to accommodate most efficiently and most financially acceptable; is that correct?

MR. DERSTINE: I think it falls into that gray bucket of natural gas.

MEMBER GOLD: That's what I was looking at.

MR. DERSTINE: Yeah.

MEMBER GOLD: In that case, thank you for clarifying that.

CHMN STAFFORD: Member Hill.

MEMBER HILL: I had a question about this slide. And I missed yesterday, so I hope my question is still novel. I missed a chunk of yesterday. How does -- can you give me an example of demand response in your evaluation in the RFP process? How -- is there a resource that -- I know what demand response is, but I'm just kind of --

MR. EUGENIS: Member Hill, this is a great question, because, I mean --

MEMBER HILL: I've gotten two great questions, for the record. I just want you to note that.

CHMN STAFFORD: So you're talking about an example of what a bidder would be for a demand response, what it would look like?

MEMBER HILL: Yeah.

MR. EUGENIS: So I'd like to start first, and I know you know this already, but a demand response product is something where you can shift load from one period of time to another period of time or eliminate your load altogether. And so APS has a number of examples of demand response products out there, some that you may be familiar with is our Cool Rewards Program, which is our thermostat program, and it sounds like Member Hill may be a participant in that. We appreciate that. It's a valuable program for us. And that allows us, right, to send a signal to customers or to participants. They reduce their demand for a period of time, and then once those system needs kind of are alleviated, then we allow you to kind of turn your thermostat back down, that increases your load, but at a lower cost time for us as the utility, which benefits all ratepayers.

Your question on what a bid would look like for that is, there's a number of different aggregators that exist in the industry that basically group customers or will interface with customers or participants in these demand response programs, and then offer them as a package to the utility, and then manage some of the specifics in terms of customer acquisition or enrolling them, customer enrollment in those programs, and the actual communication to them in terms of sending a signal for them to reduce their load.

MEMBER HILL: I love this. Thank you for that. I feel like at the end of the day, you know, there are two pieces to this reliability, it's, you know, providing the resources, but also the demand response side of it is just curbing how much we use, so that we don't have to build so much and it doesn't cost so much to everybody. So I love this and I didn't know it existed, so thank you.

CHMN STAFFORD: Do you have any bids that are more like a large industrial or commercial customer that can shave load at certain peak times, like when you get to, say, 4:00, and you send them a signal, they can shed 50 megawatts, 20 megawatts a load for a certain duration and then resume operations back when they get the all-clear from you guys?

MR. EUGENIS: Chairman Stafford, that's correct. So we have a number of those types of customers that have the ability to either change their operations or reduce their load for a period of time. And for commercial and industrial oftentimes you don't have the shifting aspect of it, so much as you just have an overall reduction.

CHMN STAFFORD: And what types of customers are the biggest participants in your demand response program, like, what type of industry is it, it's grocery stores, is it manufacturers, is it -- what kind of businesses are we talking about that can take a -- tone it down in the hot afternoons for you?

MR. EUGENIS: Chairman Stafford, in general, I don't want to kind of go through the specifics or name specific customers, but in general, you can see some manufacturing facilities have the ability to schedule their shifts around this. And so they may not schedule for that period of time and halt their operation for their manufacturing during that time, and then instead schedule their workers other times or just remove the shift over -- altogether.

CHMN STAFFORD: Okay. So they're getting sort of a -- they're planning ahead to shave load, it's not the Cool Rewards where they get a signal and the thermostat goes down? I think -- because Cool Rewards do it automatically and they have the option to opt out?

MR. EUGENIS: That's correct.

CHMN STAFFORD: Okay. So these guys are planning ahead, like, look, we know these are going to be big days for you guys generationwise, so we're going to shave our load during these times to alleviate some of that stress, then?

MR. EUGENIS: Chairman Stafford, typically we give them, I think it's day-ahead notice. And so system conditions are very dynamic, and it's not just when APS may have higher loads, as Mr. Cole said in his testimony yesterday, it's really dependent on the region as well. And so if you see a region-wide heat wave or resource constriction that's happening in California or throughout the West, that could also drive that need. And so we value that flexibility from our customers as well to be able to respond with a day's notice.

CHMN STAFFORD: That's what happened in 2020, wasn't it?

MR. EUGENIS: That's correct, sir.

CHMN STAFFORD: I think that was it for my -- oh, Member Fontes, do you have another question?

MEMBER FONTES: Yes. Its a question related to one of yours, Mr. Chairman.

When this thing's actually built and we compare it to PPA awards, on PPA awards that I've seen from APS, you often have cost controls. How do you implement that for a design-build when you're in charge of the costs, and it's going to be rate-based, is there similar cost controls to that of a PPA award for another PP in terms of preventing overruns or penalties for both development and construction?

MR. EUGENIS: Member Fontes, as part of the bid they do offer us a price, and there are commercial terms that apply to that price, which means that there's a damage structure that holds them to particular performance metrics to make sure that that resource comes online. And, ultimately, they're responsible for maintaining the prices they give us or being forced to renegotiate with us for the potential project.

MEMBER FONTES: And that includes them -- them being the -- who is "them" in this case, the APS team who is overseeing the construction of this for the EPC?

MR. EUGENIS: In this case, Member Fontes, that would be the EPC bidder itself. And, I apologize, I know we had some discussion on that term, but in this case the bidder is responsible for that, which is not APS.

MEMBER FONTES: So that's before it actually transfers to you that they have controls embedded in them?

MR. EUGENIS: Member Fontes, that's correct.

MEMBER FONTES: Excellent. Thank you.

CHMN STAFFORD: I think we were on slide 82.

MR. EUGENIS: Mr. Derstine, will you give me a prompt?

BY MR. DERSTINE:

Q. I took you back to slide 82, let's get you back on track. Do you want to take us forward to where you were hoping to be? I don't know if that was on analysis. You may have gotten pushed into analysis a little bit quicker than you had wanted to. But if that's the place to start or if you wanted to still cover some of your -- I think the prior one was bid compliance?

A. (MR. EUGENIS) Thank you. I think we've done a good job at this point of kind of covering both the --

Member Hill?

MEMBER HILL: One more question on analysis. I know Mr. Kryder is going to tell me that I need to speak closer to the mic, so -- forgive me, sir.

The project risk, why is technology there? You -- the project risk list that you gave us did not include necessarily a technology statement. I guess I thought technology would be in resource alignment, but under project risk, what's the technology risk you're addressing there?

MR. EUGENIS: Member Hill, that's primarily the supply chain associated with the technology, just because different technologies have different risks there, if you think about where things are manufactured.

MEMBER HILL: I just didn't want to imply that technology was generation technology that you were concerned about risk, necessarily.

MR. EUGENIS: And, Member Hill, there's an aspect of that. It's not -- it's not explicit in terms of we calculate a number associated with it. But it's our responsibility to maintain reliability for our customers, which means we're not going to contract with a technology type that we ultimately don't believe will come to fruition or won't perform to the really high standards that we have.

MEMBER HILL: Okay. And that's in that section. Okay. Thank you.

MR. EUGENIS: Okay. So I'm going -- I might summarize for a second to get me back on track here. Within the -- so we started our discussion yesterday in the Integrated Resource Plan, we talked about the needs that it's identified, it using generic pricing. Now we've used that to inform the All-Source RFP. We have the compliance stage of the All-Source RFP, where we just look to see if those bids meet the requirements of the All-Source RFP the time that we would like to have those projects in service, completeness of information.

Moving past that we get to this analysis phase where we talked about the resource alignment, the technology and project risk, the respondent risk, but mostly cost being the determining factor for when we make these evaluations. I'm going to push us to the next part of this process, which is the short-listing process.

I used an analogy earlier when Member Fontes had asked me a question about having a row of Ford F-150s standing in front of you and making a determination about which of those you might want to pursue in the future, I think that's apt for describing what we're doing as we go through and we short list different projects.

If you recall in the slide that I was previously on that showed the needs from the IRP, there's different needs that have been identified and different projects meet those needs. And when we go through the short list, we essentially line up those different projects within their technology categories, we make sure to pick the ones that bring the best benefit or the most benefit to our customers, largely weighted by cost in that calculation. And you can see the results of that process on the right-hand side screen. I have two charts here that I'd like to spend a couple of moments walking through. On the left-hand side you can see the number of projects that we short listed for these categories, with the vast majority coming from solar and storage paired together and energy storage projects that are stand-alone energy storage. This matches with that slide, I believe it was number 82 that we were on previously, that showed that we had a tremendous need for both solar and batteries on our system.

We also short listed wind projects to satisfy the need identified in the IRP, and what we anticipate will be necessary in the system, as well as demand response and then thermal projects. The Redhawk Expansion Project that we're talking about today falls into this category of thermal projects. On the right-hand side chart, you can now see the total number of megawatts associated with these and you can see it largely matches the left-hand side. The vast majority of total capacity or the nameplates megawatts of these technologies is from that solar and storage category, as well as the energy storage category.

I'm just going to briefly call out that demand response ended up being a very small portion of this RFP, in terms of the magnitude of the bid, and you recall that we were seeking, you know, approximately a thousand megawatts of on-peak capacity. And then you have our thermal resources here, which is a larger amount of nameplate capacity.

So this broadly, I think, aligns with the needs that were identified in the IRP and allows us to take the most valuable bids now and push it forward to the next part of our evaluation, which is the portfolio analysis. Taking us back to my testimony yesterday, this is the same tool that we used in the IRP. It solves for a particular reliability level a least-cost portfolio.

So we know that as we input this project-specific information into that tool, we are going to have reliability maintained in the future, and at the cheapest overall cost to our customers. That portfolio analysis is very detailed in its nature. And the key difference at this stage is that we're using the specific pricing from the bids we received instead of the generic pricing that we had available to us in the IRP.

This is the stage of the process where all of the different technology types compete against each other. All of the bids compete against each other in the portfolio analysis. And so even though the previous stage -- I isolated our comparison to like resource types, you know, all the F-150s were compared to other F-150s; if you had cars, right, all the cars were compared to other cars -- at this stage the trucks and the cars compete against each other to solve for that optimal portfolio.

That process goes through our -- our portfolio analysis, and I have what is the most complicated process diagram I'm sure many of you have seen, and for that I apologize, but hopefully we can spend some time walking through this and make some sense out of all of the different inputs and work that we're doing. And, I apologize, I wish that I had covered this yesterday as part of the Integrated Resource Plan process; however, this is the same overall process that we do in the IRP. The only difference being that the technology cost aspect of it, which you can see on the left-hand side, is generic versus in the IRP we're using those specific bids. You can see that inputs into this process vary from fuel costs to market pricing to technology costs that we discussed, as well as unit characteristics and other constraints as well.

Yesterday I talked about how we varied the price of natural gas fuel in the future. That's one of those -- one of the aspects of this that can change that ultimately solves for that least-cost portfolio. We use very similar assumptions as the IRP whenever we do this process for the RFP just with those updated bids. From the -- the kind of inputs are fed into our long-term capacity expansion modeling, that solves for that least-cost portfolio, ultimately we build that into what we call a loads and resources plan, or a L&R, and that informs our procurement and demonstrates that we maintained reliability for our customers.

CHMN STAFFORD: Member Fontes, you have a question?

MEMBER FONTES: Thank you, Mr. Chairman.

Hey, can you just touch upon how you compare, like, a battery energy storage or renewable that has no fuel cost to that of a peaker plant that does. And then financials, are you using the weighted average cost of capital of the bidder or is that some sort of other input? Where does the financials input come from and the fuel costs? Appreciate you, thanks.

MR. EUGENIS: Member Fontes, as a part of this, we include both the capital costs of the project, as well as any variable O&M cost or fixed O&M cost. The O&M being operations and maintenance cost. So it's a fulsome look at whatever expenses may be incurred on behalf of customers for a particular resource.

And so this is where the playing field is level in terms of if I have a resource that may have high capital costs, such as a renewable facility, whether that's a solar or wind facility, but ultimately very low variable O&M costs to no variable O&M costs, I'm looking at this holistically when I compare it against something that may have lower capital costs, but higher variable O&M costs.

So the modeling tool has all of those pieces available to it and optimizes for that least-cost function among the total result. We use the term "revenue requirements" often in our business, which is representative of the total cost to customers for, you know, a particular portfolio of resources. This long-term capacity expansion model estimates, essentially, those revenue requirements when making the portfolio.

CHMN STAFFORD: So to look at how it's going to affect rates then, correct?

MR. EUGENIS: Chairman Stafford, the end result is an impact to rates. In resource planning, I don't do any kind of rate-specific analysis since the Commission, and we have a rates team, kind of determine what that is.

CHMN STAFFORD: But this provides a number for them to analyze and see to take -- if you look at the total revenue requirement, this is how much money is going to have to come in to make this plant go, and then they -- you hand it off to the rates team and they figure out what they need to collect through rates to cover that, then, correct?

MR. EUGENIS: Chairman Stafford, yes.

CHMN STAFFORD: Okay. That's what I thought, but I just wanted to make sure. And then I have -- and then where do you -- where do emissions figure into this analysis?

MR. EUGENIS: The long term -- Chairman Stafford, the long-term capacity tool, and in our production cost modeling, in general, takes into account any emissions associated with those facilities. And it takes into account constraints that may be relative to those facilities.

For example, in our CEC that we're requesting today, we have a capacity factor limitation. That's part of our air permitting process. And we include that in our modeling software to say this unit can't run beyond what it's permitted to run for. And so we are able to take into account unit operation as part of our optimization.

CHMN STAFFORD: Okay. And then -- and then beyond that, the APS has its goal of being, I think, reduce your emissions -- your carbon emissions by 60 percent by 2032?

MR. EUGENIS: Chairman Stafford, our clean energy commitment is focused on 2030, and is 65 percent clean resources with 45 percent coming from renewable sources in 2030.

CHMN STAFFORD: So that's a -- you're looking at energy production, not total emissions, then, for that?

MR. EUGENIS: That's correct. The clean energy aspect of it comes from our portfolio mix of energy, includes things like demand-side technology that Member Hill identified earlier, and then the renewable energy piece of it is similar to the Commission requirement around the RES, Renewable Energy Standard, but not exactly the same. So there is some specifics to both of those calculations.

CHMN STAFFORD: And so you have built into the model, then, is it your plan to get to zero carbon emissions by 2050?

MR. EUGENIS: When we do our modeling, we don't explicitly include the zero carbon by 2050 goal. We check against the results to see that it aligns with both that 2030 goal, and then as we think about the future, we want to make sure that we're investing in technologies that have the ability to meet that no carbon goal of 2050.

We know that today's technologies don't have that ability, and Mr. Cole testified about that yesterday. We anticipate that there will be innovation in this space, and we look forward to taking advantage of that innovation when it becomes available. That may be hydrogen. It may be a different technology into the future. But we don't explicitly include, like, a zero requirement as part of our current modeling.

CHMN STAFFORD: But I'm just -- yeah, because that's kind of far out there. I'm just trying to get to -- there's -- through this process you have an eye on the ball when it comes to your carbon emissions that you're -- that you're -- as part of selecting your resources you're going to build or procure or buy power from. It's -- it's -- I think it was -- was it Hutchens, I think when he was at TEP, he had the phrase that you're on the path to decarbonation within the -- to give you the guardrails of affordability and reliability. But it's the always moving forward to reducing the carbon dioxide output, the greenhouses gases, but you can't -- you have to keep it in the realm of cost and service. I want to make sure that this model is helping you chart that path in that direction.

MR. EUGENIS: Chairman Stafford, that's absolutely correct that we look at our resource procurements and make sure that they're in alignment with our goals. We see that the renewable resources that we're procuring today are least cost. They're sources of affordable energy for our customers. We want to make sure to capture that value for our customers as well, and look forward to the future in terms of the innovation that will be available to further decarbonize the system and maintain reliability for our customers.

CHMN STAFFORD: All right. Thank you.

I see Member Little has her hand up. Member Fontes, did you have additional questions, because you -- your hand's up, I'm not sure if it went down and came back up or it's just up from before?

MEMBER FONTES: It came back up based on

your question, Mr. Chairman. And I just want to make sure that we capture for the record here, Mr. Eugenis. Can you point to where the investor tax credit, production tax credit when you're evaluating the renewables would be, and what component. I think it's part of the financials as it comes in and that's presented to you that should be in there, but, please, in your own words tell us where that is factored in, especially because APS benefits from those in some cases. I know we selected a peaker plant here, but I'm looking just to understand how the model works, for the record.

MR. EUGENIS: Member Fontes, there's a couple of different ways that you can treat those tax credits. In particular, the production tax credit, or PTC, that's associated with several renewable resources, you can treat that as a negative variable O&M associated with the resource.

For some of our PPA bids, that's captured in the price that they give APS, and so the bidder themselves is recognizing that they're going to receive that tax credit and then passing along some amount of those savings to APS and our customers as well. Those are the two primary sources of where you would see that information located as we do our evaluation, both captured in the portfolio analysis.

MEMBER FONTES: I really appreciate that, thank you.

That's it, Mr. Chairman.

CHMN STAFFORD: Thank you.

Member Little.

MEMBER LITTLE: Mr. Chairman, I have a couple of questions about the modeling process. First of all, do you use all different combinations of the RFP respondents? For example, do you combine solar one with all the different combinations of the rest of them on the different types of resources; and then solar two with all the different combinations of the rest of the resources in your modeling process?

MR. EUGENIS: Member Little, any discussion about the depths of modeling is something that makes me very excited. You can -- you can, I'm sure, quickly understand that doing a comparison one by one with the number of bids that we received and the number of short-listed projects available to us can be incredibly cumbersome. And that's what the benefit of these tools really brings us, and the fact that by kind of harnessing their ability to do an incredible amount of number crunching, that allows us to find that best portfolio without us having to do kind of a by hand or more shorthand or heuristic-based evaluation on my team. And so those tools I find to be very powerful in terms of identifying value for our customers.

MEMBER LITTLE: Thank you. As an old -- old-time utility planner, it's all these new tools are exciting to me too.

How long does it take to do that, weeks, months.

MR. EUGENIS: Member Little, I appreciate you indulging me maybe a little bit with this line of questioning. The amount -- so the complexity of the power system is increasing drastically. And the number of variable resources that we're now incorporating is driving challenges that we haven't seen in the past. And that's why it's so important to use these tools. And the modeling time frames that we've seen in some of these cases are well over 12, 15, sometimes 18 hours, using incredibly high-powered computers. I jokingly refer to them as flame-breathing computers, not a technical term, but these are essentially servers with quite a bit of memory and computing power.

MEMBER FONTES: You made your own LM6000 for some of these computers, I would imagine.

MEMBER LITTLE: And my second question is, or my third question, I guess, I don't remember reading, and maybe I just missed it, but what is the capacity factor that this -- that your proposed project is limited to?

MR. EUGENIS: Member Little, these units are going to be limited to less than 20 percent capacity factor.

MEMBER LITTLE: Thank you.

CHMN STAFFORD: And that limitation's imposed by the air permit, correct?

MR. EUGENIS: That is correct and Ms. Carlton will speak to that in more depth in her testimony.

CHMN STAFFORD: Okay. Good. So I won't ask you any more questions about the air permit.

BY MR. DERSTINE:

Q. I was just following up on Member Little's question, Mr. Eugenis, in terms of she asked about how, say, solar maybe is compared to solar, but maybe how solar as a resource and bids for solar are compared to, say, maybe this project, the Redhawk project, or maybe you have a better example, in terms of how this complicated fire-breathing computer model is used to compare those resources.

Can you give us a little more detail on that?

A. (MR. EUGENIS) Mr. Derstine, the long-term capacity expansion tool is -- excuse me, I'm trying to do this at an appropriate level for our audience here today -- it's what's called a mixed integer optimization tool, which doesn't mean a lot to, I would say, almost everybody, but it utilizes a solution process that essentially searches for the best answer, given a particular starting point in the case, and then evaluates all of the options available to it in testing for what is the best overall answer.

These are -- as I'm sure many can appreciate -- these are incredibly data-intensive problems. I've talked about how we solve for every single hour of the year, that's 8,760 hours per year. And we do it over a 15-year time period in the IRP. And so there's a tremendous amount of computing and data checking that takes place within these models in determining what that portfolio is. Hopefully that provides some depth without getting into linear algebra.

BY MR. DERSTINE:

Q. I appreciate it, and please don't go into linear algebra.

For cases like this, one of the things that we talk about that's related to the need analysis is, did you consider alternatives to the project that's being proposed? And I think what I've heard you say, but I'd like you to dig into it a little deeper, is it sounds like through the portfolio analysis, the modeling that's shown on slide 101, you did compare the Redhawk Expansion Project to other projects and other resources, like battery energy storage; am I -- am I right about that?

A. (MR. EUGENIS) That's correct.

Q. Okay. And can you give a little more color around how that happened to the model, specifically with regard to, say, Redhawk and battery storage resource?

A. (MR. EUGENIS) Yes.

So essentially what the model does is it has that list, that short-listed bids available to it. And it looks at all of those bids, and when maintaining reliability for the system, right, as we talked about over the entire year, if I have the Redhawk project and then I solve for all of my other resource needs, what is the overall cost to my customers? And then if I don't have the Redhawk project and I still have the same bids available to me and I have to backfill it with other resource types, whether that's battery energy storage by itself or a mixture of solar and storage or, you know, batteries and wind resources, et cetera, which is the cheapest portfolio.

And what we found in our analysis is that the inclusion of the Redhawk project has resulted in that least-cost portfolio, when compared to other portfolios that would have a different blend of resources.

Q. Is that the point that you're making here when I'm looking at the -- at what you have written on slide 102?

A. (MR. EUGENIS) That's correct.

MEMBER GOLD: Mr. Chairman?

CHMN STAFFORD: Yes, Member Gold.

MEMBER GOLD: To -- Mr. Derstine, to simplify this, for somebody who is obviously not as adept at this as you are, if you were to simply put up a chart, I mean, your computer comes out with this is weighted one, this is weighted two, this is weighted three, or this is dollar one, dollar two, dollar three, your computer is going to spit out a hierarchy, and you said the hierarchy with the Redhawk project and the hierarchy without the Redhawk project, correct, in layman's terms?

MR. EUGENIS: Member Gold, that's correct.

MEMBER GOLD: So it turns out that if you put the Redhawk project in, it has a much better result financially or fiscally, productionwise, it answers more questions by a certain factor than anything else that you looked at and you looked at a whole gamut of things, and the things that you had in that computer is that chart on the left, of which you have several terms up there I'm not familiar with. What is SRVM, ELCC, and L&R?

MR. EUGENIS: Member Gold, the answer to your first question I believe is yes, that there is benefits associated with having the Redhawk project outside of a portfolio that does not have the Redhawk project. Your question around the other aspects of this process diagram, such as SRVM, which is S-E-R-V-M [sic], and ELCC, which is the effective load carrying capability of a resource.

MEMBER GOLD: Well, let's go back to SRVM. S-R-V-M, I can read also, what does it mean?

MR. EUGENIS: It's a -- Member Gold, it's a proprietary software that's maintained by the Estrape Consulting Group, what it does is --

MEMBER GOLD: Okay. So that's the program used, okay, got it. ELCC again?

MR. EUGENIS: Effective load carrying capability.

MEMBER GOLD: Okay. And L&R?

MR. EUGENIS: L&R is a load and resources document.

MEMBER GOLD: Okay. So all of that stuff came with a portfolio output analytics, which gave you a score for Redhawk. How much more efficient, in terms of dollars was the Redhawk -- to accomplish the goals that you put in there -- was Redhawk than its nearest competitors -- competitor or competitors?

MR. EUGENIS: Member Gold, I'd have to go get that information for you.

MEMBER GOLD: Just ballpark, if you remember offhand, is it very much better or a little better?

MR. EUGENIS: Member Gold, it drives significant value for our customers. I'd have to get you an exact value. And when we perform this analysis, it doesn't always kind of give you that, like, what is the next and the next and the next that's available, it's solving for the best one. And so by having it included in the portfolio, I know that this is a part of the best portfolio for our customers.

MEMBER GOLD: So this is the best one which you're recollecting is a significantly best one compared to anything else?

MR. EUGENIS: That's correct, Member Gold.

MEMBER GOLD: Thank you. That's what I needed to know.

CHMN STAFFORD: Thank you. We are -- we have been going for approximately 90 minutes. I know the court reporter can use a break. So before we go to recess, Mr. Derstine, it looks like you have something to ask?

MR. DERSTINE: Well, I think, Mr. Eugenis, am I right or wrong that you are ready to wrap up your testimony and if you -- if you're not ready and we don't have a -- just a short piece then we're going to take a break, but if you want to put a nail in it.

CHMN STAFFORD: I have a couple more questions for him, so --

MR. DERSTINE: Oh, you do? Well, then, we're going to take a break. Thank you, Mr. Chairman.

CHMN STAFFORD: Okay. Let's take a 10- to 15-minute recess.

We are in recess.

(Recessed from 10:32 a.m. until 10:53 a.m.)

CHMN STAFFORD: Let's go back on the record.

Mr. Eugenis, I had a couple of quick follow-up questions for you. For the RFP that -- that the -- that this project was a winning bidder on, how many other projects were selected as part of that RFP?

MR. EUGENIS: Chairman Stafford, we're still in negotiations with projects for that, so I don't have a final count for you yet. We have contracted with a number of bidders. I don't have an up-to-date number, but I could get you what we've contracted for thus far if you're interested.

CHMN STAFFORD: Yes, please, thank you.
Mr. Derstine.
BY MR. DERSTINE:
Q. Mr. Eugenis, do you want to -- I think you've taken us to the end of your discussion on the All-Source RFP, do you want to give us your wrap-up of that topic and whatever else you'd like the Committee to understand about your testimony today?
A. (MR. EUGENIS) Yes. Thank you, Mr. Derstine.
To -- as a summary, to kind of briefly review some of the topics that I've covered in my testimony, we use the Integrated Resource Plan to identify the different needs that we have for resources on the system. That informed our 2023 All-Source RFP process. We used similar tools throughout this process in identifying these different projects, that long-term capacity expansion tool that I've kind of brought up several times in our -- in my testimony thus far. And we find that the Redhawk project is a part of that least-cost reliable portfolio for our customers.
There was one other aspect of the RFP that I did want to bring up that I -- I neglected in my previous testimony. I just wanted to add that we do have an independent monitor that participates as part of the All-Source RFP process. This is somebody who evaluates

the evaluations that we do to make sure that we are doing them in a fair and consistent basis and gives us a report at the end of that kind of confirming that the process was performed in a fair and equitable manner. And that was something that I neglected to mention earlier.

CHMN STAFFORD: Member Little, you have a question?

MEMBER LITTLE: Yes.

What are the qualifications of the independent monitor? This is all pretty sophisticated stuff to understand.

MR. EUGENIS: Member Little, I would have to get their resume, for lack of a better term, or their qualifications for you. I don't have that available to me right off the top of my head.

MEMBER LITTLE: Generally speaking, do you -- do you know if they have experience in resource planning or --

MR. EUGENIS: Member Little, they represent many years of industry experience, in both the resource planning and procurement spaces. The independent monitor that we worked with most recently has several different members that participate as part of the process, one of which has several decades of experience in the utility industry.

MEMBER LITTLE: Wonderful. Thank you very much.

BY MR. DERSTINE:

Q. Mr. Eugenis, do you use an All-Source RFP to select your independent monitor?

A. (MR. EUGENIS) No, we do not.

Q. Anything else? I see your summary slide, number 105, you've spoken to it. Anything else you wanted to add on -- on your topics?

A. (MR. EUGENIS) In conclusion, I'd just say that we've identified a durable need for these resources into the future. I spent some time talking about that in terms of the Integrated Resource Plan and the study work we performed there. There's a lot of value to this resource type, the dispatchability of it, the flexibility that it brings to our grid, and that we find this to be a valuable project for our customers in making sure that we maintain reliability into the future.

Thank you for your time today. And I appreciate any other questions you may have for my testimony.

Q. I'll -- before the break we had a couple questions that I -- that you said we would make an effort to follow up on, one was Member Fontes's question concerning I think the accounting treatment of this project and that is that, if I understood Member Fontes's question, would it be -- whatever label you're putting on the document you sign with the counter-party to build the Redhawk Expansion Project, would -- is it eligible for treatment as CWIP, and maybe -- I think, Mr. Cole, you're the right person to speak to that issue.

A. (MR. COLE) "The right person to speak to that issue" is probably going a step too far, Mr. Derstine. But I will do my best. In the case of Redhawk, just maybe to try to shed a little bit of light on a couple of questions that were asked previously, the project itself is an EPC. And so in this particular case, we are making payments along the way. And so I think Member Fontes's question about CWIP, my belief is, yes, there will be CWIP involved as that goes forward. I'm not an accountant. I never played one on TV, but I believe that's the way it works. And so -- just if that helps a little bit with the description. And as far as SRB goes, we believe that this project will be eligible for SRB. Our estimate for this project is to be in service in 2028.

We are not eligible to be able to file a SRB and collect on anything unless it is in service, and at this time we do not know if and how and when we would file that SRB filing. So I think that answers most of the questions wrapped into one. Member Fontes and others who were part of the line of questioning, I hope that helps a little bit.

MEMBER FONTES: It does. Thank you, Brian. I appreciate that. I just want to make sure that we state for the record that this will eventually be a rate-based project, so appreciate it.

CHMN STAFFORD: Thank you.

MR. DERSTINE: Anything further for Mr. Eugenis before we move on to Mr. Van Allen?

(No response.)

(Peter Van Allen was previously sworn by the Chairman.)

BY MR. DERSTINE:

Q. All right. Mr. Van Allen, you're sworn, you're under oath, but let's go back to your introduction slide and -- well, I guess we moved on to a new phase of our case. We're done with the deep thinkers about planning and resources, and we're back to a guy who is involved with building the project; is that about right?

A. (MR. VAN ALLEN) That's correct.

Q. Okay.

A. (MR. VAN ALLEN) I get the privilege and responsibility of the project once it's selected for that process.

Q. Let me have you move forward to your microphone and make sure the court reporter can hear you and the members of the Committee.

A. (MR. VAN ALLEN) Is this better?

Q. That's better. Thank you.

A. (MR. VAN ALLEN) Very good.

Q. Take us through your education and your work experience, please.

A. (MR. VAN ALLEN) Okay. Very good. So first of all, good morning, and thank you for this opportunity. We're excited to be here. A lot of work to get to this point in a project that's been selected.

So a little bit about me. My name's Pete Van Allen, I'm a project manager at APS. And as a project manager I have responsibility that includes oversight of scope, of schedule, budget, the risk, the quality, and the resources for the project, right. So it's pretty encompassing.

How did I get here? Actually, that jumped -- there you go, my background -- so my background a little bit. Graduated from ASU, studied at W.P. Carey School of Business. I have a degree in supply chain management. I also have a certification with the Project Management Institute, which is a PMP, project management professional.

My experience at APS started 14 years ago. And that experience includes a background in procurement, operations, supporting daily plant operations at a coal plant, maintenance activities, planning, you know, planned outages, forced outages, there to support day-to-day activities. Also capital projects which are investment in new systems, right, to keep plants going. So that's my background where I started with APS.

Eventually got into more of a consulting role on larger complex projects and transferred into actual project management leading the execution of projects and having direct oversight. So that's my background.

Q. Okay. As the -- you're the project manager for the Redhawk Expansion Project?

A. (MR. VAN ALLEN) I am the project manager for the Redhawk Expansion Project, that's correct, yes.

Q. As the project manager, you have a multitude of responsibilities, I think as you just touched on, but one of them is to -- you're responsible for overseeing the preparation and the filing of the CEC application that brings us before the Committee today; is that right?

A. (MR. VAN ALLEN) That is correct.

Q. Okay. And the application is marked as APS Exhibit 1?

A. (MR. VAN ALLEN) That's correct.

Q. Okay. Have you had an opportunity to review the

application that was prepared and filed by APS?
A. (MR. VAN ALLEN) Yes, I have.
Q. Do you have any corrections, changes to the application, as we sit here today?
A. (MR. VAN ALLEN) I have none at this time.
Q. Okay. Well, let's, then, you have up on the screen the outline of the testimony, the topics that you're going to cover for the Committee. Let's take us through that and preview what we're going to hear from you today.
A. (MR. VAN ALLEN) Absolutely. So I want to walk through the existing plant that's there today, cover the history, right, of that plant, the plant description, how it's configured and what that plant is today, its location. Then I'll get into the actual expansion project that's sited at that existing facility, the type of equipment being proposed, the technology, the benefits it provides. And then, ultimately, end with some project costs and schedule and then we'll have other panelists that will speak to environmental studies that were conducted and air experts, water experts, right, that can answer detailed questions in that space, so --
Q. Okay. So start us off with an overview of the existing Redhawk Plant. I mentioned in my opening that the plant was sited and constructed in the early 2000s,

why don't you give the Committee some more detail and background on the Redhawk Plant as it sits today?

A. (MR. VAN ALLEN) Will do.

So the screen on the right, this is in APS-11, slide 114. This is a representation of approximately where the plant resides, both in the state of Arizona and Maricopa County. So the figure on the right -- wrong button, here we are -- all right, the figure on the right is the state of Arizona, and that star represents generally where the plant resides in Maricopa County. I think we've had a little bit of a preview of that in the opening by Mr. Derstine. And then Maricopa County, unique shape here --

MEMBER KRYDER: Excuse me, Mr. Van Allen, would you speak into your microphone a little closer, please?

MR. VAN ALLEN: Will do. Thank you, Member Kryder.

MEMBER KRYDER: Thank you.

MR. VAN ALLEN: The plant resides 50 miles west of the city of Phoenix, city center. So western Maricopa County.

Okay. So the CEC for the existing plant was approved in February of 2000. That plant was originally approved for four units to be built.

Ultimately only two units were built at the Redhawk Power Plant. The two plants that are built are combined cycle units, and they're a little bit of a different technology than a simple -- just a simple cycle combustion turbine.

The CEC approved those four units. The total output was 2,120 megawatts, but ultimately, only two were built so that the capacity of the existing station today is 1,060 megawatts. Those units are fueled by natural gas. That natural gas is provided by two -- two different sources at that station. You have the El Paso Gas Line, and there's also the Transwestern Gas Line.

And that -- that allows our resource management team to take advantage of sometimes there's a pricing difference between the two sources of gas, and they -- our customers can ultimately benefit from -- from that station having two sources.

CHMN STAFFORD: And those two sources would be the San Juan Basin and the Permian Basin?

MR. VAN ALLEN: That is correct. The Permian Basin being Western Texas and the San Juan Basin being basically the Four Corners region.

CHMN STAFFORD: Which one is which for pipelines?

MR. VAN ALLEN: So El Paso is the Permian

Basin and the San Juan is through the Transwestern pipeline.

CHMN STAFFORD: Thank you.

MR. VAN ALLEN: Yeah. So the existing plant is approximately a 460-acre property, and the existing plant consumes about 200 acres of that property. And as we look at the screen on the right, we had the visual flyover, but the Redhawk Plant is kind of in the center here. It is surrounded by solar fields on the north, the south, the east, and partially on the west.

Directly to the west of the Redhawk Plant is the Mesquite Power Plant, as was presented in the visual flyover previously. And then you also have the Arlington Valley Power Plant, which is also a natural gas power plant further to the west, approximately two and a half to three miles away. And there's an additional solar field that's west of that Arlington Plant. And then north -- north of the Redhawk Plant is the Palo Verde Nuclear Generating Station.

The power plant's composed primarily of equipment, infrastructure you would typically expect of a power plant, right, there's buildings, structures, power generation equipment, electrical infrastructure, motor control centers, power distribution centers, equipment necessary to generate electricity for customers.

As spoken to previously, the station does have two sources of gas, which is a benefit. There's water that is -- there is two wells on the property that exist today that provide groundwater, and then there's also water that's provided to the existing facility from the Palo Verde Nuclear Generating Station.

MEMBER KRYDER: Mr. Chairman?

CHMN STAFFORD: Yes, Member Kryder.

MEMBER KRYDER: Question, Mr. Van Allen. What's the difference, in pedestrian terms, between the new generators that are being proposed here and the combined cycle? Can you say that in a few words that a layman could understand?

MR. VAN ALLEN: When you say "pedestrian," is that like a visual if you're --

MEMBER KRYDER: No, that's like me that doesn't know anything except the light switch on the wall.

MR. VAN ALLEN: The differences between the existing units and the units being proposed?

MEMBER KRYDER: Right. Between the proposed units and what are called here combined cycle.

MR. VAN ALLEN: Certainly.

MEMBER KRYDER: What I'm trying to get at is, you were authorized -- or this was authorized --

Redhawk was authorized for four units, only two were built, there must be some underlying reason why two were not built, and does that lead us into the two that are being proposed? That's where I'm headed.

CHMN STAFFORD: Okay. I can answer that, Member Kryder. When they originally sited this plant, Arizona was considering electric competition, deregulation, to where the generation aspect -- because you have generation, transmission, distribution -- the generation portion was going to be deregulated.

After the debacle in California in 2000, Arizona abandoned that and, in fact, they just changed the statute, I believe it was last year or the year prior, to remove the reference in the statute that competition is the policy of the state. And most of the rules the Commission passed -- well, a good chunk of the rules regarding electric competition got thrown out by the Court of Appeals in the Phelps Dodge Decision in 2004.

The CECs, they have a time frame to build, 5, 10 years, it depends, typically the ones we do have a 10-year limit, but they varied in the past between you know, five years, I think less in a few cases, but these plants -- a lot of these plants, I think, were built in contemplation of competing in the market to provide power. And then when that failed to materialize, they didn't fully develop. So that's why they only built two of the units that were authorized. And I'm sure by now, under the original CEC, it's expired for them to build those two combined cycle units. And so what they're proposing here is eight --

MR. VAN ALLEN: Eight LM6000s --

CHMN STAFFORD: -- Eight LM6000s, which are a smaller simple cycle, as opposed to combined cycle. I think we talked -- I think there was testimony in the last case we talked about, like, a combined cycle takes six hours to go from full stop to full running, whereas these units take 10 minutes.

MR. VAN ALLEN: That is correct. That is correct.

MEMBER KRYDER: Thank you very much. That's very helpful.

MR. VAN ALLEN: Thank you, Chairman Stafford.

All right. Advancing to the next slide, so I'm now on slide 120. This is a zoomed-in version of the aerial photo. And I just want to walk you through the existing power plant. You have an administration building, which includes some electrical infrastructure in that building, there's a control room for the power plant in that building. There's also the plant management team that supports the operation and maintenance for that facility that reside there. The facility includes a building for the planning and maintenance department. Planners and maintenance personnel reside in that building, it includes a warehouse as well for indoor storage for the existing plant. You have a RO water treatment facility in the bottom right, with water storage tanks that provide water to the plant processes.

You also have an outdoor storage facility on the property, and then you have the actual units themselves, which is Redhawk Unit 1, Redhawk Unit 2, and I think it's important, I'll talk about the expansion project here in a minute, but the existing units are 530 megawatts per unit. The units we're proposing for the expansion project are 49.6 megawatts, and that's in the optimal conditions when it's, like, a 40-degree ambient condition outside. They derate, right, as they get warmer, ambient, right, 115-degree day it derates approximately six megawatts.

So the existing plant, as we say, combined cycle, it's really you have a simple cycle turbine on the front, it just has a -- what they call a HRSG, on the back end, so as the combustion turbine is operating, you have the exhaust gas coming out of the back of that turbine at approximately 1,100 degrees. That heat goes through the HRSG, it's a fancy word, heat recovery steam generator, it's a boiler, right, a bunch of pipes inside this big metal box with pipes that can take advantage of that heat that it would otherwise just go out the stack.

And that heat makes steam. Steam can be fed to a steam turbine and can turn another turbine generator that captures that energy and converts it to electricity for customers. So they have a better heat rate. They're more efficient, but they also take six hours. And depending on the load that the resource management team is trying to cover, in some instances it a combined cycle plant makes sense.

When you have renewables and the benefit of some of the newer emerging technologies, they can -- they can deploy other -- other technologies, right, that are better for customers. But we still can provide some reliability backup generation with a simple cycle plant that can be online in 10 minutes. And I'll talk about that more as we advance, but --

MEMBER GOLD: Mr. Chairman?

CHMN STAFFORD: Yes, Mr. Gold.

MEMBER GOLD: Mr. Van Allen, you seem to have a great deal of knowledge of these plants, so I'm going to ask you some questions, if I might, before we go further. Yeah, I'm trying to pull it closer, or maybe I'll just get closer. Sorry about that.

In that storage facility and in the main plant, you have control rooms that control your generators, start them, stop them, or do you control the generators from actually the generators? First question. How do you turn them on, where do you have to be?

MR. VAN ALLEN: Absolutely. So in the administration building there's a control room where a control operator sits at a station that is outfitted with all the right controls, and there are screens that provide them indication of status of the different systems. For that -- for each respective unit.

MEMBER GOLD: So the control room is really the brains of the whole operation?

MR. VAN ALLEN: With -- there's a human machine interface, so there are personnel that are monitoring the machine very closely.

MEMBER GOLD: But they tell it to start and stop or you can tell it to go autonomously, but whatever it is, that's where the start and stop comes from?

MR. VAN ALLEN: That is correct.

MEMBER GOLD: Next question, the switches that control the start and the stop, are they very expensive?

MR. VAN ALLEN: It -- so the answer to that is it depends. There's different voltage classes, different size of switches, small pumps, right, really small equipment can be very nominal value. There's other high-voltage equipment that could have a very real value.

MEMBER GOLD: Are these switches turned on manually or are they turned on electronically?

MR. VAN ALLEN: They are turned on electronically through a control system that, in some cases, you can initiate a start sequence and there's automation behind the process, and it will initiate certain systems to come on. In some cases they -- certain systems are turned on manually by the -- by the operators.

MEMBER GOLD: So the operator can always override it and turn on the systems manually?

MR. VAN ALLEN: That is correct, yes.

MEMBER GOLD: Is that like a mechanical switch or is it an electronic switch that turns them on?

MR. VAN ALLEN: They do that at the HMI interface, so it's on literally a monitor that's in front of them, and they have a mouse and they can select to turn things on or turn things off.

MEMBER GOLD: Okay. That's understandable, but what I really want to know is can an operator go over to either the combined cycle or the simple cycle generator and just turn it on without using any electronic equipment?

MR. VAN ALLEN: I don't know the answer to that question. But I don't believe it's feasible to just go turn on. It's not as simple as a light switch. There are multiple systems that have to be in certain status to go to the next sequence, and they're very complex systems.

MEMBER GOLD: So let's take a look at a worst-case scenario.

MR. VAN ALLEN: Okay.

MEMBER GOLD: That we're relying on your station and something's gone on and your electronics don't work. Can you go in there and turn this thing on, under a worst-case scenario, and get power onto the grid?

MR. VAN ALLEN: I don't know the answer to that question. There are certain -- certainly systems you can turn on manually, but there are some that have permissives that are -- specifically hold you out from initiating so you don't create an unsafe condition.

MEMBER GOLD: Okay. So let me make it simpler, and there's a reason I'm asking.

MR. VAN ALLEN: Okay.

MEMBER GOLD: Forget about your combined cycle, I understand they're very complicated to turn on because you've got to get temperatures reached, you've got to get steam turbines to go on. Let's go to your simple cycle plant that you're planning on building. Simple generators, the LM6000 turbines, it's got an on-and-off switch, doesn't it?

MR. VAN ALLEN: Even though they're called simple cycles, they still have very complex controls that monitor, you know, the combustion process, everything's optimized to perform in concert, right, the emission control system has to work with the combustion turbine. You're flowing gas at the right rate, you're maintaining pressure. There's a lot of electronics involved for normal operation.

MEMBER GOLD: Is there a way to turn on those generators without electronics? Can you turn on the generator like you start a jet airplane?

MR. VAN ALLEN: No, not without electronics. You need electronics.

MEMBER GOLD: Okay. What electronics do you need?

MR. VAN ALLEN: There are multiple systems that make that system work. There are what they call PLCs, process logic controllers --

MEMBER GOLD: Okay.

MR. VAN ALLEN: -- that control the processes, right? There's certain sequences, there's logic that is integrated into those controllers that ensure things are started in the right sequence at the right time at the right speed before switches turn on, close.

MEMBER GOLD: So the PLC, project logic controller, is the key ingredient that if that thing burns out you can put another one in and start the generator?

MR. VAN ALLEN: And pull -- pull module, yeah. It has logic programmed into it and it follows its program.

MEMBER GOLD: How many backups do you keep?

MR. VAN ALLEN: So there's an assessment that would go for this project that's proposed, right, we identify a list of all the different components that make up a power -- power block or a unit, and we would go through a thorough assessment with the maintenance planners and the plant personnel and some engineering team members that would make recommendations that certain -- certain spares are kept in the storeroom.

MEMBER GOLD: So the PLC you have backups for?

MR. VAN ALLEN: We've not made that decision at this time for these units.

MEMBER GOLD: Before you go on, how expensive is a PLC?

MR. VAN ALLEN: I think it depends on the component of the PLC, but if you -- just the controller I'm speculating, but probably anywhere from 10,000 to $50,000, depending on the controller module.

MEMBER GOLD: Okay. 10,000 to $50,000 for the controller module. So let's assume the grid goes out, which has happened before. I was in Boston when they had the big blackout, and that was caused by something. And a couple years after that they had another power blackout. What I'm asking is, can your LM6000s be started in a worst-case scenario?

CHMN STAFFORD: You're talking like a black start?

MEMBER GOLD: I have no idea what the terminology is called, it may be that.

MR. VAN ALLEN: And so I don't believe these units are being configured for black start operation. Typically, that configuration you have to have some power to spin certain systems up, right, you have diesel generators that would come up to allow other systems to come on that are mandatory so you can give it -- give it the start, and it can run through its start sequence. So this station is not currently being configured to be black start capable.

MEMBER GOLD: Okay. But you do have small diesel generators there just in case of something, right, backup generators?

MR. VAN ALLEN: So for the proposed project we're not --

MEMBER GOLD: No, for the existing project.

MR. VAN ALLEN: For the existing plant? I'd have to find out what backup generators they have at the facility. I anticipate they have some. I can make a note and get a question to that or get an answer to that question.

MEMBER GOLD: I would appreciate an answer to that. So the terminology -- thank you, Mr. Chairman -- I'm looking for is a black start and the critical component to make that work is a PLC, but you also need some kind of small diesel generator to provide enough power to use that; am I correct?

MR. VAN ALLEN: That's a correct statement.

MEMBER GOLD: Is there anything else that I'm missing because I don't have enough knowledge.

MR. VAN ALLEN: No, no, I would say we have black start units in our fleet, and they are very specific -- they are strategic units that are used and selected and there are policies and procedures that they put in place, so that if we ever had a blackout that there is a way to restore power.

MEMBER GOLD: Okay.

MR. VAN ALLEN: And we have experts and I'm not an expert in that case.

MEMBER GOLD: No, you've given me a lot of information I didn't have previously. So the black start project for APS, I mean, there's, what is it, 5 million people in the state -- in Phoenix -- or the state of Arizona that you guys supply?

MR. VAN ALLEN: We have 1.4 million.

MEMBER GOLD: 1.4 million. I come from New York, forgive me, it's 14 or 20 million by now.

CHMN STAFFORD: But that 1.4 million customers, it's not 1.4 million people. It's per connection.

MR. VAN ALLEN: I may be one customer at APS but yeah, there's four people in the house.

MEMBER GOLD: Well, 1.4 million customers and you have enough black start to provide electricity to those 1.4 million customers and this plant will help or won't help?

MR. VAN ALLEN: So --

MEMBER GOLD: In that scenario, what you're planning.

CHMN STAFFORD: Well, I think the black start doesn't -- that's just to get the system back up. If there's -- if there's an outage, and so then once that outage happens is that these units would be incapable of running until you had the black start unit fire up and give enough juice to restart this plant. And I don't think this plant plays any role in the black start. It's just primarily designed to serve load.

The combined cycles, they provide more of a steady output, whereas the project is going to be multiple smaller units that can come on and off in sequence, depending on what the demand is. And so they can quickly ramp up if there's -- if there's a need to increase the supply, and then they can ramp down when it's -- that demand is no longer there.

MEMBER GOLD: So this project is for reliability under normal circumstances, but not under emergency circumstances?

CHMN STAFFORD: That is my understanding.

Is that correct?

MR. VAN ALLEN: That is correct. I believe Mr. Spitzkoff will be able to talk in more detail later in his testimony if there's questions in this space.

MEMBER GOLD: Thank you very much. And, Mr. Chairman, thank you very much.

CHMN STAFFORD: Member Fontes, I see your hand is raised.

MEMBER FONTES: Yes, Mr. Chairman. I just was not following the suitability and applicability of those questions. I think our admin rules and our procedures focus on environmental stakeholders on the design-build and not the operational capabilities. I think NERC covers that, so just want to observe that maybe we should stay a little more focused here, Mr. Chairman.

CHMN STAFFORD: Thank you for that observation, Mr. Fontes.

Mr. Derstine.

BY MR. DERSTINE:

Q. Have you covered what you planned to cover about the existing Redhawk Plant, Mr. Van Allen?

A. (MR. VAN ALLEN) I have.

Q. Okay. I had one additional question that I see your third bullet on slide 119 says, "Water source from Palo Verde Generating Station and local groundwater," can you give the Committee a bit more information on, one, how water is sourced from Palo Verde, and then if you have the numbers in terms of how much the existing

Redhawk Plant currently uses in the way of groundwater, just on an average basis?

A. (MR. VAN ALLEN) I'd be happy to.

So the existing Redhawk Plant does have water coming to it from the Palo Verde Plant, that is effluent water, right, treated, reclaimed wastewater that they get from municipalities in the western -- western valley, and Palo Verde being in such close proximity to that station, the Palo Verde station has the ability to receive water. They have the agreements in place, and the great thing, it requires less groundwater, right, you can use that treated effluent water.

The existing plant today at Redhawk uses approximately 500 acre feet annually in groundwater. And the expansion project that we're here discussing today will use an additional approximately 300 acre feet of groundwater.

Q. What are the groundwater rights, if you know, that are held by APS for the Redhawk Power Plant site?

A. (MR. VAN ALLEN) So my recollection, and Mr. Nicholls will speak about this in greater detail in the studies that he conducted, there are 3,356 acre feet of groundwater rights, type I groundwater rights.

Q. So that's the certificated water rights that APS received when it developed the 400-plus acre Redhawk

Plant site?

A. (MR. VAN ALLEN) Yes, that's correct.

Q. Okay.

MEMBER KRYDER: Mr. Chairman?

CHMN STAFFORD: Yes, Member Kryder.

MEMBER KRYDER: Mr. Van Allen, you mentioned that, in addition to groundwater, I just wanted to clarify, did I hear correctly that some of the water for Redhawk existing comes from Palo Verde?

MR. VAN ALLEN: That is correct, yes.

MEMBER KRYDER: And is that included in the 500 acre feet that are currently being used or is the 500 acre feet in addition to what comes from Palo Verde?

MR. VAN ALLEN: The 500 acre feet is in addition to what comes from Palo Verde.

MEMBER KRYDER: Okay. So --

MR. VAN ALLEN: The reason --

MEMBER KRYDER: Oh, go ahead.

MR. VAN ALLEN: There's a distinct difference between treated wastewater and groundwater, right, from an environmental impact, so we differentiate. And being that the expansion project is not proposing to use wastewater from Palo Verde, we focused solely on the groundwater use.

MEMBER KRYDER: Okay. And the wastewater

that comes from Palo Verde is wastewater in the sense that it's their -- out of their cooling towers?

MR. VAN ALLEN: So the cooling towers -- okay. So the water that comes from Palo Verde is through their water reclaim facility, which has a treatment process for that water. They improve it to a specific grade or quality.

MEMBER KRYDER: Sure.

MR. VAN ALLEN: It comes over to the Redhawk site at a specific or defined quality.

MEMBER KRYDER: Okay. And so what existing Redhawk uses has to be groundwater rather than that reclaimed water or the -- it's just the new proposal that has to use groundwater instead of reclaimed water?

MR. VAN ALLEN: So, Member Kryder, I'll do my best to explain the different uses of the water. The water that comes from Palo Verde at the Redhawk site is used in the cooling towers at the Redhawk facility, the existing facility.

MEMBER KRYDER: Okay.

MR. VAN ALLEN: The expansion project that's being proposed does not have cooling towers.

MEMBER KRYDER: Right.

MR. VAN ALLEN: Because they're simple cycle units. So they don't have a need for cooling towers. So -- but they do have a need for water in different processes for the new units. And it's much more efficient and cost-effective to use groundwater for the limited water needs for the expansion project.

MEMBER KRYDER: So the water on the proposed units is demineralized RO water?

MR. VAN ALLEN: That is correct.

MEMBER KRYDER: And what's the approximate efficiency of your RO units? Back of the envelope.

MR. VAN ALLEN: You know, I don't have the exact efficiency number. I will get that information for you. But as you understand it, you know, there is some percentage of waste drain, right, when you create RO water, right, you have a permeate, and you have a --

MR. KRYDER: Your effluent, sure.

MR. VAN ALLEN: Right. And that is -- but that water can be returned to the existing Redhawk Plant and used in other processes.

MEMBER KRYDER: Oh, okay. That was where I was also driving the question. The effluent, then, that comes from your RO process goes back into the existing Redhawk and is used somewhere in that process, because that's sometimes kind of nasty stuff; is -- is that a correct statement?

MR. VAN ALLEN: That is a correct

statement.

MEMBER KRYDER: Okay. So you don't have a de-sal pond -- or a pond where you dump your effluent or anything like that, you can use it back into the existing plant?

MR. VAN ALLEN: The existing plant has -- has a ZLD, a zero liquid discharge unit, right, that can process water. But they always try to -- they follow all the rules, all the permitting requirements, to use water to the exact requirements --

MEMBER KRYDER: Okay.

MR. VAN ALLEN: -- that comply with the water standards. And Mr. Nicholls will speak to that, right, he will talk about the Arizona -- it's an active water management area, and they follow rules and our plant has permits in place, and we follow those permit requirements.

MEMBER KRYDER: And does each of the new units, they are, what, 10, 10 new units coming on or proposed?

MR. VAN ALLEN: So eight new units being proposed, right, with the two existing units, so the site, if approved and fully built out, would be outfitted with 10 units.

MEMBER KRYDER: And so does each unit have a chiller, then, as a part of its use and that water is used in the chilling process or how do you use the water on the proposed units?

MR. VAN ALLEN: I have a slide, I think, where I'll be able to better explain.

MEMBER KRYDER: Oh, okay. If you're coming up on that.

MR. VAN ALLEN: I will, yeah, on a later slide.

MEMBER KRYDER: Okay. Great.

Anyway, I was just wanting to look at that, because water is water and we're in an ag area, and everybody around you is in an ag area, and so anything -- every -- every gallon we take out takes away from some other usage, and that's where I was looking.

Thank you very much. I'll look forward to the presentation.

MR. VAN ALLEN: Okay. Thank you.

BY MR. DERSTINE:

Q. I guess on that, following up on Member Kryder's point in terms of other water users, my understanding is that when the Redhawk Plant was originally sited, there is a -- the land use permit that was part of that required that APS monitor nearby wells and ensure that there were no adverse impacts to those nearby wells; am I

correct about that?
A. (MR. VAN ALLEN) That's correct.
Q. And that's something that APS does on an ongoing basis?
A. (MR. VAN ALLEN) Yes. We have a water resource team and they participate and have oversight for that -- that responsibility, that condition requirement.
Q. So to close the loop on water with regard to the existing plant and the proposed expansion project, you're using treated effluent from Palo Verde for many of the water needs at the existing combined cycle plant. In addition to the effluent from Palo Verde, you're using approximately, depending on the year, 500 acre feet of groundwater for the existing combined cycle plant; is that correct?
A. (MR. VAN ALLEN) That is correct.
Q. And for the expansion project you anticipate an additional need of approximately 300 acre feet of groundwater for those eight new simple cycle units?
A. (MR. VAN ALLEN) That is correct.
Q. Okay. So do you want to take us further into your description of the expansion project?
MEMBER FRENCH: Mr. Chairman?
CHMN STAFFORD: Member French.
MEMBER FRENCH: Before we move on, I have

one question about the groundwater situation. I understand that you have certificated authorities pertinent to the land that will cover your need, but you mention that you have two wells on the property that will serve these authorities, and I just want to ensure that those wells have a permitted volume associated to them that can cover your need. And if you can't answer this question, it would be better answered later, that's fine too.

MR. VAN ALLEN: That is correct. Mr. Nicholls will speak to that, but we do have two existing wells. They will provide the water necessary to meet our need for this expansion project.

MEMBER FRENCH: Okay. So the question is, do those wells have a permitted capacity that will cover that need?

MR. VAN ALLEN: I'll let Mr. Nicholls answer that.

MEMBER FRENCH: Thank you.

MR. VAN ALLEN: Yes.

MR. DERSTINE: And if that's not information that Mr. Nicholls has in terms of the permitted volume for the two wells at the existing Redhawk Plant site, we can get that information and we'll update Mr. French on that, is that -- can we do that, Mr. Van Allen?

MR. VAN ALLEN: I'll work on that if Mr. Nicholls doesn't have that information, yes.

BY MR. DERSTINE:

Q. Okay. All right. The expansion project.

A. (MR. VAN ALLEN) All right. So this is just a ground-level photo of the existing units at the facility for your reference. We'll move on. So we're going to cover the expansion project. So the -- so just to orientate everyone, I think this is consistent with the placard you have as a placemat, but this image gives an outline of the existing plant boundary. This is the 460-acre property, right, outlined in blue. And the project site is being proposed within that yellow box on the existing property.

So the expansion project's ultimately proposing to build and construct eight LM6000 units. These units are rated at 49.6 megawatts when you're in a 40-degree ambient condition. We are permitting these for less than 20 percent capacity factor. And the units are natural gas-fired. And they are equipped with advanced state-of-the-art emission control system, which is ultimately a CL catalyst, they call it an oxidation catalyst. It converts carbon monoxide to CO2, so it's a safe -- much safer than carbon monoxide, and it's also equipped with a SCR catalyst system. In conjunction with ammonia it converts that NOx to -- to nitrogen and reduces that pollutant to levels that are acceptable.

MEMBER GOLD: Mr. Chairman?

CHMN STAFFORD: Yes, Member Gold.

MEMBER GOLD: Mr. Van Allen, you passed over something very quickly, I'm sure it's something I don't understand. But the previous two slides you show the existing Redhawk units. There seem to be four stacks, but you said there were only two generators.

Why are there four stacks.

MR. VAN ALLEN: Great. Yeah. So jumping back to slide 122 on APS-11, so as mentioned previously, the existing units are what they call a two-by-one combined cycle power plant. And the addition of a HRSG on the back end of a simple cycle unit really makes it a combined cycle unit, right. You're taking that waste heat that's coming out of the turbine, you're making steam. And that steam is fed into a steam turbine that has a separate generator and it can make additional power. And a two-by-one combined cycle power plant is a configuration that ultimately has two combustion turbines, with two HRSGs, and both HRSGs feed into a common steam turbine for a combined output of 530 megawatts of output.

MEMBER GOLD: So if I understand the picture correctly in front -- I'm going to use a pointer for just a moment. That gadget and that thing are the steam turbines or the steam turbine and the HRSG?

MR. VAN ALLEN: I understand your question. I'll walk you through that diagram.

MEMBER GOLD: Okay.

MR. VAN ALLEN: Yes. So on the very front of the unit there's a -- it's kind of a blue-colored box, that's the air inlet for the combustion turbine. It's a filter house. It simply has the filters that clean air before they go into a combustion turbine, much like an automobile has an air filter. And in some cases they're also equipped with an evaporative cooler. You can do inlet fogging or you can even put a chilling system, right, in that housing, and it cools ambient air coming in to the combustion turbine for efficiency in hot ambient conditions.

So it -- then you have the combustion turbine that is coupled directly to an electric generator, and it creates electricity. That waste heat comes out the combustion turbine into -- this is what they call the HRSG, the H-R-S-G, it's essentially just a boiler. It has a lot of steel tubes, pipes, and their boiler -- boiler tubes that have water flowing through them, and it creates steam.

So when we say a two-by-one combined cycle power plant, that simply means you have two combustion turbines, and that "by one" is a steam turbine, so they have a common steam turbine that they both can feed steam into and create electricity. So in the case of Redhawk, these are 160-megawatt-rated combustion turbines, GE 7FA units.

MEMBER GOLD: And there were two of them?

MR. VAN ALLEN: There are two of them.

MEMBER GOLD: One for the first two stacks --

MR. VAN ALLEN: For unit -- unit one, right, has two combustion units. And then unit two has two combustion turbines.

MEMBER GOLD: Gotcha. So even though it looks like four things, there's really only two turbines --

MR. VAN ALLEN: The two by -- yeah, the two-by-one combustion.

MEMBER GOLD: -- going through boilers of some sort to create steam, which turns something to generate, turns --

MR. VAN ALLEN: As -- the steam turbine is coupled to another separate stand-alone electric generator that creates electricity.

MEMBER GOLD: Gotcha. Like a steam engine creates mechanical energy, that thing -- some kind of dynamo that creates electric energy?

MR. VAN ALLEN: Yes, that's correct.

MEMBER GOLD: Thank you.

CHMN STAFFORD: Member Fontes, you had a question?

MEMBER FONTES: Thank you, Mr. Chairman.

My question has to do with load efficiencies, startup times and flexibility of operations, because this is a peaker plant, you stated that you got a two-by-one configuration with the HRSG. Talk to me about higher fuel consumptions, increased emissions, and then environmental benefits. I also want to know how the ramp-up period would be different from a simple cycle on LM6000s versus this configuration, and why you are going to operate that. And then also we have to deal with the lifecycle on this Committee and look at the operational efficiencies over time. How is the HRSG, the maintenance of that and the control systems, a greater burden over a simple cycle for a peaker plant?

In all of the other cases we looked at here in Arizona and certainly the plants that I'm familiar with in my past in building CCUTs, peaker plants have not been employing HRSGs, they've -- they've been simple cycles. So that's the context of where I'm coming from and why that particular design is being opted for here.

So if you can elaborate on that, Mr. Van Allen, and I know I gave you have a bunch of stuff to do, but again, it's the flexibility of the operations, the maintenance, and the efficiency and the fuel use.

Thank you.

MR. VAN ALLEN: Member Fontes, I appreciate your question. I think I might have confused the panel when I -- we had started going into the expansion project, then we came back to the existing plant, and I think that's important to note. The picture on the screen currently is the existing station, which is a combined cycle power plant. The expansion project being proposed are simple cycle units that do not have HRSGs and their ramp times is very different.

MEMBER FONTES: Excellent. Can you characterize and compare that? I thought that's what I had heard, but that's why I was asking the question delicately here.

MR. VAN ALLEN: Certainly.

MEMBER FONTES: Just for the fellow members, hey, you've got an existing power plant that is going to be operated differently, so therefore, the environmental attributes are going to be a little bit different with the fuel utilization. So, again, trying to get it back to the applicability of what we're going to look at when we get to the environment to have you set that up.

So thank you.

MR. VAN ALLEN: Yeah. So, Member Fontes, I would answer the existing combined cycle units from the time you give them a start to the time they're at full baseload can take hours. And you have to condition steam before you can start spinning up the steam turbine. It takes time. Mr. Eugenis and Mr. Cole gave testimony previously that spoke to the need for more peaking generation, which can respond very quickly to fluctuations that could result, you know, from a various number of factors, right, if the wind quits blowing, clouds come rolling through and you lose solar generation, peaking units can respond to that. And they can be dispatched with a full load within 10 minutes. So I think that's a key differentiator between peaking units that are LM6000 simple cycle relative to a traditional combined cycle power plant.

MR. DERSTINE: Did that answer your question, Member Fontes?

MEMBER FONTES: I think so. What I'm

trying to gather for my fellow colleagues here on the panel is that this operation will be -- have less environmental concern than the original, so the expansion is less of an impact, and it's not an extension, per se, in terms of load efficiency and potential environmental impact.

Is that fair to say, Mr. Allen -- Mr. Van Allen, sorry?

MR. VAN ALLEN: That is a correct statement. And I think you draw on a very important part of the testimony that I want to convey, is that we're adding eight units, right, to a site that has two units it sounds like a significant, large number, but these are small aeroderivative units, right, and the combined capacity of those eight units is only 75 percent of one of the existing combined cycle units. But it creates huge flexibility for the resource management team, because you can dispatch them in 25-megawatt blocks, right, and that's a real flexibility tool that provides reliability.

MEMBER FONTES: Thank you, Mr. Chairman.

CHMN STAFFORD: Thank you.

MR. VAN ALLEN: Thank you.

So now I'd like to talk about the proposed expansion project. It takes advantage of existing infrastructure that exists, right, you can site plants on an existing power plant with an existing plant operation maintenance team that have the training, the capability skill-sets. You have infrastructure, gas infrastructure. You have electrical infrastructure. There's water infrastructure. It just -- it checks a lot of boxes that provide value, right, the value proposition for APS customers. And I think that's important.

BY MR. DERSTINE:

Q. So, Mr. Van Allen, I think the point you're making there is this: If APS -- if a project proposal came through the All-Source RFP and it was to develop eight new LM6000 peaking units at a new undeveloped site, you would have to bring in the gas infrastructure, the transmission infrastructure, all of the common plant elements that are already existing at the Redhawk Plant site and so by, I guess to use Mr. Eugenis's terminology, there was an opportunity, because of all the infrastructure that exists at the Redhawk Plant site, to develop these new eight simple cycle units without having to incur the costs and to develop all that other common plant that otherwise would be required for this project?

A. (MR. VAN ALLEN) That is a correct statement.

Q. Okay.

A. (MR. VAN ALLEN) So now I'd like to walk through, we're on APS-11, slide 128, and we're zooming in now to the primary construction area for the proposed expansion project, right. The yellow box outlines the siting location for the eight new units, along with a switchyard addition that's necessary.

And Mr. Spitzkoff will be speaking to the switchyard addition in great detail, but the generating assets are here on the eastern side or the right side of the expansion area. And it includes units 3 through 10, and there's some necessary infrastructure, right, some tanks and systems required to support the operation of these units that is also necessary.

The units share a common transformer and there will be some other photos later that will give you a more realistic representation of these proposed facilities. But, ultimately, the eight units will tie into what's called a 230kV collector bus. And that collector bus will take the power and then there's a 230 to 500 step-up transformer, which will bring the voltage up to the 500kV level, 500,000 volts, that is ultimately -- has a gen-tie into the switchyard addition as a point of interconnect.

And we'll cover that in much greater detail, but that's -- that's a general representation of the facility. So the units will be sited directly south of the existing admin building and maintenance buildings, this is the area where Redhawk's Units 3 and 4, if they were originally built, would have been sited.

Q. And that hashed area, and I'm looking at your slide or the diagram in slide 128 of APS-11, that hashed area, I gather, is the expanded switchyard that will be developed to serve the new simple cycle units that we're proposing for the -- for the project?

A. (MR. VAN ALLEN) That is correct. And right now we're proposing to build it out with the necessary bay to interconnect. And by extending it, it has the ability to service other potential interconnectors in the future if and where needed.

MR. DERSTINE: Okay.

CHMN STAFFORD: Member Fontes, you have a question?

MEMBER FONTES: I do. Just a point of clarification for my background here.

Is the step-up transfer -- transformer in the 500kV line shared between the two, the existing CCTG and the peaker plant, or will it have a separate step-up transformer at the peaker plant?

MR. VAN ALLEN: Yup. Member Fontes, the 230 collector bus will have a dedicated transformer for the expansion project, and it's independent of the existing plant facilities.

MEMBER FONTES: And then the way it will be dispatched, does the -- onto the transmission at the 500kV, I assume that's a 500kV line that it's going to be exported at for both plants, the POI?

MR. VAN ALLEN: That is correct, yes. The Redhawk Switchyard --

MEMBER FONTES: That is sufficient capacity that both the baseload plant for the CCGT, plus the peaker plant could export through the POI or would the baseload have to curtail if the -- if the peaker plant is fully exported?

MR. VAN ALLEN: Member Fontes, Mr. Spitzkoff will have great testimony, great detail, and he has -- he has the right background to answer those questions.

MEMBER FONTES: No problem. I didn't know if that was you, but I'll wait for Mr. Spitzkoff. I just, again, want to understand that because we're talking systems reliability what's the available transmission capacity once it gets out to the grid to just provide additional support to what you guys have provided for the previous hearings and witnesses.

Thank you.

MR. VAN ALLEN: Understood. Thank you.

All right. So now I'd like to talk a

little bit about the Title V air permit. So the existing plant has a Title V air permit, it's permitted through Maricopa County, right, and EPA ultimately has oversight, but Maricopa County is the local authority.

And the expansion project is -- we've submitted a permit application to revise that Title V air permit, and Ms. Carlton will speak to that in great detail later in her testimony. But that -- that's in the works, that's been applied. We submitted that in April.

We talked briefly about groundwater use -- the other pointer here. Just a moment here. Okay. So we talked briefly about groundwater use in earlier testimony. The plant does have the existing water rights necessary, and Mr. Nicholls will speak to the ground -- the wells themselves. The LM6000s, I think it's important to note they are optimized for reduced water use, right, they use what's known as a fin fan cooler. It's essentially, they're metal fins that have fans, and they can use air to cool, as opposed to having a, like, water air-type cooler, so it uses less water. And the expansion project will use an estimated 300 acre feet annually for groundwater.

BY MR. DERSTINE:

Q. Before you move into the technology of the LM6000s, I think Member Kryder had asked a question about whether or not these units were using chillers and I -- can you speak to that?

A. (MR. VAN ALLEN) That's a good question. So I think the best way to describe that is getting into that next slide where --

Q. Your technology section?

A. And I think it gives me a visual reference so I can help the Committee members understand a LM6000. So the figure on the right is from APS-11, it's slide 132, and it's an expanded version -- or view of a LM6000 turbine. They're relatively -- they're complex, but there's a few module components to them. I can walk you through the machine.

So you have, at the inlet, this is the inlet guide veins, right, that are kind of -- they can control the flow of air into the machine. They can angle at different loads. They have optimal position for controlling the air into the machine. This is what's known as a low-pressure compressor, and that spins at nominally 3,600 rpm.

And then you have what's called the VBVs, the variable bleed valves, which during startup to maintain flame stability, those valves can open up so you're not pushing too much air through the machine and blow out the combustion process that's underway. You have a 14-stage high-pressure compressor that compresses air to a higher pressure that's necessary for operation and the combustion process.

Going to the combustor, you have the high-pressure turbine, which there is a two-stage high-pressure turbine, followed by a low-pressure turbine, which has five stages. And then the combustion process goes out. So the power, right, you have the combustion process that takes place, the power's captured here by the power turbines, and ultimately, the low-pressure turbine powers the low-pressure compressor, and there's a drive shaft on the front end that connects directly to an electric generator that creates the electricity for the LM6000.

So it's a relatively simple configuration. It's not much bigger than a 12-passenger van. They are small units relative to the larger frame units that the existing plant is composed of. Those larger units, right, don't have the turn-down capability that a smaller unit has and provides.

So as far as water use, there's really three processes for water use on a LM6000. You have what's known as inlet -- you can do cooling, you want to cool the air coming into the turbine, when it's really hot out, you get better efficiency by cooling that air, and you can either do inlet fogging, which is like misters, right, like if you go to movie theaters and they have the misting system out, right, that's kind of the equivalent of inlet fogging. You can also do evap coolers, which is -- it's kind of like a swamp cooler, they have a media where you can run water down that media, air comes through it, it cools the air. Or you can do what they call a chilling system, which is a closed-loop system. It's chilled water, just like in large buildings, you can have a chilled water system that cools -- cools rooms, right, and has a heat exchanger.

There's pros and cons to the different types of inlet cooling you can provide. For simple configuration, inlet fogging, which are the misting, are a low-cost solution, and you get the same, you know, close to the same benefit, but at a much lower cost.

CHMN STAFFORD: And the purpose of all those is to increase the efficiency or the output of the unit in high ambient temperatures, correct?

MR. VAN ALLEN: That is correct.

CHMN STAFFORD: And there's another process that you use water for on the other end for reducing emissions, correct?

MR. VAN ALLEN: That is correct, Chairman Stafford.

CHMN STAFFORD: Am I jumping ahead, is that the next note in your slides?

MR. VAN ALLEN: No, you're right, I'm just kind of walking through the machine and -- so the systems are equipped with what they call a WSPA, it's power augmentation water spray. You can also inject water at the inlets of the machines at the low-pressure compressor. And that system puts more water, increases the air density. By the time you get to the combustion process, you've regained efficiencies you otherwise wouldn't have if you did not inject water at that part of the process.

MEMBER KRYDER: Mr. Chairman?

CHMN STAFFORD: Yes, Member Kryder.

MEMBER KRYDER: Perhaps you're going to cover this, Mr. Van Allen, you said there were three possibilities for this particular engine, which is it going to use or does it use any of three according to the operational needs?

MR. VAN ALLEN: Member Kryder, that's a good question. So these units are -- that we're proposing to build are equipped with inlet fogging capability.

MEMBER KRYDER: So the answer to my earlier question about chillers is "No, we don't use them."

MR. VAN ALLEN: This facility will not be equipped with a separate chilling system.

MEMBER KRYDER: Thank you.

MR. VAN ALLEN: Thank you, Member Kryder.

And as Chairman Stafford alluded to, the final use of the water in the machine, so you have the inlet foggers, you have the water spray power augmentation feature that injects water as a second source of water use, and then the third is in the combustion process there's what's called NOx water, and that is used to temper the combustion process to reduce the amount of NOx that is generated in the combustion process. So it controls emissions. It helps reduce the emissions.

MEMBER KRYDER: And this is all RO water?

MR. VAN ALLEN: Yes, that is correct.

MR. DERSTINE: Mr. Van Allen, is this a good place to pause in your discussion about the generation technology; and, Mr. Chairman, is this a good place to pause for the lunch break?

CHMN STAFFORD: Seems like an excellent place to me.

Mr. Van Allen, is this a good stopping point for you?

MR. VAN ALLEN: It's a great point.

CHMN STAFFORD: I think it's a great stopping point for everyone in that case.

With that, let's take our lunch recess. It's 12:05, let's come back at 1:10.

We stand in recess.

(Recessed from 12:05 p.m. until 1:10 p.m.)

CHMN STAFFORD: Let's go back on the record.

Mr. Derstine, I believe you were wrapping up with -- oh, no, you weren't wrapping up, you were continuing on with Mr. Van Allen.

MR. DERSTINE: I think we're close to wrapping up with Mr. Van Allen. He's going to cover just, I guess, spend another few slides just giving the Committee his final discussion on the LM6000 turbine, and then he's going to move into his discussion of the project schedule and budget, and then I think we're ready to transition on to the next witness, so --

MEMBER KRYDER: Mr. Chairman?

CHMN STAFFORD: Yes, Member Kryder.

MEMBER KRYDER: A question for Mr. Van Allen, if I could.

CHMN STAFFORD: Certainly.

MEMBER KRYDER: You've got eight units proposed in this project, correct?

MR. VAN ALLEN: That is correct, Member Kryder.

MEMBER KRYDER: And I -- is it correct to assume that you can start them one at a time or you can start two at a time or four at a time? Tell me what the plan is on these, as far as the startups and use.

MR. VAN ALLEN: Sure. Member Kryder, that's a great question. And I defer to Mr. Eugenis to answer that question. The resource management team kind of leads the way the units are operated most efficiently for the fleet, yeah.

MR. EUGENIS: Member Kryder, we'll dispatch the units just according to system need. It may be one unit at a time or we may dispatch multiple of them. It's just whatever we need to at that point in time, whatever the system calls for.

MEMBER KRYDER: And the number of units that you'd start off, let's say instead of all eight, you start at four, they'll start in the same 10 -- in other words, they would all switch on and be up and running in, back of the envelope, 10 minutes? I mean, it's not a function of the number that you try to start up, you don't have to sequence them and start 1 and then 10 and start 2 and start 10, or they can start all at once?

MR. EUGENIS: Member Kryder, I believe they can start all at once, but I'll defer to Mr. Van Allen to correct me if that's not correct.

MR. VAN ALLEN: Member Kryder, it's a correct statement that you can dispatch all eight units, if called upon and needed immediately, or you could call on one if you only needed one unit.

MEMBER KRYDER: Thanks very much. That was much appreciated.

MR. VAN ALLEN: Thank you.

BY MR. DERSTINE:

Q. I think you were just going to walk through -- you had a couple slides showing different photo images of the units.

Do you want to just quickly cover those?

A. (MR. VAN ALLEN) Right. So since this is LM6000 technology, I think the Committee's very familiar, there have been recent projects, they've been well educated on LM6000s. But slide 136 is a photo of a LM6000 in a shop environment being serviced by a technician. It just gives approximate scale to the approximate size of the turbine, its complexity, its general configuration.

The next slide, this is slide 138 from APS-11, this is a photo representation of a LM6000 power plant. This particular plant has six units. Just walk you through the units. So -- get the laser pointer turned on here -- so at the top of each respective unit you have a filter house, that's the air inlet where the air goes in, comes down into the turbine package and air's fed into the turbine and it's creating the electricity, right, as it's directly connected to the generator.

The engine's operating, the emission control system's on the back end of the unit, which is called the SCR duct, and that's where the catalyst systems reside that can control the emissions. And then this particular image, this is a plant in the Houston area, so it has a lot of greenery, very different environment from the Southwest.

The stacks on these particular units are only 65 feet in height. Our units proposed for the Redhawk Expansion Project are 85 feet in height. Each unit has a step-up transformer that steps up the power from 13.8kV to 230kV voltage. There's also a demin water tank here in the back of this particular plant that holds the demin water that's used during operation of the units.

There are also other tanks associated with the water tanks, raw water and other -- other necessary tanks for the balance of plant systems.

Q. I think your next slide is a similar photo of a representation of a plant in a different location, anything unique or different about that?

A. (MR. VAN ALLEN) There is not. It's, you know, it also shows the air inlets with the stacks. You have a cable tray that have different instrumentation and control cables that run to -- to the units from various plant infrastructure to support the functionality and the operation of the units.

Q. Okay. Does that conclude, I think, your coverage of the LM6000 technology?

A. (MR. VAN ALLEN) That does conclude.

Q. Okay. Let's move on to the schedule and the budget. I think we're just advancing the right slide without bringing the left along for the ride.

A. (MR. VAN ALLEN) Yeah, I apologize if a button --

Q. Now I think we're at the end. Jumped too -- we'll fix it in the control room over here.

A. (MR. VAN ALLEN) Okay. So then, okay, here we are. Project schedule and budget. So we'll be moving on to discuss the project schedule. So the first -- the plan is that the first units will start up in the fourth quarter of 2027, with the final units being in service in spring of 2028. And that's part of the plan to be ready for summer of 2028.

Construction's approximately a 24-month duration. There's approximately 100 to 125 personnel that would be supporting the construction operations of this facility. The capital cost estimate for this project is $443 million. And that's comprehensive of the entire plant, the electrical equipment, switchyards, gen-tie lines, and substation addition necessary to integrate the system to the ultimately what's known as the energy management system, so that it can be called upon to service APS customers.

The benefits with this project, there's no additional cost to obtain land, it's existing property. And APS owns the sites and, as we discussed previously, has infrastructure to support power generation. And we're currently still in ongoing negotiations with an EPC contractor to sign the agreement to move forward with the project, so --

Q. All right.

A. (MR. VAN ALLEN) And just a look-ahead. So we're here in August of 2024 -- use this -- so on the screen on the left -- get the highlighter -- so we're in August 2024, here in the Line Siting Committee, we anticipate at some point in October we would possibly be in front of the Commissioners for approval -- this pointer is not working for me -- and then construction beginning in 2025 through 2027, and ultimately in service in 2028. So that's a high-level review of the overall project schedule.

And I'd just like to close with my remarks that, you know, these are -- this is an important project. It's a relevant project. It's a necessary project. And the benefits are it puts power on the grid at a key location that will provide reliability for APS customers. We plan to be in service in summer of 2028. That's a -- we have our work cut out for us, right, to do that in kind of a post-COVID environment, we work very hard to deliver and maintain schedule on projects of this magnitude, but we're committed to that.

And I appreciate you hearing the high-level review from a project scope and schedule perspective. And turn it over to you, Mr. Derstine.

Q. Thank you, Mr. Van Allen.

Any additional questions for Mr. Van Allen?

CHMN STAFFORD: Member Hill?

MEMBER HILL: Thank you, Mr. Chair.

APS has a commitment to zero emissions by 2050. I know it's a voluntary commitment. I know that that's your goal. What's the life expectancy of this plant?

MR. VAN ALLEN: Member Hill, that's a good question, and I think --

MEMBER HILL: Great question number three.

Sorry.

MR. VAN ALLEN: -- my resource management team is best suited to answer -- answer that question.

MR. EUGENIS: Member Hill, we use a book life associated with these facilities of 35 years, however, that's just a generic assumption that we use. Ultimately, it's set by the ACC as part of a depreciation hearing.

MEMBER HILL: So is it -- when I think about the lifecycle of this plant as we're siting it, thinking about the environmental impacts, including emissions, is it conceivable that in 2050 this is decommissioned, but we're still paying for it? If it's a 35-year depreciation process.

MR. EUGENIS: Member Hill, we anticipate that there will be some innovations into the future of technologies that will allow us to continue to use facilities, such as the one that we're requesting today as part of our hearing, and that will still align with our goal in 2050.

MEMBER HILL: So you're thinking a different kind of fuel that might be carbon neutral or carbon capture on the stacks or something like that or are you thinking it's a whole -- a whole new genera- -- like a whole new -- what are you thinking?

You guys are doing the innovation, so I'm thinking that you're thinking longer term, so what does that look like?

MR. EUGENIS: Member Hill, those are some options. So it could be hydrogen fuel that is a potential in the future. I'm not sure what -- it depends on what happens with that particular technology. It could be something like carbon capture or sequestration into the future. Could be something entirely novel that doesn't exist today.

I think the purpose of making that commitment public was to signal to the industry that there needs to be that innovation that takes place over the next couple of decades.

MEMBER HILL: And I just -- I'm concerned about stranded assets. I know that we need this electricity now. I do understand that. And I do understand that we're in a transition. I -- I'm wondering what options we have -- I just don't want to get to a situation where it's 2050, APS has made its commitment, you're getting there, and then we're paying for this project, and it's a stranded asset. That's -- that's my concern.

And I don't know how you guys are thinking about treating stranded assets. If you have strategies around that, it would be nice to know.

MR. EUGENIS: And, Member Hill, absolutely a topic of discussion internal to APS, something that we're very focused on is our assets into the future. And I think it's going to really depend on the present circumstances at that time, in terms of what we will ultimately do with these units that we're talking about today, and frankly, the rest of the fleet that we currently operate that has carbon emissions.

So really dependent on innovation to take place, for future technologies to come to fruition, and then ultimately doing what's best for our customers and maintaining reliability at least cost for them.

MEMBER HILL: Okay. Thank you.

CHMN STAFFORD: Member Fontes, you have a question?

MEMBER FONTES: Yes, sir.

Before this CEC and the Transmission Line Siting Committee, we've seen a few peaker plants lately. I tend to track overnight construction costs. And we've seen them range from 950 to 1,300 per kilowatt hour. If I did the math correctly, this one's 1,115, kind of on the higher end, but, of course, you know, supply chain, long lead items, I get that. I guess, going to Member Hill's effect, two questions: One is, can you tell us what that is in terms of an overnight construction cost in terms of kilowatt -- per kilowatt; and then on the EPC, can you just go on the record and confirm that you have liquidated damages and scheduled damages for cost controls for that.

And then the question that I have, independent of that, separate from the overnight construction costs, when we get to the appropriate time, because we look at the lifecycle of the asset and the environmental mitigation, towards Member Hill's question, what is the decommissioning plan, and how will that be funded? Or -- it would be something that I want to look at later today or when we get to the appropriate section. If you could follow up with that, either yourself or Mr. Derstine, I would appreciate that.

Thank you.

MR. EUGENIS: Member Fontes, I'll follow up with you on what the dollar per kW cost was for the plant. I don't have that immediately in front of me. I can confirm that there will be liquidated damages or commercial terms in place that guarantee performance as part of any contract that's signed for this facility. And then we'll follow up in terms of a future decommissioning plan as well.

BY MR. DERSTINE:

Q. And, Mr. Van Allen, I think we heard some of the

Committee's discussion with the applicant last week on decommissioning. I think you indicated that APS has a generalized decommissioning program or obligation that you recognize, we can go into -- unless you have the knowledge to answer it now, we can come back to that or can you answer that question?

A. (MR. VAN ALLEN) Mr. Derstine, I don't have the specifics on that program, so I'd have to talk to my subject matter experts in that space, and we can get a response to the Committee.

Q. Okay. Very good.

CHMN STAFFORD: Mr. Derstine, I believe you're going to call Mr. Spitzkoff next?

MR. DERSTINE: Yes. That concludes Mr. Van Allen's testimony, the last witness.

CHMN STAFFORD: Mr. Spitzkoff is all lined up. I guess I can swear him in and --

MR. DERSTINE: Swear him in and Ms. Benally will -- has the privilege and the honor of presenting Mr. Spitzkoff's testimony.

CHMN STAFFORD: Excellent. Thank you.

Mr. Spitzkoff, do you prefer an oath or affirmation?

MR. SPITZKOFF: Affirmation, please.

(Jason Spitzkoff was duly affirmed by

the Chairman.)

CHMN STAFFORD: Please proceed.

JASON SPITZKOFF,

called as a witness on behalf of Applicant, having been previously affirmed by the Chairman to speak the truth and nothing but the truth, was examined and testified as follows:

D I R E C T E X A M I N A T I O N

BY MS. BENALLY:

Q. Thank you.

Good afternoon, Mr. Spitzkoff. Let's start with an overview of your educational background and work experience.

A. (MR. SPITZKOFF) Okay. It seems this needs to be elevated.

I have a bachelor's of science in electrical engineering and a bachelor of arts in economics, both from Rutgers University.

I've been working in the industry for 23 years at APS, all roles involving transmission planning, siting, and interconnections. Currently the manager of transmission planning, siting, and interconnections.

For industry background, I have participated in national forums as a part of the NERC Planning Committee, NERC is the North American Electric Reliability Corporation. In a regional capacity, in various WECC committees, which is Western Electric Coordinating Council. And more regionally in WestConnect on the Planning Management Committee. And then locally, participated in a number of the State of Arizona's biennial transmission assessments and testified in a -- more than a handful of line siting cases.

Q. Okay. Thank you.

What do you plan on covering in your testimony today?

A. (MR. SPITZKOFF) Today I plan to cover three main topics: The first being the transmission infrastructure in the surrounding area of the Redhawk project. And then part of that, how the Redhawk Expansion Project is connecting to the grid. Then move on to the Reliability Study that APS filed. And then talking about the interconnection process and the current status of the interconnection requests for this project.

Q. Okay. Thank you for that overview.

So let's start with you describing what the transmission system is in the area, and I think you've got a map that you're going to work from, which is APS-11, slide 157.

A. 158.
Q. 158. Thank you.
A. (MR. SPITZKOFF) Yeah, so first going to describe how Redhawk -- the existing Redhawk is connected to the grid. And on the right screen, I'll provide some orientation to the map. At the top is the Palo Verde Generating Station, and then where all the red lines converge, that's the switchyard. And, as Mr. Cole accurately explained yesterday, it's sort of to the east of the major plant equipment.
Moving to the south is the Hassayampa Switchyard where you can see a large set of transmission lines converging in that location. And then down at the bottom is the existing Redhawk Power Plant.
So the two generators at Redhawk today connect to the Redhawk Switchyard that's there today. And then from that switchyard, Redhawk is connected to the Hassayampa Switchyard by two 500kV generator tie lines. And that's shown as the two blue lines that I'm tracing out here. And just to orient to the map also, I color-coded the transmission lines in red and the generator tie lines in blue, just to differentiate between lines that are just connecting generators to both Hassayampa and Palo Verde, as opposed to transmission lines that leave Hassayampa and Palo Verde switchyards to

the greater system.

And as you can see, Hassayampa connects to the Palo Verde Switchyard via three 500kV lines. So those switchyards are closely tied together. And then overall, those two switchyards make up a very important transmission hub in the western grid. They have -- there are nine 500kV lines that leave those two switchyards, and then between both of them there's over 10,000 megawatts of various types of generation connected there, and that's nuclear, natural gas, solar, battery storage, all -- all connected there.

Q. Mr. Spitzkoff, you said two switchyards, and you have I think nine lines that you believe -- I'm sorry, that I believe I heard you say that emanate, what are the names of the two switchyards?

A. (MR. SPITZKOFF) The Hassayampa Switchyard and the Palo Verde Switchyard. This is the Palo Verde Switchyard. This is the Hassayampa Switchyard. And relative to this discussion, the Redhawk Switchyard is connected to Hassayampa. And Hassayampa -- that's how it's connected to the larger grid.

CHMN STAFFORD: Member Fontes, do you have a question?

MEMBER FONTES: Yes. I just wanted to ask him if he could add some additional detail on this.

And I always appreciate your participation, so thank you for being here again. Can you talk to who owns the physical structures on those circuits? And then on the circuits that the power's going to be exported for specifically on the peaker plant, that circuit, who owns the capacity? Because, as you probably can articulate better than me, sometimes capacity rights on the circuit are shared, and I just want to make sure we have a clear understanding of how that's going to be exported for the record.

Appreciate you.

MR. SPITZKOFF: Sure. I'll go into that explanation here. As far as the first part of your question, who -- who owns the facility. So APS owns the Redhawk Switchyard and the two tie lines that go to Hassayampa. The various lines that leave Hassayampa, the transmission lines, have a number of different owners. Almost all of them, or probably all of them, actually, are jointly owned by many different entities, APS, SRP, California utilities, a whole host of entities own various parts of all of the nine transmission lines out here. SRP is the operating agent for Hassayampa Switchyard.

So -- and then I think you asked about capacity. Between the two tie lines that go from Redhawk to Hassayampa have more than enough capacity for the addition of the Redhawk expansion generation, the existing Redhawk gas peaker plants. And there's also a solar plant that's connected to the Redhawk Switchyard too.

So all -- all of those plants, there's more than enough capacity in the tie line to get to Hassayampa for all of that generation. And then between all of the transmission that leaves Hassayampa and Palo Verde, there's transmission to get that generation to where APS needs it to go.

MEMBER FONTES: Is that going to cross a single circuit up into Palo Verde or a double circuit as it's shown on the right?

MR. SPITZKOFF: There -- so from -- from Redhawk, it's two individual lines that go to Hassayampa. And then Hassayampa has four transmission lines that leave Hassayampa itself, and then three lines that go to Palo Verde. And then Palo Verde has an additional set of lines, probably five additional 500kV lines. All of those 500kV lines are single circuit.

MEMBER FONTES: So it can go out a number of circuits, it's not limited to one circuit? If you had an outage on one circuit, you could still operate the peaker plant across other circuits?

MR. SPITZKOFF: Yes, we can operate the peaker plants, the existing plants, yes.

MEMBER FONTES: Great. I appreciate that. That's exactly what I needed.

Thank you.

BY MS. BENALLY:

Q. Mr. Spitzkoff, thank you for walking through the existing transmission system. APS will have to connect the energy that's generated from the expansion project to the electric grid; is that right?

A. (MR. SPITZKOFF) That is correct.

Q. Would you describe the facilities that are required to execute that interconnection?

A. (MR. SPITZKOFF) I will.

Mr. Van Allen laid some of the groundwork for this. I'll talk from the slide on the right. As you saw from Mr. Van Allen's slides, you could see the eight additional peaker generators, the LM6000s lined up on the right side of the graphic there. You could see in front of them each -- each pair, two of them connect to a generator step-up transformer. That takes it on the high side of that.

This is the 230 collector, that is represented by the line running in front of all those plants. Then from that 230 collector, it goes to the step-up transformer. That's from 230kV, 230,000 volts, to the 500kV. And to connect it to the Redhawk Switchyard, we do have to expand the existing Redhawk Switchyard down into this area, and that's shown by the solid blue line.

To add one bay for that connection, the switchyard -- the existing switchyard up here, in order to connect the plant we have to add the -- an additional bay out here. But what you can also see are the dashed lines that are -- that are shown here. That just shows the future layout as we plan a new switchyard or an expansion of an existing switchyard, we like to take a guess at what the future use of the switchyard is, what the future size would be, so we can most efficiently lay that out.

So you can see it here. It's basically a mirror image of what's on top. The top has eight terminations. This expansion is really the -- will end up being the same size. So we just need the first bay for this project, but it lays out the future growth that could -- if we have future transmission lines that need to connect here or future generation interconnection requests, you could see there's room where we can add on the additional bays when needed in the future.

Q. And, Mr. Spitzkoff, the hatched area is identified as the switchyard siting area. Am I correct in stating that that whole area's identified as the siting area to allow design and engineering flexibility and that the switchyard could go anywhere within that location?

A. (MR. SPITZKOFF) Yes. So there's two reasons for that -- for the hashed area being a little bit larger than what you see covering the blue lines here. One is when you get into the specific engineering of the actual site, you get into the soil conditions, the geotechnic studies, what you -- the placement of -- you see the facilities here, well, it may end up having to be shifted further to the south a little bit, because of whatever existing conditions might be out there.

The other reason is, while we would plan this for these eight new terminations, in the future there could end up being more terminations that request connection here. So if we don't have to push down for engineering reasons, this actually leaves a little bit more room for even more bays in the future. As long as our reliability studies show that we can handle additional interconnection in a reliable manner, it provides that room.

Q. I believe now you're ready to move to the next topic, which is regarding the Reliability Study; is that right?

A. Yes.

CHMN STAFFORD: One second.

Member Fontes, you have your hand raised?

MEMBER FONTES: Yes, sir.

I -- just a couple of clarifications on my end. So is this cost associated with this going to be covered by the peaker plant is question number one? And then, two, assuming your colleagues filed for an interconnection request, was this a series or cluster and where are they at in terms of phases, phase I, do they have a systems impact study, phase II, or do we actually have costs in a phase III at this point?

MR. SPITZKOFF: Certainly. Member Fontes, on your second question, I will get into much greater detail on the interconnection requests and current status, so I'll hold that answer for a minute.

The first question on the costs, the -- what you see in the solid blue, so the bus section breakers, the bus extension, and the new bay, all -- that part of it would be called network upgrades. So that's handled by the transmission provider. And that's standard per the FERC interconnection process.

The actual gen-tie line, the portion that's the gen-tie, so from this portion all the way back to the facility is sole cost of the generation project. So the -- the Redhawk Expansion Project would pay that cost, and it's not part of the overall network cost.

MEMBER FONTES: So just when we get to the overnight construction costs, I just want to know if that cost is included in the peaker plant for total construction on the EPC. Just so we capture that for the record. Thanks.

BY MS. BENALLY:

Q. When APS filed its application for the certificate that's before the Committee today, were we required to perform a Power Flow Study?

A. (MR. SPITZKOFF) Yes.

Q. And did APS conduct that study?

A. (MR. SPITZKOFF) The APS generation team onboarded a consulting firm to perform a Reliability Study.

Q. And was that included in APS's 90-day filing for this project?

A. (MR. SPITZKOFF) Yes, it was.

Q. So can you walk us through the Reliability Study that was performed?

A. (MR. SPITZKOFF) I can. So that study was performed by a consulting firm hired by APS to basically mimic a full-blown interconnection study. So it performed a reliability analysis that covered two different types of analysis. First part was steady state analysis, so that's a thermal and voltage assessment. Is the addition of this project going to overload any wires or create any bus voltage violations.

The second part of that study is called a transient stability analysis, and that studies the impact of the grid in the immediate aftermath of a system event. So it's a very short-term assessment of the reliability of the system. The steady state is more once -- once the system reaches a new equilibrium. Both phases of those studies showed no adverse impacts and no -- and, hence, no network upgrades that would be required due to the addition of this expansion project.

MEMBER GOLD: Mr. Chairman?

CHMN STAFFORD: Yes, Member Gold.

MEMBER GOLD: When you say a system event, Mr. Spitzkoff, what do you mean?

MR. SPITZKOFF: Sure. If there is a breaker failure, a transformer failure, if there is a line-to-ground event for -- and what that means is one example is if a tree contacts a wire and that creates a path to ground, so that's a fault in the system. And there could be a number of events that would create that. So any time there's a fault in the system, we do an assessment of the response of the system to make sure the response is within the reliability criteria.

MEMBER GOLD: So a lightning strike?

MR. SPITZKOFF: Lightning strike could be a triggering event. Generally, the system has protection against major effects of a lightning strike, so each -- our transmission lines, especially extra-high-voltage generation lines have static wire on top of the line, so if you're driving past a large transmission line, sometimes you'll see a really -- a much smaller line at the very top of the --

MEMBER GOLD: That's the fiber optic cable?

MR. SPITZKOFF: Fib- -- but it also doubles as a static -- a static line for protection against things such as lightning strikes.

MEMBER GOLD: How does it protect against a lightning strike, it's a non-conductor?

MR. SPITZKOFF: That's one step beyond what I can explain to you.

MEMBER GOLD: Okay. So let's assume the lightning strike hits, oh, a worst possible place and burns out one of your switches, what do you do?

MR. SPITZKOFF: The line would come out of service, the switch would be replaced, and the line would be put back in service. And the way we operate our system and study our system to operate is to ensure what we call is a N minus 1 reliability. So we can lose any one element without losing generation or load as a result of that.

MEMBER GOLD: So you have backup switches. How long does it take to replace a switch?

MR. SPITZKOFF: I'd say, depending on the location, it could take hours to a day or two.

MEMBER GOLD: How many switches do you have in this plant?

MR. SPITZKOFF: In this -- I don't know off the top of my head. We generally have a switch on either side of all breakers. We usually have a line switch. The system overall has a lot of switches.

MEMBER GOLD: Okay. But the breakers are designed to stop a switch from getting burned out?

MR. SPITZKOFF: No.

MEMBER GOLD: No? Okay. What are the breakers designed for?

MR. SPITZKOFF: The breakers are designed to open up if the relays that are assigned to that breaker identify an abnormal system condition, which says there's something going on in the system, there's too much current, too much voltage, whatever the -- they're measuring. And the breakers open up to isolate wherever that fault might be to limit the event to either no equipment having long-lasting damage or just a small -- a footprint, a single element as possible.

MEMBER GOLD: So these are protected like circuit breakers in a house?

MR. SPITZKOFF: Yes.

MEMBER GOLD: They trip and you can manually turn them back on again?

MR. SPITZKOFF: Yes.

MEMBER GOLD: And they're designed to protect against lightning strikes and trees hitting poles and creating all sorts of weird stuff?

BY MS. BENALLY:

Q. Mr. Spitzkoff, I'm sorry to interrupt you, are you considering any confidentiality requirements relative to the responses that you're providing?

A. (MR. SPITZKOFF) These are general information at the moment.

Q. Okay. Thank you. Sorry for the interruption.

MEMBER GOLD: Ms. --

MS. BENALLY: Benally.

MEMBER GOLD: -- Benally. Then I'll ask you a question. Are you talking at the classified level or the unclassified?

MS. BENALLY: There are requirements that are set forth by the Federal Energy Regulatory Commission that describes information that is considered critical electric infrastructure information, so it was in that regard that I was asking Mr. Spitzkoff to evaluate his response.

MEMBER GOLD: So there is a system above the regular -- the standard circuit breaker system that we're discussing right now?

MS. BENALLY: I think --

MEMBER GOLD: You don't have to name it, just is there one?

MS. BENALLY: Yes.

MEMBER GOLD: Thank you.

CHMN STAFFORD: Member Fontes, you had your hand raised?

MEMBER FONTES: Yes, Mr. Chairman.

If we could bring it back towards applicability here. I think we're asking in terms of what happened at the WAPA Test Track facility, and I think that was a lightning strike to the transformer, not the circuit breaker.

So to educate and inform here, can you share how the design's going to take into account -- modeling takes that into account as a lesson learned against lightning strike protections on transformers. And then, number two, can you educate me on your modeling, is it the same for thermal energy storage and renewables with respect to these -- the analysis you're doing there that you just showed on that slide?

MR. SPITZKOFF: So on your second question, studies are basically independent of the fuel source type for the generator, from a thermal and voltage perspective. Where the differences will usually come in is in the transient domain or some of the other reliability studies that we do, because there's a difference between the behavior of inverter-based generation, as compared to spinning mass generation, thermal generation.

But we take into account -- our studies take into account all relevant -- we model each project specifically, so if it's an inverter-based generation, solar, batteries, wind, we model it accordingly. And then same thing for a thermal plant.

The first part of your question was about protection of transformers from lightning strikes, I believe?

MEMBER FONTES: Correct. Based on the test track, the WAPA one that burned down due to a lightning strike at the transformer.

MR. SPITZKOFF: I'm familiar with the transformer and the failure they had. I am not familiar with what the cause of that was. I haven't personally seen a report that says it was due to a lightning strike or not. And I -- I would say just the only thing I can provide is, in general, our substations and switchyards are designed with lightning protection in mind.

Now, when it comes to something like lightning, you cannot protect anything 100 percent. So is it -- is it possible lightning can strike a specific piece of equipment? That's certainly possible. There are some pieces of equipment that have their own individual protection, but overall the switchyards have lightning protection to try to minimize any adverse effects as much as possible.

BY MS. BENALLY:

Q. Mr. Spitzkoff --

A. (MR. SPITZKOFF) Yes.

Q. -- did you want to wrap up this part of your testimony by just stating what the results of the Reliability Study found?

A. (MR. SPITZKOFF) Yes, the Reliability Study found no adverse impacts in the results and no network upgrades required.

Q. Okay. Thank you.

So now I think we're moving to the next topic in your testimony, which is related to the generator interconnection request. And there are two, I believe, that you'll be addressing. Let's start with the APS generation interconnection request, if you'd walk us through that.

A. (MR. SPITZKOFF) Yes, I can.

Q. Thank you.

A. (MR. SPITZKOFF) So the APS generation team filed an interconnection request for the Redhawk Expansion Project. And they filed that request both to APS and to SRP. And I'll talk about the SRP request after the APS one. But the request was filed to APS because the connection of this project is going to be at the Redhawk Switchyard. And that switchyard is owned and operated by APS. So that's the point of interconnection. Hence, that's why an interconnection request is required to APS.

And just for a point of reference, and I think a question came up earlier, even APS in the capacity of building a generation ourselves or contracting for what would ultimately be an APS-owned generation, has to file an interconnection request. The same as any other entity requesting interconnection of new generation. So it's a -- the generation interconnection process is a nondiscriminatory process and requires APS projects to go through the same process.

So this project, in particular, there --

this -- it actually is covered under two interconnection requests. And I'll go into why two requests in a second. But the first request is covered under Q519 in the APS generation queue, and it's for 350 megawatts.

And that request is currently being studied. The phase I results of that study have been completed and delivered to the customer. And I'll -- in my next slides, I'll talk a little bit more about what the phase I results covered and showed.

But the second request that I had mentioned is covered by Q550, and you can see it's 43 megawatts. The reason for the two different requests, when the first request was made, the APS generation team was looking at 350 megawatts as what the output for this project would be. So they put the request in at that level.

Excuse me. At -- as the project developed and the specific generators that were going to be used were determined, and the different aspects of the project, it showed that the largest output could be approximately 393 megawatts. So, therefore, in the FERC interconnection process, an accepted and valid interconnection request cannot be increased in size, so the 350 was capped at 350 for that request. So the incremental amount has to be covered on a -- under a separate request. And that's why you see the Q550 request for the 43 megawatts, which covers that incremental amount. So that's why two different requests into the APS interconnection queue.

Q. So Q519 and Q550 added together are the 393 megawatts for the power plant; is that correct?

A. (MR. SPITZKOFF) Yeah.

Q. And they're being studied in two different clusters?

A. (MR. SPITZKOFF) Yes.

CHMN STAFFORD: Member Fontes, you have a question?

MEMBER FONTES: Yes, Mr. Chairman.

When was Q519 filed originally, month and year?

MR. SPITZKOFF: I wrote that down. Give me one second.

MEMBER FONTES: And, for clarity, Q550.

MR. SPITZKOFF: So I have -- I have it for 519. And that application was made March 30th, 2023. I -- I don't have Q550, but that is in the 2024 cluster, so that had to come in between April 1st of 2024 and March 5th -- and May 15th of 2024. There's a 45-day window.

MEMBER FONTES: Yes, sir.

Can counsel or somebody remind me of when the award was made on this, for the final selection for the Redhawk Expansion?

MR. DERSTINE: Mr. Eugenis, it sounds like that's a question that's probably going to come to you.

MR. EUGENIS: Member Fontes, we're still in the midst of our contract negotiations as part of this. The project was bid as part of the 2023 All-Source RFP, and those bids were submitted, I believe, Q3 of last year.

MEMBER FONTES: So Q3 of '23 and when did you get to the short list?

MR. EUGENIS: Member Fontes, I'd have to look up that date. Give me just a couple minutes.

MR. VAN ALLEN: Member Fontes, I'd like to add to the record, we know that the interconnection process takes time, and historically it was first-come, first-serve basis. In anticipation of the Redhawk project possibly being a project that got selected, the decision was made to submit a request, and we did that without knowing whether a project would be viable, right.

So you can withdraw a request at any time. And we know certain off-ramps that exist before certain dollars are obligated. So we proactively do that to ensure we can deliver our project on time and deliver certainty for our customers.

MEMBER FONTES: I really appreciate that, Mr. Van Allen. I'm just trying to get a sense of when the first interconnection was with respect to lead times in your bid solution and when your colleagues put you on the short list and stuff, for the record. So that's where I'm going with this, not attempting to show any kind of deficiencies, just getting it into the record, so we have that sequence there since they're in different parts of the presentation.

Thank you.

BY MS. BENALLY:

Q. Mr. Spitzkoff, I think I got you a little off-track or ahead of your testimony, so I appreciate you walking through why APS filed two interconnection requests. I think we've wrapped up that piece, along with APS being required to file an interconnection request as a part of non-discriminatory practices that are set forth in the FERC requirements.

So with that established, can you now walk us through the status of the APS interconnection request?

A. (MR. SPITZKOFF) Yes, I can.

Q. Thank you.

A. (MR. SPITZKOFF) The APS interconnection request for -- that's covered under 519, Q519, I mentioned a second ago, the phase I cluster study report for that has been filed. And the phase I study covers the thermal and voltage analysis. That was delivered about a month ago to the customer. The results of that assessment showed that there were no adverse reliability impacts to the system, with the addition of the Redhawk Expansion Project. And no reliability network upgrades were identified.

The phase I -- sorry, the phase II cluster study for Q519 is currently underway. It started once the phase I report was done, and results were presented to the customer. The estimated completion of the phase II is Q4, later this year. And that part of the study will cover the transient stability, the power factor, and short-circuit analysis. And that will close out the reliability studies for the interconnection that -- in the APS queue. So it's broken into two phases, phase I and phase II.

Q. So the next slide, I believe, is related to the SRP interconnection. And I know that Staff filed a letter in docket encouraging the Committee to ask questions about the current status of the SRP interconnection. Would you walk us through that?

A. (MR. SPITZKOFF) Yes. And before I get into that, so Staff did -- did mention asking about the SRP interconnection. They did not ask about the APS, because we did provide the phase I report to Staff, and so they had the ability to review that already.

For the SRP interconnection, that -- that study was delivered to APS this past Friday. I did take some time over the weekend to review, and it's in draft form at the moment, but I did take time to review, you know, what the high-level results showed. And I'll try to provide a summary of what that showed. And, really, the results did not show anything that would not be expected.

It -- sorry, before I get into that, in the SRP queue, this project was one project of 12 in their cluster 24. So it was a total of 12 projects that this got studied with, and all of those projects added up to close to 3,000 megawatts. So it was part of a larger cluster. And what the results showed is, as a collective, that that cluster has to advance one already planned 230kV line upgrade that SRP was already planning to do. And it showed it needed to be advanced by one year.

So relative to the Redhawk Expansion Project, it was that one, call it network upgrade, really network upgrade advancement is really what it was, and then it also had its -- its relevant contribution to the Palo Verde/Hassayampa short-circuit improvements.

And to explain what that is, at Palo Verde and

Hassayampa, there's been projects going on at those two switchyards for a number of years broken into three different phases, to address the short-circuit contributions by all of the lines, and all of the generation that you saw that was connected there.

So all generator and transmission interconnections in the state of Arizona and actually even into Southern California are reviewed by SRP as an affected system, to determine its contribution to the short-circuit currents at the Hassayampa/Palo Verde hub. And any project that is over a threshold gets assigned a per amp cost.

So, you know, it's known that most projects connecting into the 500kV grid of a certain size and relative proximity to Palo Verde/Hassayampa are going to have a share of that phase III upgrade requirements. But that was generally the extent of what the SRP studies have shown.

Q. Anything further you want to cover on the SRP interconnection status?

A. (MR. SPITZKOFF) Not really. Like I said, it's still in draft form. It will likely be finalized in the next three to four weeks. SRP has to have a results meeting with each -- each of the 12 interconnection customers, make any revisions or corrections that might

be identified, and then finalize the study.
Q. Okay. Thank you.
So let me take you back to Staff's letter, it's marked as APS-33 --
CHMN STAFFORD: Before you get to that, I have a real quick question.
MS. BENALLY: Yes.
CHMN STAFFORD: So you said there's 3,000 megawatts wanting to connect to the Hassayampa Switchyard?
MR. SPITZKOFF: It's more than just the Hassayampa Switchyard. Their cluster encompassed a wide area, so it's projects at the Hassayampa Switchyard. I don't remember all of them, but it could have been Hassayampa Switchyard, the Kyrene Switchyard, Rudd Switchyard or in various 500kV lines that SRP operates, so it was more than just the Hassayampa Switchyard.
CHMN STAFFORD: Okay.
MR. SPITZKOFF: But they were all in one cluster study.
CHMN STAFFORD: Okay. Because sometimes I think clusters get broken down different ways. I seem to recall that APS tends to do it by geographic area and the switchyard that they're going to be tying into or substation they're going to be tying into, as opposed

to -- this one sounds like it's casting a much broader net and covering a much larger area in multiple switchyards and substations.

MR. SPITZKOFF: SRP did break it -- I can't tell you their methodology exactly -- but generally, the projects within this particular cluster were in -- they were electrically relevant to each other, so geo- -- we say, on APS's side, we break our clusters into sub-clusters based on geography. It's geography plus.

As an example, we -- a project at the Cholla Switchyard which is, you know, in Northeast Arizona, would be in the same cluster as a project closer to Saguaro, which is in the southeastern area, because there's a 500kV line that connects them, so there's some relevancy there. And SRP sort of uses that same general principle. So they probably covered an area from Palo Verde on the west edge of their bubble to, I don't know if they went -- they definitely went to Kyrene, I don't -- I can't recall if they went all the way out to Pinal Central or if that was a second group, but our methodologies are not drastically different.

CHMN STAFFORD: Okay. Yeah, just wanted to make sure it's clear that it wasn't over 3,000 megawatts trying to get into this Hassayampa Switchyard. So, okay, it's not.

MR. SPITZKOFF: Yes.
BY MS. BENALLY:
Q. So APS-33 is the letter that was filed by Staff in response to the typical letter that the Chairman sends. Can you quickly summarize Staff's letter?
A. (MR. SPITZKOFF) I'll try.
Q. Or I can state to you what they've indicated and you can confirm it is consistent with APS's results. So Staff indicated that the studies that were provided or performed by APS indicate that "The proposed expansion project could improve reliability, safety of the grid, and delivery of power in Arizona," and that's consistent with the APS studies; is that right?
A. (MR. SPITZKOFF) That's correct.
Q. All right. So I think we're now to the point where you want to summarize your testimony?
A. (MR. SPITZKOFF) Well, I think Staff's letter summarizes my testimony.
So all of the reliability studies completed to date have showed no significant adverse reliability impacts to connecting this project to the grid, and I really think that's the big take-away.
Q. Okay. Thank you.
That concludes Mr. Spitzkoff's testimony.
MR. EUGENIS: Ms. Benally, before we move

on to the next panel, there was a couple of questions that have come up that I've gotten information for. Is now a good time to cover those or would you like to do that another time?

MS. BENALLY: Mr. Eugenis, why don't you go ahead and answer them. Thank you.

MR. EUGENIS: Thank you, Mrs. Benally.

A couple questions that we had received that I'm going to go through quickly here. Earlier it was asked how many projects that we had signed from the 2023 All-Source RFP. As of today's date, that's nine projects that we've signed from that RFP solicitation. There was also a question about the qualifications of our independent monitor, Merrimack. A quick search on them shows that they've been in the industry and formed since 1991. They've done over 100 different RFPs in a number of different states in the United States, with several members of their team participating in those different RFPs. That actually comes -- or Merrimack comes from an approved list of independent monitors from the ACC as well.

I believe we also had a question about the overnight cost of the project, as calculated in a dollar per kW fashion. Some quick math on our side shows that that's approximately $1,116 per kW for the anticipated cost of the project. And then, finally, I believe we had a question on when the project was short listed as part of the 2023 All-Source RFP. That short listing took place in late December of 2023 for the '27 and '28 in-service projects.

Thank you for the time, Mrs. Benally.

CHMN STAFFORD: Member Fontes, you have a question?

MEMBER FONTES: That overnight construction cost, and this is a related question, does that include the gen-tie?

MR. EUGENIS: Member Fontes, yes, it does.

MEMBER FONTES: On the other nine projects, where were they at on the interconnect? Did they have to file a subsequent or did they have a single interconnect? And how long had they been, on an average intermediate basis, in the queue prior to their selection? Just out of curiosity, in terms of comparison.

MR. EUGENIS: Member Fontes, I don't have that information in front of me. I think that those interconnection timelines are probably pretty varied between those projects. Just depending on the developer involved and how long that they've been working on the development of that specific facility.

MEMBER FONTES: Thank you.

MS. BENALLY: With the close of Mr. Spitzkoff's testimony, I think we're ready to move on to the next panel, our slate of environmental witnesses.

MEMBER MERCER: Mr. Chairman?

CHMN STAFFORD: Yes, Member Mercer.

MEMBER MERCER: I just have a clarification. So on the Bella Project, we learned that the Bella Project, they're building this facility, but it's going to be run and operated by SRP; is that correct, if you remember?

MR. SPITZKOFF: Yeah, I didn't hear the whole testimony of that project, but I think I caught that portion. And it was the switchyard for there -- where they're interconnecting will be operated by SRP. It will be owned by the joint owners of the current line, including SRP, but SRP is the operator for that switchyard.

MEMBER MERCER: Okay. So what's the case in this project, blackhawk [sic]?

MR. SPITZKOFF: So this project is connecting to the Redhawk Switchyard, which is owned and operated by APS.

MEMBER MERCER: And then who -- I'm sorry -- so who owns the Palo Verde, and I know you -- the way I pronounce it is Hassayampa.

MR. SPITZKOFF: Hassayampa, yes.

MEMBER MERCER: So who owns those -- those other plants.

MR. SPITZKOFF: There are -- so actually who owns the Palo Verde Plant is a bit different mix than who owns the switchyard. And it's six, seven -- seven different owners.

MEMBER MERCER: Okay.

MR. SPITZKOFF: I'm not going to be able to name all of them for you. And Hassayampa is much weirder. I think it's technically the same owners, but then you also have different cost-responsible entities, which are the natural gas plants. That was the creation for the need of developing Hassayampa, but it's -- it's the same seven owners that are the actual owners of Hassayampa. And SRP operates the switch -- both of those switchyards.

MEMBER MERCER: Okay. Thank you.

CHMN STAFFORD: Both of what switchyards?

MR. SPITZKOFF: Hassayampa and Palo Verde switchyards.

CHMN STAFFORD: Okay. Okay.

MR. SPITZKOFF: APS operates the plant, but SRP operates the Palo Verde Switchyard.

CHMN STAFFORD: Okay. And then APS owns

and operates the Redhawk Switchyard?

MR. SPITZKOFF: Yes.

MEMBER MERCER: Thank you.

CHMN STAFFORD: All right. Well, you're ready to move to the next panel?

MS. BENALLY: That is correct.

CHMN STAFFORD: And that will be Carlton, Nicholls, Turner, and Duncan, or is it some combination of those?

MS. BENALLY: It's the first three that you listed.

CHMN STAFFORD: Okay. All right. Well, it seems like now would be a good time to take a break, so you can switch the panels out. I'm sure the court reporter is ready for a rest. It seems like there were a lot of words in the last -- it hasn't been 90 minutes, but it's been a lot of typing.

So with that, let's take a 15-minute recess.

(Recessed from 2:17 p.m. until 2:42 p.m.)

CHMN STAFFORD: All right. Let's go back on the record.

Mr. Derstine, I believe you're about to call your next panel. You can call them and then I will swear them in. I believe Mr. Turner has already been sworn.

MR. DERSTINE: That's right. Okay.

All right. So we still have Mr. Van Allen there on the end. I think we largely have concluded his testimony, but he's there just for backup in case we get into some sort of operational issues that maybe he can address. But we need to swear in Ms. Carlton and Mr. Nicholls.

So, Ms. Carlton, will you state your name and address for the record.

MS. CARLTON: Anne Carlton, 400 North Fifth Street, Phoenix, Arizona 85004.

CHMN STAFFORD: And do you prefer an oath or affirmation?

MS. CARLTON: Affirmation.

(Anne Carlton was duly affirmed by the Chairman.)

CHMN STAFFORD: Mr. Nicholls, oath or affirmation?

MR. NICHOLLS: Affirmation.

(Mark Nicholls was duly affirmed by the Chairman.)

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ANNE CARLTON and MARK NICHOLLS,

called as witnesses as a panel on behalf of Applicant, having been previously affirmed by the Chairman to speak the truth and nothing but the truth, were examined and testified as follows:

D I R E C T E X A M I N A T I O N

BY MR. DERSTINE:

Q. And, just for the record, do you want to state your full name and your business address, Mr. Nicholls?

A. (MR. NICHOLLS) Certainly. My name is Mark Nicholls. My business address is 400 East Van Buren Street, Suite 545, Phoenix, Arizona. And I work for a company named Haley & Aldrich.

Q. All right. Ms. Carlton, let's talk air permits. Before we do that, let's have you tell us about yourself, your education and your background.

A. (MS. CARLTON) Sure. I have a bachelor's of science in human biology and environment that I received through Arizona State University. I have 18 years of experience in environmental with an emphasis on air quality. 12 years has been in the utility industry with APS, Arizona Public Service. I began my career with Arizona Public Service as an air consultant working for our environmental support organization, primarily responsible for air permitting. I moved into a section leader role over environmental field operations, which is everything outside of the power plant, so T&D, primarily.

And then most currently, for the last five years, I have been the manager of environmental support, where I oversee the air, waste, water, remediation, and a sprinkle of natural resources teams, who are responsible for things like regulatory changes, high-level permitting, as well as high-level reporting obligations.

Q. Okay. You're going to cover primarily the air permitting process required for the expansion project, but I think you're going to start us with a discussion about the existing air permit for the Redhawk Plant; is that right?

A. (MS. CARLTON) That is correct.

So my testimony today will include -- oh, sorry, I'm learning how to use the remotes. Here we go. I'm going to be going over the current Redhawk Power Plant permit, the air quality permitting process, our revision to our permit, and then the permit issuance. And if you'll notice, on the right-hand side of the slide because I know this isn't a typical subject for this type of hearing, I've included a little bit of a road map for you. And so as we progress through the slides, you'll always see one of these dots, and so you'll have an idea of where we're at in the presentation.

Q. Did you do that specifically for me because I kept getting lost?

A. (MS. CARLTON) That is correct.

Q. Fair enough. All right. Start us off with the Title V permit for the existing plant?

A. (MS. CARLTON) Perfect. So the Redhawk Power Plant currently operates under what's called a Title V permit. That's a type of permit that's required by the Clean Air Act, which is proctored by the EPA. It's technically an operating permit, and we'll talk about that in a little more detail in just a little bit. The permit was initially issued in the year 2000, in February, and it was issued by Maricopa County Air Quality Department. They are the delegated permitting authority for this type of permit within the region, essentially.

I think what's most important about this type of permit is that it requires you to comply with both operational, as well as emission-related requirements. These requirements found within your air permit are enforceable, at both the local as well as the federal level, in most cases. We are required to have inspections at our facilities by Maricopa County. EPA could show up to our facilities as well. We are required to monitor, so when we have things like emission limits in our permit, we're also required to monitor those emissions.

And, actually, utilities, specifically electric generating units, have what's called continuous emission monitoring systems, and they're not completely common throughout industries, but they're extremely common in our industry. And, essentially, it's probes that are literally plugged into these units that measure emissions on a minute-by-minute basis. And the minute-by-minute data is utilized to show that we are in compliance with things like our permit conditions, whether they're short-term limits or long-term limits.

Other robust requirements within these permits are things like performance testing. We'll actually have third-party vendors come in, and they'll verify that our continuous emission monitoring systems are functioning in the way that we said they should be. And so these permits are -- are quite restrictive, both from an operational standpoint, but also from an emissions standpoint.

CHMN STAFFORD: Member Hill?

MEMBER HILL: Thank you, Ms. Carlton. Have you ever violated your air quality permit on this site or across the state, like, what's the track record on these things?

MS. CARLTON: So I had actually done a research of what we've had at this facility, and I was not able to find any air quality-related violations within the last 10 years or so, but we also have what's called reportable environmental incidents, and that's a utility definition.

And because our Title V permits not only require us to provide things like monitoring and reporting, we also have to self-report when we haven't complied with one permit condition or another. But we didn't have any for this site for air quality in the last, I think it was seven to 10 years I went back.

MEMBER HILL: And, I know that you guys take this seriously, you wouldn't have set climate goals if you hadn't, but are there other vio- -- are other air quality violations, are there circumstances around that with other sites, in general, like, I'm just thinking about track record and --

MS. CARLTON: Track record? So we actually have a very low, I believe we're in the top quartile for compliance within the nation. And so I would say, from a track record perspective, we have a very good track record. What we do see in permits is more stringent or more difficult requirements, and we'll actually talk about some of those here, where maybe five or 10 years ago we would see something like a three-hour rolling average, now we'll see a one-hour rolling average.

And so for things like startup emissions, where they're really based off of the clock, if you start a unit at 9:50 a.m., so you only have 10 minutes remaining of an hour, it can be very difficult to comply with your one-hour limits if anything doesn't go perfectly correct with that unit. And so I believe the last violation we received was based off of one of those very short-term limits, but it was at a different facility.

MEMBER HILL: So even the changes in technology will create challenges as we adapt to new technology and emission standards?

MS. CARLTON: It's more like a tightening of the standards themselves. The technology is getting incrementally better, but then our requirements in order to comply are becoming more and more stringent as things change nationally.

MEMBER HILL: Okay. Thank you.

MS. CARLTON: You're welcome.

MEMBER KRYDER: Mr. Chairman?

CHMN STAFFORD: One moment, Member Fontes has his hand up.

MEMBER KRYDER: Sorry.

CHMN STAFFORD: And then -- then Member Kryder.

MEMBER FONTES: Thank you, Mr. Chairman.

Just a follow-up to that. I just want to double-check to see if Redhawk has ever exceeded the air quality permits for CO, CO2 or any kind of air emissions. The reason I want to do that is because you've got an existing power plant, we're building a peaker power plant, and when we get to talk about the physical attributes of the plant. And I want to talk and revisit the controls and the monitoring and how they're going to be segregated between the two plants. So if we can come back to that in that in that context, I would appreciate that.

MS. CARLTON: I'm sorry, I may have missed, was there a question that you needed me to answer at this point?

MEMBER FONTES: Can you confirm whether Redhawk has exceeded any air quality permit limits? And then, second, I would like, in the future, when we get to the design of the plant, to talk about the controls for air, water, and other discharge, and how they're going to be separate from the peaker plant and then the existing natural gas.

MS. CARLTON: Okay. So I have -- thank you for the question, Committee Member. I have data pulled up that goes back to 2009, and we do not have any excedances of our air permit recorded. And then in regards to emission control systems, we will definitely be talking about those specifically.

MEMBER FONTES: Is that with the Arizona Department of -- or the County?

MS. CARLTON: Maricopa County Air Quality.

MR. FONTES: Air Quality?

MS. CARLTON: Yes.

MR. FONTES: Okay. Thank you.

CHMN STAFFORD: Member Kryder.

MEMBER KRYDER: This may be difficult for you to answer because you just testified that you've not had any violations back for 2009, I think you said. So let me state my question, and maybe you can come at it from your other experience or something.

And that is, if the plant was in violation of the level of some pollutant, any one of them, does the plant shut down or do you simply say, oops, we're in violation, and we're doing the best we can to change some input factor to get back going? So the question evolves to do you continue to run if you're in violation or does the plant close down or what happens?

MS. CARLTON: Thank you for the question. So I want to make sure that it's clear that I'm not speaking for every instance, because let's say we're having an emergency alert and resources are very constrained. The answer could be different, depending on what is going on across the fleet, but I will talk to you in general about what occurs.

So ideally we avoid getting a permit exceedance. Alarms will start to let the control operator know that emissions are progressing in the incorrect direction. So emissions are looking high, maybe one of the emission control systems isn't functioning the way it should, and so an alarm will come through and ideally a control room operator will see that and be able to manage that issue prior to an exceedance occurring.

If, by chance, let's say one of those clock hour violations occurs, where you start up a unit at 9:55 a.m. and we have five minutes within that hour to identify is everything going well. Again, we're going to get alarms so that's great, those are all programmed into our system. But if there comes a point when the unit is not on track, the control operators in almost every case will be able to manage that, and it could result in the shutdown of the unit. As long as that's not going to compromise the grid, and it's not going to compromise the health of what is going on and we're not going to turn off the lights. So I would say that, yes, it could result in a control room operator turning off a unit.

MEMBER KRYDER: Okay. That's what I was hoping to hear that you would put into the testimony, what the steps were. And thank you very much. It's been a very clarifying answer.

MS. CARLTON: You are welcome. Thank you.

CHMN STAFFORD: Quick follow-up question. In the scenario you described where you have to run it even in violation of the air permit for reliability to keep the lights on, what is the remedy, is it a fine, do you have to do something else? What's the remedy for that?

MS. CARLTON: So, Mr. Chairman, in my 12 years of being here, we haven't had to face that, which is great. I'm very lucky for that. We do have a procedure in place that says if there is a declared emergency event, that we have essentially shared with the agencies that we have this procedure, and that we will notify them that we are in this state of emergency. Units will be kept on, essentially, even if we may be in violation of one of our air permits or maybe a water permit, and then we would be notifying the agency throughout the emergency of what mitigating strategies we'd be using to essentially turn off that unit as soon as possible. And the agencies were notified by the utility, by APS, but we have not actually had to put that into practice.

CHMN STAFFORD: Thank you.

Oh, Member Drago?

MEMBER DRAGO: Hi, Ms. Carlton.

MS. CARLTON: Hi.

MEMBER DRAGO: Would it be appropriate to talk about the reporting that's required if you do go unabated for any reason and you have to submit an excess emissions report? And then that excess emissions report, then, is compared to the total tons you're allowed, and then see if there's been a violation from that respect?

MS. CARLTON: Sure. So within each of our Title V permits, so regardless of the facility, but including Redhawk, and it will include the expansion permit as well, we are required to self-report. In some cases, the self-reporting is done on a semiannual basis, which is called a compliance report. In other cases, like excess emission, we actually have to report very, very quickly, within 24 hours. And we provide to the agency, essentially, what happened, maybe there was a malfunction, so you provide that detail. And then you would also provide to them how it was corrected.

In the case of a short-term permit violation, like a one-hour limit, it is considered a violation of your permit if you have a permit condition, which we do in Maricopa County, where they are one-hour limits. So that would be considered a violation, even if our tons per year is still met.

So we kind of have this layering effect of regulations within our permit, so while we're starting up, while we're operating normally, maybe some of our limits are one-hour limits or three-hour limits, or 24-hour limits, but to Committee Member Drago's point, we also have the tons-per-year limit that would cap our total emissions in any 12-month period. It's called a 12-month rolling.

MEMBER DRAGO: Thank you.

MS. CARLTON: You're welcome.

MEMBER GOLD: Mr. Chairman?

CHMN STAFFORD: Yes, Member Gold.

MEMBER GOLD: Ms. Carlton, aren't you running your plants at approximately 20 percent capacity?

MS. CARLTON: So in the case of this expansion project, we have proposed a limit of 20 percent capacity, but other facilities have no capacity factor, in some cases, and then some of them might have various capacity factors.

MEMBER GOLD: But your plant -- your proposed plant, that one we're looking at today, you're running at 20 percent capacity, usually that means if you have any kind of malfunctions or anything else, you switch to another generator?

MS. CARLTON: So I want to clarify that when we talk about capacity factor as, you know, 20 percent for the expansion, it's not generally running, that's our maximum ability to run in a period of time in a 12-month rolling. So we may run much less than that, actually.

MEMBER GOLD: So you will have more than enough opportunities and capacity so if anything goes wrong just switch to something else, turn it off.

MS. CARLTON: To be honest, that's correct. Yes, unless there's constrained operations.

MEMBER GOLD: Plenty of safety built in. Thank you.

MS. CARLTON: You're welcome.

CHMN STAFFORD: What about the existing plant, what's the capacity factor for that? What does it operate at, approximately?

MS. CARLTON: I have the tons per year in my notes, but I don't have how it translates to capacity factor, but I can tell you, because we recently evaluated, the plant runs around 50 percent capacity factor, 50 to 55.

CHMN STAFFORD: Okay. I imagine it runs pretty much all the time in the summer?

MS. CARLTON: I'm sure it's given stress to multiple people on this panel besides me, but yes. The combined cycles are typically higher-use units due to their configuration.

CHMN STAFFORD: All right. Thank you.

MS. CARLTON: You're welcome.

BY MR. DERSTINE:

Q. So you've outlined the existing Title V permit for the combined cycle plant. You want to take us through -- you're going to need to revise that permit for the expansion project. What's the process for doing that?

A. (MS. CARLTON) Sure. And as you can see we are in the air permitting process. And so this is just a high-level overview of where we're at in our presentation.

So I talked to you a little bit about Title V, and how that's a permit found under the Clean Air Act. Title V is actually an operating permit. In most states, facilities have to get a construction or a preconstruction permit and then an operating permit, whereas in Arizona we have a unified permitting program, and so it means those things are actually combined.

And the reason that this is different is because we are required to open up our existing operating permit in order to build the expansion project. So we will have permit conditions related to the building, as well as the operation of the new units. It's also important to note, from a timeline perspective, which we'll talk about in just a second, we need to have this permit finalized in order to begin actual construction of the eight new units, and so we have to start this process relatively early on.

Before I jump over to timeline, I do want to talk about the air quality status of where Redhawk is located. And the reason why it matters. So Redhawk is located in a non-attainment area for ozone pollutants, which would include nitrogen oxides, as well as volatile organic compounds, but it's in an attainment area for other pollutants, like particulate emissions, and that's because it is located outside of the Maricopa County non-attainment area.

MEMBER GOLD: Mr. Chairman?

CHMN STAFFORD: Member Gold.

MEMBER GOLD: Would you please define

"attainment" and "non-attainment" just for a layman?

MS. CARLTON: Oh, absolutely. I was going to get there. Thank you, Member Gold.

So non-attainment and attainment are related to another term that I'll help everyone understand, which is National Ambient Air Quality Standards. So when you're in attainment, it means you're meeting those standards. And when you're in non-attainment, it means you're not meeting those standards.

So what are the standards? Standards are set by EPA and actually an advisory committee that's comprised of scientists; they're reviewed on a five-year basis, they're often lowered. And essentially they're standards of how much pollution is, I'm going to say acceptable, even though what level of pollution is acceptable? But it's essentially what's -- what's protecting human health, including sensitive populations, like the elderly, young people, and asthmatics.

And so if a facility is in an attainment area, it means that the air quality is generally pretty good. If you're in a non-attainment area, it means the air quality is not meeting those standards. And what happens when you're in a non-attainment area, like Maricopa County, or recently we talked a little bit about

Pinal County as well, is that those locations are required to create programs in order to lower their emissions overall, trying to -- so they try to get back into attainment.

And so when you have a non-attainment area, like Maricopa County, there's going to be a large suite of rules that impact a variety of industries, utilities included. And so the rules are set and they dictate how we permit. And what types of permitting thresholds we have to achieve. And how low of emission rates we actually have to operate at.

And it's in an effort to not make the air quality worse in the area, but in some cases it's meant to actually improve the air quality in the area as well.

MEMBER GOLD: Why is Maricopa County a non-attainment area? What's wrong with the area?

MS. CARLTON: So if we were to pull up their emission inventory pie, which essentially shows people what sources are contributing to pollution, you would see in that presentation that vehicles are a contributor to ozone, utilities, industries, maybe possibly like chip manufacturing, it's anyone who is either burning fossil fuels, which could be a car, could be a facility, or is using volatile organic compounds, like solvents, that's also another contributor.

Another main component of air quality status in Maricopa County is sunlight. Ozone is created through sunlight. It takes chemicals that are in the air, and it breaks them up, and it aids in the creation of ozone. So, typically, sunnier locations can have more trouble complying with ozone standards.

MEMBER GOLD: So what you're saying is because the sun shines, we have very poor air quality regarding ozone?

MS. CARLTON: It's certainly not the only reason, but it can contribute to it.

MEMBER GOLD: Okay. What else -- I mean, are there man-made stuff that's causing this or is this caused by the environment that we're just living in?

MS. CARLTON: Vehicles are a major contributor to ozone pollution, and industrial sources are incrementally adding to that as well.

MEMBER GOLD: Okay. I just looked at the area where you're putting the plant in, and there's nothing there.

MS. CARLTON: The non-attainment areas are dictated by sources. So when a location moves from attainment to non-attainment, an agency will review the potential sources, whether it's vehicles or facilities that could contribute to it, and they will designate the non-attainment area based off of that. And so if you noticed, there wasn't a whole lot out there, but there are quite a few generating facilities out there, and so it makes a lot of sense, from an agency perspective, that they would want the non-attainment area to include sources like Redhawk, like Mesquite, like Harquahala, because airshed is not stationary. The emissions from Redhawk don't just live on top of Redhawk, they may move around Maricopa County and contribute overall to an attainment status.

MEMBER GOLD: So I come from New York and I've lived in Los Angeles. And then I'm gathering those areas are horrible non-attainment areas, because of all the vehicles and stuff that's going on there. But now I live out in the middle of the desert, and is this because we have temperature inversions and a lot of sun and stuff like that, the natural causes of these pollutants are far more than the man-made causes of these pollutions? Was this area non-attainment before we had power plants?

MS. CARLTON: Member Gold, I would definitely say that I'm not an expert in all things non-attainment when it comes to how the ecology will interact with it. I have an air quality background, I understand how these things work, but I wouldn't want to weigh in on, you know, is it where we live or is it the facilities and cars. I would say that it's definitely a collection of all of those things.

MEMBER GOLD: Okay. My ques- -- what I really wanted to know is are natural causes more or greater than our plants? What is -- what's primarily causing this to be a non-attainment area? And I've noticed that there are days when the weather report says "and there is a health emergency" or "an air quality alert." And it's not because people are driving their cars more, it's because of something else. What I'm asking is, is that something else, something out of nature, or is that something else something caused by our plants that we're building?

MS. CARLTON: Member Gold, I can definitely get you a copy of the most recent emission inventory, if you'd like to see the distribution of emissions that Maricopa County provides publicly as to how they're distributed. But, to your point, things like inversion factors will make a difference on where pollution sits, and whether it's able to disperse. So you are correct with that statement.

MEMBER GOLD: In that case, thank you, if you can get that, I'd appreciate it. I would also love to see one, if you could get one, from 100 years ago. I'd like to see what that looks like.

MS. CARLTON: I may be less effective with that, but I'll try.

BY MR. DERSTINE:

Q. Ms. Carlton, so we had this discussion about Maricopa County being non-attainment, it's not in non-attainment for every criteria pollutant, right? If I'm looking at your slide 179, it indicates that Maricopa County is non-attainment status for ozone pollutants, attainment all other criteria pollutants.

Do I have that right?

A. (MS. CARLTON) That is correct.

Q. Okay. So the differentiation is there are listed criteria pollutants of which are part of the National Ambient Air Quality Standards, and as to ozone, Maricopa County is non-attainment as to that pollutant; as to all the other listed or scheduled criteria pollutants, Maricopa County is in attainment for those?

A. (MS. CARLTON) Yes.

Q. Okay.

MEMBER GOLD: Mr. Chairman?

CHMN STAFFORD: Yes, Member Gold.

MEMBER GOLD: Mr. Derstine, thank you very much for that.

What produces ozone? Does your plant produce ozone?

MS. CARLTON: Our facility will emit nitrogen oxides, as well as volatile organic compounds, and both of those contribute to the creation of ozone.

MEMBER GOLD: Ozone is O3, to the best of my knowledge, there's no nitrogen in it?

MS. CARLTON: Correct.

MEMBER GOLD: So it says non-attainment ozone pollutants and nitrogen oxides?

MS. CARLTON: Correct. So those two pollutants can interact in the atmosphere and aid in the creation of ozone.

MEMBER GOLD: Oh, oh, oh. So nitrogen oxides and volatile organic compounds can produce ozone. Does your plant -- does the proposed plant produce nitrogen oxides and other volatile organic compounds?

MS. CARLTON: Yes.

MEMBER GOLD: Why?

MS. CARLTON: So currently emission control technologies will, like, will severely reduce the amount that we emit of those pollutants, but they do not get them down to zero.

MEMBER GOLD: Okay.

CHMN STAFFORD: But nitrogen oxides and VOCs, those are produced by burning fossil fuels, correct?

MS. CARLTON: That is correct.

CHMN STAFFORD: And then what happens to the non-attainment area if -- isn't there -- doesn't the EPA set a standard or some kind of schedule to begin reductions or -- at some point if they keep increasing to some level, it's higher than it is now, what will be the consequences for Maricopa County?

MS. CARLTON: So if an area is unable to meet the attainment standard, they are going to move further into non-attainment. And we actually will talk about that a little bit throughout this presentation, but what happens is the rules become more stringent and more restrictive, and permitting becomes more challenging. And so what ultimately happens is the regulations just get harder to comply with, and that permitting may become less and less possible.

CHMN STAFFORD: Right. So at some point they'll stop issuing air permits for anything that emits nitrogen oxides and VOCs, theoretically.

MS. CARLTON: Theo- -- well, without the use of offsets. So as you move further into attainment, offsets are required, which we'll actually talk about during the permit revision section of this presentation.

CHMN STAFFORD: And I'm assuming that offsets raise the -- significantly raise the cost of compliance.

MS. CARLTON: They absolutely can.

CHMN STAFFORD: Member Hill?

MEMBER HILL: Ms. Carlton, there are different levels of non-attainment; is that correct?

MS. CARLTON: Yes.

MEMBER HILL: And as you -- as the air quality conditions worsen, for lack of a better -- over time, the health risks become more significant for the public, and that's why they start to impose more regulation to try and reduce emissions.

Can you talk about it -- because I feel like the tone of this conversation, I want to be careful about this, is we are over-regulated, but at the end of the day we're talking about public health. And so I just want to make sure that when we talk about this, it doesn't feel like we're over-regulated and it's a burden.

I mean, we are talking about public health, at the end of the day, and there -- I call it -- we're in non-attainment non-attainment, because it's level 2 now, because we continue to -- the pollution per capita isn't going up, but at the end of the day it's been a problem.

So can you just talk a little bit about the levels, and -- I guess we've talked about the -- I don't know, I'm struggling with this tone. And that's what I was just trying to reset on. And so if you have comments about that, that would be helpful.

MS. CARLTON: Yeah, I appreciate that, Member Hill.

So when an area does not meet its attainment status, it will move into non-attainment, as you mentioned. When it moves further into non-attainment, it does not necessarily mean pollution is getting worse. It means that it's still not achieving attainment. And so the plan that was crafted by the agencies need -- they need to do more. They need to reevaluate and reassess. And so I do want to clarify that it doesn't necessarily mean that air quality is getting worse.

In some cases, when we look at non-attainment areas, it can be extremely challenging to manage attainment within the region, because of possibly interstate transport, international transport, and then natural conditions, as Member Gold described. And so when they fail to meet the attainment standard after a period of time, they will reevaluate all of those conditions, and they will -- the State will be required, with Maricopa County in this case, would be required to then redo their state implementation plan.

If the State fails to achieve or to

complete their state implementation plan in such a way that EPA will approve, then the federal government has the right to implement a federal implementation plan. My understanding, and there's a whole lot of state implementation plans, but let's just keep it focused on ozone, is at this point we are -- I say "we," the State has a functional state implementation plan. It is very clear that they are not going to meet the attainment standard, and so they are going to have to redo that plan, which is likely to occur in 2025.

MEMBER HILL: Thank you for that background.

MS. CARLTON: You're welcome.

CHMN STAFFORD: Real quick question. Will that affect your permit application?

MS. CARLTON: We have accounted for that and we will discuss it during this presentation, yeah.

MEMBER GOLD: Mr. Chairman?

CHMN STAFFORD: Member Gold.

MEMBER GOLD: Are coal-fired plants more polluting with these ozone pollutants than gas-fired plants?

MS. CARLTON: Member Gold, it is fair to say, in general, that coal plants have higher emission rates for all pollutants compared to the natural gas plants.

MEMBER GOLD: So these plants you're developing are used to replace the coal-fired plants; is that not correct?

MS. CARLTON: We are retiring a number of coal plants, and this resource was determined to be required based off of some of those retirements.

MEMBER GOLD: So in simple layman's terms, by getting rid of the coal plants and putting in gas-fired plants we're cleaning the air? Yes?

CHMN STAFFORD: I don't know if you can say you're cleaning the air, but you're polluting it at a slower rate.

MEMBER HILL: In a non-attainment zone.

MEMBER GOLD: I can live with that. The air quality is getting better because we're replacing coal-fired plants with less polluting gas-fired plants. And if you were going to measure the air by coal-fired plant standards, it would be worse than by gas-fired plant standards. And we're looking at permitting a gas-fired plant, not a coal-fired plant. So I'm asking this is better than coal, isn't it?

MS. CARLTON: Member Gold, I would say that you are correct in that natural gas plants emit less across the pollutant field than coal plants. But I would also say that Member Hill is correct that our coal plants are retiring in a different region.

MEMBER GOLD: Yeah, but air travels, you know, it doesn't stay in one region, the wind blows, and it goes from west to east. And when you're talking about pollution, you know, people say we want zero pollution, well, son of a gun, then get rid of people, and you'll have zero pollution because we breathe and we have other processes.

I'm looking at this plant, this plant is better than other plants that burn coal, and we're replacing the coal-burning plant with the gas-fired plants, which sounds to me like an improvement. So I'm saying I understand you're non-attainment, but this is going to make your, quote-unquote, trying to use these words, the non-attainment level was here, now it's going to be here, because we're doing less of this bad stuff, and we're doing something that's not as bad.

All I'm saying is this plant is a good alternative to the coal-fired plants, and to say that the coal-fired plants are someplace else, the wind is still going to blow and it circulates from west to east. Where are the coal-fired plants that we're retiring, east of us or west of us?

MS. CARLTON: Member Gold, one of the coal plants that's retiring in 2025 is located in Joe City, which is --

Am I correct to say approximately 40 miles east of Flagstaff? Is that correct? Or is it further?

MR. VAN ALLEN: It's about an hour drive, so --

MS. CARLTON: An hour drive.

MR. VAN ALLEN: -- about 80 miles west of Flagstaff.

MEMBER GOLD: Okay. So knowing weather patterns generally blows from west to east, but you have the counter-circulating currents, and the lows are counter-clockwise, highs are clockwise. The air's going to move. And generally the air that Americans are going to be breathing will be better with gas-fired plants than keeping the coal-fired plants? In short, you're doing a good job.

MR. DERSTINE: Thank you.

MEMBER GOLD: All I'm saying is I think the project sounds like a good project. That's just my comment from a very non-technical point of view.

CHMN STAFFORD: Member Fontes, is that you with your hand raised?

MEMBER FONTES: Yes, Mr. Chairman.

I'd just like to remind that we're focused on the air permit and discussion of the air, and that's looked at, I think, at the County level, and so if we can get back on track.

CHMN STAFFORD: Thank you.

BY MR. DERSTINE:

Q. Ms. Carlton, in part of your slide there, I think your next step you talked about the air quality status, non-attainment, attainment, you were going to do a high-level discussion of the permitting timeline for the revision for the Redhawk Expansion Project.

A. (MS. CARLTON) Sure.

This is from APS-11, page 180. We utilized the actual Redhawk permit submittal as an example, just to give you some general time frames. We submitted that application in April of 2024, with Maricopa County Air Quality. And I can tell you that application is around 170 pages long. It encompasses quite a few things, proposed emission limitations, operational limits, technology reviews, and assessments. And some other items that we'll go over in just a little bit under our permit revision, but it's a quite extensive permit.

But I think one of the key elements here is that there's a lot of variability in the permitting time frame. When I'm asked by my management, you know, how long is this going to take me? I will typically say anywhere from 18 to 24 months for this type of permit just because it is so extensive. And you'll see that the bulk of the time is spent drafting permit.

And you might be wondering, well, if you supplied them all of your conditions and all of these emission limits, why would it take so long? It's because the agency, one, has the authority to take anything that we've provided and to change it, and to make it more stringent, but they also have the ability and the requirement to also perform technology assessments, and look nationally to see what's going on due to that non-attainment status. They've got to make sure that this permit is fitting for the location.

And so this can take quite a while. We typically go back and forth with them over the course of anywhere from 12 to 14 months. And then what we get to is what's called the final draft permit. And that final draft permit will go out for what's important is a 30-day public comment period. And so the public does get to interact with this type of permitting action. They will be notified, both through the newspaper, as well as the Maricopa County website that our draft permit is available for them for review. And then APS will be requesting an open hearing that will be held at the end of that public comment where people could also come and provide verbal comments.

The agency is required to take any written and verbal comment and respond to it. If something substantial were to come out of those comments, we could actually end up where a new draft permit is issued, and we go out for public comment period again. And when I say "substantial," it could, you know, maybe the removal of a permit condition or the addition of a permit condition, something brand-new. It wouldn't be something like a clarification of a permit condition. But that cycle could get repeated more than one time.

Once things get through the public comment period, and the agency has time to respond to each comment, it will go to EPA review, so not only Maricopa County, who is the delegated authority reviews this permit, but also the federal government through the EPA. They have a 45-day review which, again, they could come back and say, you know, we don't love this or we want you to do more. We would like a one-hour limit instead of a three-hour limit, and in that case the permit could possibly be redrafted and then re-public comment and re-EPA reviewed again.

So this timeline, I think one thing I just want to make sure is clear is, we have a December/January 2025, right through 2026, time frame that we're thinking this will be finalized, based off our historic permitting. But it's -- it's likely that this could be a little shorter or a little longer.

Q. And the actual application for revision of the existing Title V permit for Redhawk is included in the CEC application, which is APS Exhibit 1, and I think the permit application or the revision application is B-1 to APS Exhibit 1; is that right? Sound right?

A. (MS. CARLTON) That sounds correct.

MEMBER FRENCH: Mr. Chairman?

CHMN STAFFORD: Yes, Member French.

MEMBER FRENCH: Ms. Carlton, at what point in this timeline is that capacity factor for the plant determined?

MS. CARLTON: So APS has provided a proposed capacity factor, which I'll dive a little bit further into in another slide, but that is something that we provide.

MEMBER FRENCH: And I assume that that capacity factor that you determine is then communicated to the regulating entities and then you have communications back and forth?

MS. CARLTON: Correct. So what is likely to occur if our permit is finalized as proposed is that we will have a limit wrapped into our permit that is based off of fuel burn, and we would be required do actually submit a report on some frequency showing that we are complying with that.

MEMBER FRENCH: Okay. Thank you.

MS. CARLTON: You're welcome.

CHMN STAFFORD: And that will be across all 10 units, right?

MS. CARLTON: Eight units.

CHMN STAFFORD: Doesn't the air permit cover all 10 units?

MS. CARLTON: The operating permit will cover all 10, but the capacity factor limitation is for the new units.

CHMN STAFFORD: Okay. So there will be a separate fuel cap for the existing plant, as opposed to the expansion project?

MS. CARLTON: That is correct.

CHMN STAFFORD: Okay.

MEMBER KRYDER: Mr. Chairman?

CHMN STAFFORD: Yes, Member Kryder.

MEMBER KRYDER: One question, Ms. Carlton. And maybe this is not your area. And if so, send it to the right person. Is all natural gas identical or the equivalent of premium and regular?

MS. CARLTON: So thank you for the

question, Member. We have permit conditions that dictate the type of natural gas utilized, and it's pipeline natural gas, which is defined in the permit.
MEMBER KRYDER: I'm sorry, I didn't understand. Say that again for me, please.
MS. CARLTON: Let me find you the definition.
So our definition of pipeline natural gas dictates that we will burn natural gas that meets certain sulfur dioxide requirements, so it's based off of emissions.
MEMBER KRYDER: But the -- so you're saying that the natural gas that comes out of El Paso or the other company that the line goes to your property there, would be identical or it's all regular or can I buy high test too?
MS. CARLTON: I would need to default to likely Mr. Eugenis for that question.
MEMBER KRYDER: Okay. I'm ready.
MR. DERSTINE: Or if Mr. Van Allen can answer it.
MS. CARLTON: Or Mr. Van Allen, yeah.
MR. VAN ALLEN: Member Kryder, the gas we get through the pipeline system meets the federal standard for pipeline quality gas. You're correct, there

are parts of the country that have different grades of natural gas. And as Ms. Carlton stated, higher sulfur content, but we have, in the western U.S., high-quality natural gas that has relatively low levels of sulfur that -- that is to our benefit.

MEMBER KRYDER: And so you can specify when you buy from El Paso or the other company certain, you called it a federal regu- -- regulated level or something?

MR. VAN ALLEN: When gas is transported across state lines, it has to meet certain standards. And that is all regulated. These gas companies also keep instruments on their system, and they take daily readings, gas chromography [sic], and it analyzes the chemistry of that gas, the constituents within it. So it meets a very high standard.

MEMBER KRYDER: Okay. Thank you. What I was looking at was it would seem to me the fuel that you burn would impact significantly the output of the stack. And you clarified for me that you have a standard fuel consistency figured out by the gas chromato- -- chroma- --

MR. VAN ALLEN: Chromograph.

MEMBER KRYDER: -- chromograph. And so you can make your equipment function according to that standard. And everybody's up and down the line regulated so that you know what you're getting into the generators so that you also can better predict what's coming out the stack.

Thank you very much. That's quite helpful.

CHMN STAFFORD: Quick question. So all the gas that would flow to the site, either from the San Juan or Permian Basin, it meets these standards?

MR. VAN ALLEN: Chairman Stafford, it does meet those standards. We do have contract guarantees in the fuel agreements that we have in place that they have to meet certain fuel standards as well.

CHMN STAFFORD: Is there a difference in solvent content between the San Juan and Permian basins?

MR. VAN ALLEN: I don't have that information. I'm happy to investigate and get that for you.

CHMN STAFFORD: Thanks.

BY MR. DERSTINE:

Q. Did you get as far as you wanted to go on the timeline?

A. (MS. CARLTON) I think I did. Thank you.

Q. Okay. Do you now want to delve into the actual -- the terms of the Title V permit application?

A. (MS. CARLTON) Absolutely.

So as you have heard throughout the last couple of days, we are planning to build eight combustion turbines. They are LM6000s, which we have operated at other facilities. These units will be equipped with emission control systems that are considered state of the art. Our selective catalytic reduction will be used to control nitrogen oxides, and oxidation catalysts will be utilized to control carbon monoxide, as well as volatile organic compounds.

It's very important to note that when we evaluated and went through the permitting process, these controls, specifically the SCR, the selective catalytic reduction, are required, and that is because since we are permitting in a non-attainment area, and based off of our maximum potential to emit, we are required to achieve the lowest achievable emission reduction, which means that we will have some of the lowest emission rates in the country, when it comes to things like nitrogen oxides.

So our emission rate for nitrogen oxides will be 2.3 PPM. And that would -- it's parts per million, which will be on an hourly basis during normal operations. And again, that is the lowest achievable emission rate.

MEMBER GOLD: Mr. Chairman?

CHMN STAFFORD: Yes, Member Gold.

MEMBER GOLD: That's what I asked before.

I just didn't phrase it right, but I'm looking at your next chart, you will provide a net air quality benefit. Is that the correct phraseology for saying it's going to be better?

MS. CARLTON: We will be talking about emission offsets, which, as you just gave a prequel to, does have net air quality benefit. We will dive into that a little bit deeper. Our permit also includes a variety of other conditions that I described that are our current Title V, but another one is the 20 percent capacity factor. It's actually less than 20 percent, it's around 19.4 percent.

That was chosen in order to meet compliance obligations with the very recently finalized greenhouse gas regulations. This capacity factor will put us through the low load category, which is just a fancy way of saying that they understand that these are peaking units, and that our compliance obligation under that rule would be to burn natural gas. And so it will keep us out of the requirements of the rule that would mandate something like carbon capture sequestration, which is currently in the rule for more baseloaded-type units.

Other items that are in this permit, which we can dive into if everyone's ready, unless Matt has another -- or Mr. Derstine has another question for me --

sorry.

CHMN STAFFORD: Well, I have another question, actually.

MS. CARLTON: Oh, sure.

CHMN STAFFORD: So water is used to reduce the carbon monoxide emissions, correct?

MS. CARLTON: It is used to actually reduce nitrogen oxide emissions. It's used to cool the inlet air temperature.

CHMN STAFFORD: What is used to reduce the carbon monoxide emissions?

MS. CARLTON: Catalytic reduc- -- or, sorry, an oxidation catalyst.

CHMN STAFFORD: The SCR does?

MS. CARLTON: The oxidation catalyst is a separate component than the selective catalytic reduction. They sound quite the same; they actually operate quite the same way, but they are different emission control systems.

CHMN STAFFORD: Okay. And then the -- and then the CO2 emissions are limited to what, like, 1,100 per megawatt hour or something?

MS. CARLTON: Let me look. I've got that. So our --

CHMN STAFFORD: That's the new regulation in subpart TTTT, or something.

MS. CARLTON: So, correct, we do have the subpart. These units would actually fall under the new greenhouse gas regulation, not the existing. But it is our carbon dioxide that we are proposing is 1,450 pounds per megawatt hour gross electric output.

CHMN STAFFORD: Okay.

MS. CARLTON: And that is based off of best available control technology.

CHMN STAFFORD: All right. And then you said the capacity faster -- the capacity factor, that's the hard cap, and that's going to be the fuel?

MS. CARLTON: So we will have many hard caps, but that will be one of them, and that is based off of the amount of fuel that we are able to burn.

CHMN STAFFORD: And that's -- you have a different number, I think you said this before, so I want to make sure I'm getting this, you have a different number for the existing plant than for the expansion?

MS. CARLTON: Correct. So the existing plant will continue to operate under its operating provisions. It will not be impacted by this permit modification, whereas these eight combustion turbines will have, like, their own set of criteria, and they'll be delineated in the permit pretty much normally by name, so it will be combined cycle 1 and 2 and then likely CT, I don't know if we're naming them 3 through 8 or 3 through 10, however we'll name them, but it will be clearly delineated in the permit.

CHMN STAFFORD: So is there a separate meter for each seven units?

MS. CARLTON: Yes, we do. So just like the continuous emission monitoring, we've got systems that are attached to each individual unit that measure things like fuel burn and emissions.

CHMN STAFFORD: Oh, for each individual, so 1 through 10, each one has a separate calculator of how much fuel each one's burning?

MS. CARLTON: Correct. Yes.

CHMN STAFFORD: Okay. All right. Thank you.

MS. CARLTON: You are welcome.

BY MR. DERSTINE:

Q. Member Gold was interested in your offsets, is that the next area you wanted to cover?

A. (MS. CARLTON) Sure.

And please let me know if I'm talking too fast.

THE REPORTER: You are.

MS. CARLTON: Okay. I will slow down. This is me talking slowly, so I will -- I will take it down a notch.

All right. So this is related to a net air quality benefit, but it's not completely aligned with Member Gold's discussion related to coal closures and the addition of gas plants. But I'll try to explain this and please feel free to interject with questions.

So in a non-attainment area where regulations get tighter and permitting thresholds get lower, there's an acknowledgement under the Clean Air Act that a non-attainment area may still desire and need economic development, and so when you start to kind of think about how you would handle that, from an air quality perspective, this is where emission offsets were derived.

So, essentially, if you are looking to build a new facility or expand upon a facility, and your maximum potential to emit is above a specific threshold, you are required to offset your emissions. And by offsetting your emissions, you are actually removing more emissions from the airshed or the location, in our case Maricopa County, than you are asking to add.

And so I think one thing that can help us look at this, is the presentation or the slide to your right, 184, from APS-11, again, we're in that permit revision section, so this can actually be found in our permit application. You'll notice I have two sets of calculations for you, and I believe, Chairman -- Mr. Chairman had alluded to the fact that we may have a change in our non-attainment status.

Currently we are in moderate, and it is very likely that we will move to serious before the finalization of this permit. So we actually accounted for that in our application, and we provided two sets of calculations for our emission offsets. So our facility has a maximum potential to emit for nitrogen oxides of 59 tons. If the County is in moderate non-attainment when everything is finalized, we will be required to have a 15 percent reduction. So we would have to provide 68 credits. And think about credits as in tons of pollution, because that's what it is.

In a serious non-attainment area, it's even more. So you'd have to have a 20 percent reduction, and so depending on where we're at in the non-attainment status change, we will either have to provide 68 credits or 71 credits. And in both cases we are able to do that. And we were able to do that by reducing our emissions in a fashion that was above our compliance obligation, so we controlled emissions more than we were required to do so at our West Phoenix Plant on combined cycles one and two.

CHMN STAFFORD: So that means they --

they'll put 59 tons less of the criteria pollutants out?

MS. CARLTON: So we are looking to our maximum potential to emit is 59 tons. But we have to essentially give back 68 tons, so that means we lowered our emissions at that West Phoenix Power Plant by actually more than 71 tons.

CHMN STAFFORD: Okay.

MS. CARLTON: And so if you look at what we took out of the airshed versus what we're requesting to add from a maximum potential, there's at least a 15 percent, if not a 20 percent, difference, depending on the permitting scheme.

CHMN STAFFORD: And you did that by running it less?

MS. CARLTON: It wasn't by running less, it was actually over-control of the unit. We installed a selective catalytic reduction in order to meet a requirement and that emission control system controlled it more than what we were required to do. So the unit is operating in a cleaner fashion than what the agency was requiring us to do.

CHMN STAFFORD: And so anything you -- any reductions you do beyond what was required counts as a credit that can offset higher emissions elsewhere?

MS. CARLTON: Correct. So maybe not higher emissions, but it's actually less emissions, because I've offset 71 in the case of serious non-attainment, but I'm only asking to emit 59.

CHMN STAFFORD: Okay. All right.

MEMBER DRAGO: Mr. Chairman?

CHMN STAFFORD: Yes, Member Drago.

MEMBER DRAGO: Maybe we should add that you would not be able to take a credit outside of the non-attainment area, correct?

MS. CARLTON: That is correct. So they do want you to evaluate it on a local basis. So I couldn't shut down one of my coal plants in Navajo County and get credit for it in Maricopa County. Because it's an attainment area, it's not the same airshed.

The other, I think, important thing to note is that credits have to be permanent, so this isn't something I can just undo at West Phoenix and then emit more there and emit more at Redhawk. There's a lot of provisions related to obtaining a credit that are required to be met in order to be able to what's called bank them.

MEMBER GOLD: Mr. Chairman?

CHMN STAFFORD: Yes, Member Gold.

MEMBER GOLD: Ms. Carlton, what's an airshed?

MS. CARLTON: Just like an area where air pollution moves around and gets shared. And so when you think about Maricopa County in its entirety, you know, you talk about it like a -- a local area.

MEMBER GOLD: So Maricopa County is like a bowl and the other airshed is like another bowl?

MS. CARLTON: Per monitoring, it would be part of the area that, you know, shares the same problems. So when we look at the monitoring network, you know, this area within Maricopa County has ozone monitors that show levels maybe above attainment, whereas if we talk about Joe City, which is maybe 80 miles outside of Flagstaff, it's not part of the same area that we're evaluating.

MEMBER GOLD: Because the air doesn't sort of sit there like it sits in Maricopa County?

MS. CARLTON: We do tend to have more inversion layers in Maricopa County, that's pretty common here.

MEMBER GOLD: Okay. I think I understand.

CHMN STAFFORD: I think we've been going for approximately 90-ish minutes. I think the court reporter is ready for a break. I think -- any objections --

MR. DERSTINE: No objection.

CHMN STAFFORD: I didn't think so. All right. Let's take a 15-minute recess.

We're in recess.

(Recessed from 3:41 p.m. until 4:01 p.m.)

CHMN STAFFORD: Let's go back on the record.

Mr. Derstine.

MR. DERSTINE: Yes. Thank you.

Q. Ms. Carlton, I want to make sure I understand. I think what the take-away from your -- your offset calculations there are that you need to -- essentially the credits that you use to meet the threshold requirements will exceed the amount of the emission reductions necessary to meet the threshold; do I -- am I thinking about that the right way?

A. (MS. CARLTON) Say that one more time for me.

Q. All right. So you're using -- you just indicated that you have to use credits that exceed the total, is the tons, or whatever the -- whatever the number is that you're having to control for; is that right? So there is a net benefit to the air quality in Maricopa County, because you're using credits that are -- that go beyond what would otherwise be the emissions from the expansion project?

A. (MS. CARLTON) That is correct.

Q. Okay. Anything else on offsets and credits?
A. (MS. CARLTON) I -- are there any other questions?
(No response.)
CHMN STAFFORD: Not from members at this time, apparently. If you could move a little closer to your microphone, though, please.
MS. CARLTON: Absolutely.
BY MR. DERSTINE:
Q. So I think now you want to move into the modeling that was done for the application?
A. (MS. CARLTON) Correct.
So we hired a national expert in environmental consulting to conduct modeling. The company name is RTP. They utilized EPA guidance and protocol, as well as guidance and protocol from ADEQ, which is the Arizona Department of Environmental Quality, as well as Maricopa County Air Quality's guidance and protocol.
Air modeling is required for this type of permitting and really what it does is it simulates the physical and chemical processes that affect air pollutants. And I think what's really important about the air modeling that is required during air permitting is that it's extremely site- and geographical-specific. And so very specific details related to the environment

around Redhawk, as well as the units themselves, are included in the air modeling. Details as exact as stack height, velocity of emissions leaving the stack, stack diameter, the climate around the facility for multiple years averaged are all put into the model to assess the impacts from the project.

The results of the modeling show that the total impacts are below the National Ambient Air Quality Standards and prevention of significant deterioration increments. And really, what does this mean? It means that the facility, the expansion, will not cause or contribute a violation of the National Ambient Air Quality Standards, and as a result of this modeling, we were not required to take any additional operational controls or modifications to the facility.

Q. And so the modeling, those are the conclusions that are -- that were reached based on the modeling analysis, and you presented that to Maricopa County Air Quality and they have, through their process, then, will evaluate and presumably, I guess, come to the same conclusion about the -- once they approve the permit application?

A. (MS. CARLTON) Correct.

So both our modeling protocol, so how we completed the modeling, as well as our modeling files, are all presented to the agency so they can essentially completely redo the modeling, if they like. But what's more likely to happen is they'll have their modeling experts evaluate what we did, the inputs that were utilized compared to what we've provided in the application to determine that our modeling was done correctly, and that the results were appropriate.

Q. Okay. Modeling is -- is required for the air permit application for the expansion project. Do you have to also include some sort of analysis on environmental justice considerations?

A. (MS. CARLTON) We are required to include environmental justice considerations. So environmental justice, for those who are less familiar with it, is defined by EPA to mean "The fair treatment and meaningful involvement of all people, regardless of race, color, national origin, or income, with respect to the development, implementation and enforcement of environmental laws, regulations, and policies."

Utilizing EPA guidance documents, we evaluated a three-mile radius around the plant, using the EJSCREEN model. EJSCREEN is a tool that has been developed by the EPA that has both environmental, as well as socioeconomic factors built into it. So you can fairly quickly get a, like a scorecard for your facility. What we found is that this facility, as mentioned earlier in this testimony, does not have very many people living around it. There's around 217 individuals that were identified in the EJSCREEN. And we did not find that the facility or the expansion of the facility would result in an adverse or disproportionate impact to the community.

But even though we did not find during the EJSCREEN and EJ evaluation -- "EJ" is short for environmental justice, my apologies, I started using the acronym without saying what it was -- we still are going through the meaningful involvement of the community through things like the open houses, both with the CEC process, but also with the air permitting process.

Q. When you mention, I forgot you said there were -- weren't many people, how many people identified are residents within your screening area?

A. (MS. CARLTON) Within the screening area, it identified 217 individuals, which would be considered very rural.

Q. Okay. And those 217 individuals were found within the three-mile area, which is used by -- or that falls within the guidelines for environmental justice evaluation; is that right?

A. That is correct.

Q. Okay. All right. You've covered the elements and what you presented to Maricopa County Air Quality in the permit application, do you want to summarize for the -- I think for the Committee what's in the permit and what you expect to receive back from Maricopa County Air Quality?

A. (MS. CARLTON) Definitely.

So, again, we're with the permit revision, and we wanted to highlight the main elements of the permit revision. So the combustion turbines themselves will be equipped with state-of-the-art emission control technology that reduces multiple pollutants by a factor of over 90 percent in some cases.

We will be utilizing ERCs, or emission reduction credits, that will result in an overall reduction in nitrogen oxide emissions in the non-attainment area, and will provide a net air quality benefit. The modeling results demonstrate that the total impacts are below the National Ambient Air Quality Standards, as well as the prevention for significant deterioration increments. And please note on the slide I do have a typo, it should be "prevention" for significant deterioration, not "potential."

And then the environmental justice did not identify any community with a potentially adverse, particularly -- I'm sorry, adverse or disproportionate impact.

Q. Okay. So that's what's in the application for the revision of the Title V permit for Redhawk.

Is there kind of a timeline for Maricopa County Air Quality to act on your application?

A. (MS. CARLTON) Absolutely.

So this is more of just a wrap-up and a reminder that this process is not near complete yet. When we look at the timeline, we submit it in April, but we're still in the drafting permit phase. And just as a remainder, we'll both have public comment, as well as EPA review, prior to the finalization of this permit. But once it is ready to be finalized, it will be issued by Maricopa County Air Quality Department. And then we will be able to begin actual construction of the facility.

Q. I guess that's an important point. You cannot start to construct the expansion project until you have received the final permit from Maricopa County Air Quality; is that right?

A. (MS. CARLTON) That is correct.

Q. Okay. Does that conclude your testimony?

A. (MS. CARLTON) It does.

Q. All right. Mr. Nicholls, are you ready to talk water?

A. (MR. NICHOLLS) I am.

Q. Okay. You have already been sworn. You've given the court reporter your name and address. Let's tell the Committee a little bit about yourself and your background.

A. (MR. NICHOLLS) Certainly.

I have a master's degree in geology from Brigham Young University, with an emphasis in hydrogeology. I'm an Arizona licensed professional geologist. I've been working for about 27 years across the Southwest on water resource projects, both in water supply and also addressing impacts to groundwater supply as well.

In particular, on this project, I was asked to evaluate the -- the impacts of the proposed expansion on the -- on the active manage- -- or the Phoenix Active Management Area management plan, and I'll discuss what that means here in just a few minutes, but also to evaluate the availability of groundwater relative to this project.

Q. And we asked you to look into those issues because the siting statute, the statute that does a lot of things, but in part, defines what this Committee is to consider, directs them to consider those two factors in 40-360.13, that is the potential impact of the project on and the availability of groundwater and the impact on the management plan, correct?

A. (MR. NICHOLLS) Correct.

Q. Okay. Do you want to outline your testimony and how you're going to get to those -- address those topics?

A. (MR. NICHOLLS) Certainly.

So I'll talk a little bit about some of the important regulatory and administrative features relative to the groundwater supply at the Redhawk facility. And we'll call this the groundwater setting where I'll discuss some of the hydrologic characteristics and regulatory or administrative characteristics of that groundwater supply.

I'll also talk a little bit about the regulatory framework for groundwater use at the Redhawk facility or that pertains to the groundwater use at the Redhawk facility. And I'll talk about my analysis of groundwater availability, in particular I conducted two tests using a groundwater model to evaluate the availability of groundwater for the proposed expansion.

Q. I'm going to guess that you may be talking a little fast for the court reporter, so if you'll just slow down a little bit, I think that will make things easier.

A. (MR. NICHOLLS) Will do.

Q. All right. Do you want to start with what you have identified as the groundwater study?

A. (MR. NICHOLLS) Certainly. On the -- on the right screen you'll see a map that shows a few of the important administrative and hydrologic boundaries relative to the site. On this map you'll see a gray dashed line that shows the edge of the Phoenix Active Management Area -- and again, I'll talk about what the Active Management Area is -- you'll also see a black solid line, which is the edge of the current Phoenix Active Management Area groundwater model. You'll see a blue shaded area, which is the Hassayampa groundwater sub-basin.

These features are relevant to the -- to the Redhawk Power Plant site, because the fact that it's located within the Phoenix AMA sets the regulatory framework for groundwater use at the plant. The fact that it's within the model boundary of the most recent Phoenix AMA model means that we can utilize that tool to evaluate the availability of groundwater.

And, of course, the fact that the plant is located in the southern portion of the Hassayampa groundwater sub-basin means that that's where any impacts from the groundwater use would most likely be observed. There is an indicator on this -- on this map that shows where the Redhawk Power Plant is located relative to these features.

There are two aquifers that underlie the plant site, and these aquifers have been named the upper alluvial unit and the lower alluvial unit. When we talk about an alluvial aquifer, it's relatively common to think of those in terms of sands and gravels that are saturated. So the aquifers are composed of those materials. The historic groundwater use in the vicinity we're at, the Redhawk Power Plant site, was dominated by agricultural uses, by irrigation.

As a result of these historic uses, APS holds a converted type I groundwater right in the quantity of 3,356 acre feet at the Redhawk Power Plant site.

Q. Now, Mr. Nicholls, I don't -- I think you were here -- you were here for when Member French asked questions about the two wells at the existing Redhawk Power Plant site, and whether those wells were permitted, and I might get this wrong, but in terms of the permitted volume for pumping -- did I cover those -- is that correct, Member French?

MEMBER FRENCH: Yes.

BY MR. DERSTINE:

Q. Okay. Can you address those questions?

A. (MR. NICHOLLS) I can.

We looked up the values associated with those wells, the permitted withdrawal values, and I do have numbers that I'll read so that they end up in the record here.

There are two wells that will be used for water supply and are currently used for water supply at the Redhawk Power Plant site. The registration of the first well is 55230361. And that well is permitted for a withdrawal of 4,035 acre feet per year. The second well is registration number 55231818, and that well is permitted for a withdrawal volume of 3,065 acre feet per year.

MEMBER FRENCH: Thank you.

MEMBER KRYDER: Mr. Chairman?

CHMN STAFFORD: Yes, Member Kryder.

MEMBER KRYDER: Question, Mr. -- I'm sorry, I can't see your name.

MR. NICHOLLS: Nicholls.

MEMBER KRYDER: -- Nicholls, the numbers that you've given in acre feet, and I did not get them, they came too quickly for me, this includes the whole area for the Palo Verde, not just for the Redhawk; is that correct?

MR. NICHOLLS: As I understand it, there were 1,700 -- I think it was 1,700 -- a little bit more than 1,700 acre -- acres of farmland that were retired at the Redhawk Plant site. And there was a water right associated with that farmed acreage that was converted to this right. And so I don't know specifically if this water right of 3,356 acre feet is available for use at the Palo Verde site.

MEMBER KRYDER: Okay. And from someone's earlier testimony, they said that -- or at least I understood that there were 500 acre feet currently being used at the Redhawk site, and the proposal that we're speaking of now would add 300 -- up to 300 acre feet, did I get those numbers correct?

MR. NICHOLLS: That's correct.

MEMBER KRYDER: So that's significantly under what your allocation is, your type I allotment is 4,000 and change, or something I heard; is that correct?

MR. NICHOLLS: It is significantly less than that value of 3,356 acre feet.

MEMBER KRYDER: And will APS sell those differences or you'll just hold onto them or are you being -- taking them home in your back pocket or what?

MR. NICHOLLS: Because it's a type I water right, that means that it is tied to the land, so it's appurtenant to the land and can't be severed from the land. So if APS were to develop future uses for groundwater, they would have to be on that site.

MEMBER KRYDER: Okay. So it is

specifically for power plants, and it is not for ag now that you moved to a type I; is that correct?

MR. NICHOLLS: That's correct. It's been converted from an agricultural right to an industrial water right.

MEMBER KRYDER: Okay. And that it has to be used specifically on that site for a power plant use as your -- as your classified type I license grants you; is that correct?

MR. NICHOLLS: Yes. And I think I would state, generally, it needs to be an industrial water use. And in this case, of course, that's probably several things related to the power plant, as well as for power generation.

MEMBER KRYDER: Okay. Thank you very much. That's quite enlightening. Appreciate it.

BY MR. DERSTINE:

Q. I think that the numbers that Committee Member Kryder gave you, those were supplied to you by APS that is that the -- historically the Redhawk Plant, the combined cycle plant has used, depending on the year, roughly 500 acre feet per year. I think, as Member Kryder mentioned, that's well below the 3,356 acre feet of rights that APS holds. But the water use for the existing plant is also augmented or supplemented by the

treated effluent from Palo Verde.
Did you hear that in the testimony?
A. (MR. NICHOLLS) Yes, I did.
Q. Okay. And then you also heard the testimony that the anticipated or projected water use for the expansion project is approximately 300 acre feet per year; is that correct?
A. (MR. NICHOLLS) Yes.
Q. Okay. And those are the numbers you used in your modeling?
A. (MR. NICHOLLS) That's correct.
Q. Okay. All right. Is there more you wanted to cover on the groundwater study or that was important for the Committee to understand?
A. (MR. NICHOLLS) I think that was it for this topic.
Q. Okay. I think you want to give us a bit of background on the Phoenix Active Management Area and how water -- groundwater use is regulated?
A. (MR. NICHOLLS) Yes, I do. Thank you.
My -- I used the term several times, "Active Management Area" and in case there are members of the Committee that aren't familiar with exactly what that term means, the Groundwater Management Act of 1980 authorized DWR to create areas where groundwater would be

managed in a more focused or more intensive regulatory setting. Those are referred to as Active Management Areas.

The map that you see on the right screen shows the location of Active Management Areas within the state of Arizona, as shaded green. You'll see some orange areas that are also areas of more intensive groundwater regulation that are referred to as irrigation non-expansion areas. They have different regulatory requirements than the Active Management Areas. The areas of the state where you -- where they are not shaded or areas that are not shaded have a less intensive groundwater regulatory setting.

You'll see on this map that the Redhawk Power Plant location is near the western edge of the Phoenix AMA. DWR has developed or is in the process of developing management plans to implement conservation criteria within each of the Active Management Areas. The current -- the current conservation requirements that pertain to the Redhawk Power Plant site are set forth in the fourth management plan. The Phoenix AMA, or Active Management Area, fourth management plan. That plan is in effect until December 31st of this year, after which the fifth management plan will become effective in January of 2025.

And, of course, the groundwater withdrawals at the Redhawk Power Plant site are ultimately limited by the type I -- the converted type I water right that I discussed a few minutes ago.

CHMN STAFFORD: Yes, Member Drago.

MEMBER DRAGO: Mr. Nicholls, are those plans updated on some sort of cadence, five years, 10 years?

MR. NICHOLLS: They are updated on a certain cadence. It's a very intensive stakeholder engaged process. And I can't speak specifically to how long it's taken to update some of those plans. I think they might have taken longer -- some of them might have taken longer than anticipated.

MEMBER DRAGO: Thank you.

BY MR. DERSTINE:

Q. You've touched on the active -- the Phoenix Active Management Area and the fourth management plan that's currently in effect, but the fifth management plan will become effective in January. I think the first area of your analysis was whether or not the expansion project is the -- the new additional eight combustion turbines would comply with the fourth or/and the fifth management plan?

A. (MR. NICHOLLS) Correct.

Q. Do you want to speak to that?
A. (MR. NICHOLLS) Certainly.
So the fourth management plan includes conservation requirements that are specific to combustion turbine power plants. Those conservation requirements address cycles of concentration, you know, in cooling towers, specifically. And, of course, those requirements, those conservation requirements that are articulated in the fourth management plan were sufficiently stringent that they were also carried forward to the fifth management plan without -- without change.
Of course, the Redhawk, the proposed expansion, will not rely on cooling towers, either the existing cooling towers or new cooling towers. From that perspective, the proposed expansion is compliant with both the fourth and the pending fifth management plans.
MEMBER KRYDER: Mr. Chairman?
CHMN STAFFORD: Yes, Member Kryder.
MEMBER KRYDER: Showing my ignorance, which is galloping at times, how do you measure a capacity in tons when you're talking about water? What do you measure?
MR. NICHOLLS: What do we measure? We're typically measuring flows in gallons per minute or we're

measuring water use in acre feet per year.

MEMBER KRYDER: But how does that convert to 250 tons -- tons per day, minute, hour, year?

MR. NICHOLLS: I think it -- as we see on the right slide, that reference is actually an excerpt from the -- from the fourth management plan, and as I understand that, that's 250 tons of cooling capacity, which I would have to defer to one of the engineering team to answer that. But the limitation that's articulated here is one of water quality. And so it's looking at the capacity of the cooling towers in tons of cooling capacity, which is a term I'm not able to fully define.

MEMBER KRYDER: Which would be like an air-conditioner that -- an industrial air-conditioner that gives seven tons of cooling or a ton and a half of cooling, is that the kind of measurement we're making?

MR. NICHOLLS: I can't say precisely with regards to tons of cooling, but I think that's -- that's an answer that we'll endeavor to get for you.

MEMBER KRYDER: Okay. Thank you very much. I was highly confused, but that's not normal -- or abnormal.

BY MR. DERSTINE:

Q. Mr. Van Allen, is that something we need to look into or can you speak to that now?

A. (MR. VAN ALLEN) I need to look into that, Mr. Derstine.

CHMN STAFFORD: Member Drago, you had a question?

MEMBER DRAGO: Yeah, thank you, Mr. Chairman.

I'm not sure if this would go to Mr. Nicholls or Ms. Carlton, but is the reason there are no cooling towers the use of SF6, so I saw that in your application, or greenhouse gas emission estimates?

MS. CARLTON: So the SF6 referenced in the air permits is related to SF6 breakers --

MEMBER KRYDER: A little closer to the mic, please.

MS. CARLTON: The SF6 referenced in the air permit application is related to SF6 breakers. I'll let Mr. Peter Van Allen answer why these do not have coolers associated with them.

MEMBER DRAGO: Thank you.

MR. VAN ALLEN: Member Kryder, so SF6 breakers, those are high-voltage breakers -- SF6 is used as a gas to insulate and eliminate an arc within the breaker, it's a sealed, enclosed breaker. You know, the gaskets in those breakers can deteriorate over time. And you could leak that gas out, and that gas is -- falls under one of the controlled substances under that greenhouse gas requirement.

So in simple terms, it's not a large source of release, right. I mean, very, very minor amounts would ever be -- would ever leak out of those. And I think we can track those and we report that. I'd have to investigate it a little further to make sure I understand.

BY MR. DERSTINE:

Q. I think the question was directed to the expansion project will not be utilizing cooling towers, the cooling towers are utilized in conjunction with the combined cycle units at the existing Redhawk Plant. The expansion project, these simple cycle units will not utilize cooling towers, you testified about the kind of cooling, I guess it's inlet cooling that you're using in conjunction with that technology, but they're not utilizing cooling towers; is that correct?

A. (MR. VAN ALLEN) The new -- the new units will not use cooling towers, that is correct.

Q. Okay. And is there a reason, I guess operationally, that they just aren't needed to operate these units?

A. (MR. VAN ALLEN) They -- so industry -- good question, Mr. Derstine. Industry has configured the units to really eliminate the need for water in the cooling process. They're sensitive to it. And they've done what they can to install a -- a -- what's called a fin fan cooler. It's much like the coolers we have at our homes for air-conditioning outside, right. You have the condensing unit, it's simply aluminum fins that have a fan and they pull heat off those systems.

So there's certain systems on a (GE) LM6000 that -- that the lube oil is cooled, right, for both the generator and the combustion turbines. So there's no -- the short answer is there's no cooling tower.

MEMBER DRAGO: Thank you.

BY MR. DERSTINE:

Q. And that gets -- that gets Mr. Nicholls to his conclusion that because there are no cooling towers used in conjunction with the expansion project, that the expansion project, in your opinion, is compliant with the fourth and the fifth active management plan; is that right?

A. (MR. NICHOLLS) Yes.

Q. So beyond whether or not the project will comply with the fourth and the fifth active management plan, you were asked to look at and analyze the impact of the project on groundwater availability, correct?

A. (MR. NICHOLLS) Correct.

Q. Okay. You want to take us through that analysis?

A. (MR. NICHOLLS) Certainly.

And so, as I -- as I described earlier, the Redhawk Power Plant site is within the model domain of the current groundwater model that DWR has developed for the Phoenix Active Management Area. This model is one that was published in 2023. It's a relatively new model. It represents the most up-to-date tool available to evaluate groundwater conditions throughout the Active Management Area.

On the right screen you'll see some examples of some of the geologic information that gets built into a model like this. And, for instance, on this upper panel, you'll see a depth to bedrock map. This tells us how deep bedrock is below ground surface, and helps us understand how thick the aquifer is at the vicinity or in the vicinity of the plant site.

This lower panel that you see shows a representation or a sampling of the geologic map in the area, which helps us understand the geologic materials that -- that -- that the aquifers are composed of beneath the site, but also helps us understand where bedrock is and the horizontal extent of the aquifer.

We used this model to evaluate pumping or the effects of pumping for both the existing Redhawk Power Plant water use and for the proposed expansion water use. And the evaluation included two tests, the first test was to consider draw-down impacts over a five-year period, from the proposed expansion pumping. The second test was to simulate pumping at the combined rate for both the existing power plant -- or the existing water use and also the proposed expansion water use over a period of 40 years.

The model assumed that all of the existing pumping that's -- that's currently ongoing and reported to DWR would continue throughout that simulation period, so throughout both the five-year simulation and the 40-year simulation.

MEMBER KRYDER: So -- Mr. Chairman?

CHMN STAFFORD: Yes, Member Kryder.

MEMBER KRYDER: So, Mr. Nicholls, back to the point that Mr. Derstine made a moment ago, by potentially utilizing 500 in the existing plant and 300 more in the new plant, you're significantly under the nearly, what was it, 3,700 acre feet that you're legally permitted, so that you're utilizing and drawing down over 40 years under your model much less water than you're legally permitted to; is that a fair set of statements?

MR. NICHOLLS: Member Kryder, yes, that's correct.
MEMBER KRYDER: Thank you.
BY MR. DERSTINE:
Q. So I want to make -- you used the 2023 DWR groundwater model, which is, I think, the most accurate way of kind of analyzing, I guess, groundwater availability, and you used that model for both tests; do I have that right?
A. (MR. NICHOLLS) That's correct.
Q. Okay. But the tests were different in that you used one test to -- I think you're going to tell us -- analyze the impact on on-site and neighboring wells utilizing the combined water use from the expansion project in the existing plant, and then you have more of a long-term, more of a macroanalysis on groundwater availability over the term of 40 years; is that -- did I get that close to being kind of your approach?
A. (MR. NICHOLLS) That's correct.
Q. Okay.
A. (MR. NICHOLLS) You've got that correct.
Q. Okay. You want to take us through test number one?
A. (MR. NICHOLLS) Certainly.
Of course, as you see on this slide, the wells

that are proposed for use for the expansion, for the plant expansion, are currently existing on-site. These are wells that are currently being used to provide water to the plant. And they have sufficient pumping capacity and withdrawal authority to support the proposed expansion.

The criteria that were used to evaluate availability of groundwater were, in part, based on well impact rules established by DWR. The well impact rules govern the amount of the -- the amount of water level impact that you might have on a neighboring well over a five-year pumping period.

On the right screen, you'll see a map that shows the location of wells within one-half mile of the Redhawk Power Plant site. The wells that you see with black symbols are those that are owned by other entities, folks that aren't APS. The wells that you see that are pink are owned by APS. This analysis focused, in particular, on the impacts from the proposed pumping or expansion pumping on the wells owned by others that are located off-site.

In accordance with the well impact rules, new wells may not induce more than 10 feet of additional draw-down to an existing registered well, over a five-year pumping period. More than 10 feet of draw-down is considered unreasonably increasing damage to the neighboring well.

The second part of the analysis evaluated the -- the amount of groundwater elevation change over a 40-year period that is directly attributable to the proposed expanded pumping at the Redhawk Power Plant site.

MEMBER KRYDER: Mr. Chairman?

CHMN STAFFORD: Yes, Member Kryder.

MEMBER KRYDER: You said a moment ago your draw-down 10 feet -- additional 10 feet neighboring wells five years and so on. And this is a regulation. This is a Maricopa regulation or it's a company model or who -- who is drawing the lines here?

MR. NICHOLLS: Thank you, Member Kryder. That -- that is a, you know, I'm going to mix this up whether it's in statute or rule -- but in effect it's a DWR regulation. And this applies within the Active Management Areas.

MEMBER KRYDER: Thank you.

BY MR. DERSTINE:

Q. So you're saying it's Member French's rule?

MEMBER FRENCH: It's not mine, but I believe it is in rule and within the management plan.

MR. DERSTINE: Thank you for that.

MR. NICHOLLS: I think, before I leave this slide, one thing I would like to point out to the Committee is this representation of a cone of depression. When we talk about this five-year analysis, what we're doing is we're really evaluating the horizontal extent of this cone of depression. The cone of depression is a funnel-shaped dimple in the water table that originates from the pumping well.

And what we want to do with our test is we want to see how far this cone of depression goes off-site, and to see how much draw-down it might induce at the neighboring wells.

BY MR. DERSTINE:

Q. And that's really what you're analyzing in test one, as you've identified it?

A. (MR. NICHOLLS) That's correct.

Q. Okay.

A. (MR. NICHOLLS) Yeah. And so to conduct this test, we -- we simulated pumping over a period of five years at a pumping rate of 800 acre feet, which is the 500 acre feet associated with the current Redhawk operations and the proposed expansion, to total 800 acre feet.

What you see on the right screen is a representation of the cone of depression at 500 acre feet pumping over a period of five years, and at a period of -- or at a rate of 800 acre feet pumping over five years. The blue lines that you see with the number on them, in particular the one that I'm highlighting here, so the blue line with the number 2, that means that the water table is down by about 2 feet at that location, when the Redhawk Power Plant wells are running at 500 acre feet.

If we compare that to the 800-acre-foot value, we see that there's a similar blue line with the number 3 on it, which shows us that the water table or the water level, the pumping water level is down about 3 feet at this location while the wells are running. And as we move outward, we see that the numbers on these lines become smaller, and this indicates the extent of our cone of depression. This is what we were looking to understand as that cone of depression becomes shallower away from the pumping wells.

The maximum draw-down that we observed was at the pumping wells, which is to be expected in our cone of depression, and that was 3.4 feet at the pumping wells after five years of pumping at 800 acre feet. Of course, because the cone of depression becomes shallower outward, the draw-down experience at other wells is less than that 3.4 feet. And the maximum draw-down observed at an off-site well owned by others was 2.6 feet over a period of five years.

MEMBER KRYDER: Mr. Chairman?

CHMN STAFFORD: Yes, Member Kryder.

MEMBER KRYDER: This is modeling, right, this is not actual draw-down, correct?

MR. NICHOLLS: Member Kryder, you're correct. This is from a groundwater model.

MEMBER KRYDER: And how -- how do you make a model -- I mean, give me, again, a pedestrian look at this thing. How do you make a model without pumping a lot of water out on the ground or putting it in a big truck or something?

MR. NICHOLLS: Member Kryder, I appreciate that question, and certainly I can explain that a bit. So the groundwater model is a computer representation. You can think of it in some ways as a three-dimensional drawing of the aquifers. That model is populated with data that DWR has collected, both pumping data and groundwater elevation data over a period of really decades to build that model. That model is then calibrated, which means the model is run for a simulation through time. It will -- let's say we model a 10-year period, and we compare the water levels predicted in the model to water levels that were measured over that 10-year period, and then adjustments were made until that model is as accurate as it can be made.

And so I think to your question, this is a model which means it's a numerical and computer representation, but it is based on and calibrated to actual measurements.

MEMBER KRYDER: And so that's a function, then, of the horizontal movement of the water basically moving back into the cone; is that a fair --

MR. NICHOLLS: Yes, that's a fair description. When we think of what that cone of depression looks like, when the pumps are running, we have this cone-shaped depression in the water table. When the pumps turn off, that cone refills, essentially.

MEMBER KRYDER: Thank you. That's very helpful.

CHMN STAFFORD: Quick follow-up question. In five years after operation, will there be measurements taken to confirm the accuracy of the model?

MR. NICHOLLS: Chairman -- Chairman Stafford, I don't know specifically that the water levels at these wells will be measured. Of course, there are wells in the area, index wells that DWR monitors on a regular basis. The model can be validated against those index wells to ensure that it is representative.

CHMN STAFFORD: Okay. What -- what has to happen for that to be checked?

MR. NICHOLLS: To validate the model, we would compare the model results that we have generated today, let's say five years in the future, against water levels that were measured at that point five years in the future. We would look at what the model predicted and compare it to what was actually measured.

CHMN STAFFORD: Right. But does that happen automatically or does someone need to instigate that? Is that something that DWR does routinely or is that they do it upon response to a complaint from someone saying their well -- the water is drawn down at their well?

MEMBER FRENCH: The Department of Water Resources has a field services team partnered with our modeling group that goes out and surveys the entire state with all of the index wells that they have and then any other wells that they -- that there are participants in the public that wish to have their wells monitored, and APS does have multiple wells that DWR has access to that are measured frequently.

CHMN STAFFORD: Okay. So then DWR would check the impact on the actual APS wells, and then they could kind of infer what the impact to the neighboring wells would be?

MEMBER FRENCH: All of the data that's collected through the surveys are then input into the models that DWR has. And all of the measuring data can be found on the Department's website as well.

CHMN STAFFORD: Okay. So I'm just -- how do we make sure that the -- that there is a -- that the draw-down in five years is approximately 2.6 feet at the nearest well? How do we -- how do we confirm that?

MEMBER FRENCH: So through the Department's monitoring program, they will go out and measure all of these wells over time. And they have been doing it for decades.

CHMN STAFFORD: Okay. So --

MEMBER FRENCH: And those will inform models in the future. And then if those models show that there is significant draw-down in certain areas, then management plan stipulations can be made.

CHMN STAFFORD: Okay. So that's going to happen. We don't need to add that as a condition or something --

MEMBER FRENCH: I don't think so.

CHMN STAFFORD: -- that's something they will do?

MEMBER FRENCH: Correct. I don't think an additional condition would be necessary for this.

CHMN STAFFORD: Yeah, that's what I was trying to find out, if it's necessary. Sounds like not. Thank you.

MEMBER DRAGO: Mr. Chairman?

CHMN STAFFORD: Yes, Member Drago.

MEMBER DRAGO: Since it's a technical discussion, I would suggest that maybe we put it in the context of assuming I'm a resident and I have a well near this area, is a draw-down of 3 feet, worst-case, a concern for me?

MR. NICHOLLS: Thank you, Member Drago. I think that depends on, I would say maybe the health of the well to begin with. If you're pumping just a few feet below the water level in that well, a draw-down of 3 feet might cause you to have to lower your pump or something like that.

We have looked at the wells that are closest to the site, and I think, if I go back a slide or two, when we look at these wells, you'll note that they're -- they're not residential wells. At the end of the day, these are associated with some of these solar facilities.

And the locations of these wells are based on DWR records. And so we think that some of these wells, for instance, this one at the top, 608003, is not as close to the site as it's shown. I think that it's actually up in this row between the solar panels. And so from that perspective these wells -- we don't expect a resident to have a problem from this.

But I would also add that APS, under the terms of a Special Use Permit from Maricopa County, is monitoring certain residential wells in the area for impacts related to pumping at Redhawk.

MEMBER DRAGO: Thank you.

CHMN STAFFORD: And how far away are those wells? There seems like, since we're not looking at this -- they're not in this picture, I'm assuming they're greater than three miles -- oh, this is half mile -- so they're greater than that.

MR. NICHOLLS: Thank you, Chairman Stafford. I think, as we heard in earlier testimony, that the nearest residence is 1.8 miles. I think it's fair to say that the nearest well is at least that far away.

CHMN STAFFORD: Okay. So those -- so those residences are using wells for their water?

MR. NICHOLLS: I know that some of them are. I don't know that all of them are.

CHMN STAFFORD: Okay. And what's -- obviously they have to be deeper than the water table.

Do we know what the depth of the table is and the typical depth of those wells? Because it seems that, depending on what that is, no one will even notice the three-foot draw-down.

MR. NICHOLLS: Yes. Thank you for that question. I do have some information with regards to the depths of those wells and the depths of the water table.

There is some geologic variability in the area. As we move towards the east and northeast, we see water levels, I would say in the vicinity of the elementary school, that are about 100 feet below ground surface. As we move further south in the Redhawk Power Plant area and south of that, we see water levels that are closer to 240 feet below ground surface.

The domestic wells that I looked at have depths ranging from about 175 feet to 450 feet or so, which means that they're producing, typically from the upper aquifer that I discussed earlier, the upper alluvial unit, whereas the -- the Redhawk wells are producing from the lower alluvial unit, so a deeper aquifer.

CHMN STAFFORD: Okay. Thank you.

BY MR. DERSTINE:

Q. Mr. Nicholls, I just wanted to clarify, and going back to your slide, if I can read it, 215. Can you back up to -- or go ahead, I guess, to 215. That was your conclusion slide. So the -- your model showed draw-down at the Redhawk wells after five years of 3.4 feet. Your model showed a maximum draw-down at the nearest registered off-site well, a well owned by someone other than APS, after five years to be 2.6 feet.

Do I have that right?

A. (MR. NICHOLLS) That's correct.

MEMBER KRYDER: Mr. Chairman?

CHMN STAFFORD: Yes, Member Kryder.

MEMBER KRYDER: Mr. Nicholls, you talk about the upper and the lower aquifer, there is a -- well, what's in between the two?

MR. NICHOLLS: Thank you, Member Kryder. The formation that is between those two, I believe is called the Palo Verde clay.

MEMBER KRYDER: And about how thick is that, or is it consistently thick or is it puddles and so on and so on?

MR. NICHOLLS: It will vary with -- with location, but my understanding is that at the Redhawk Power Plant site it's about 100 feet thick.

MEMBER KRYDER: So that a homeowner, as we were talking about it a couple of minutes ago, might go down and be in the upper aquifer or the industrial wells could then drill down through the Palo Verde clay and get down into the lower aquifer, and they would potentially see different impacts of any of your studies or any of the actual pumping, according to where their well was; is that right? They'd be in the upper or in the lower?

And then it seems also, from my limited knowledge of irrigation wells, becomes a function of the depth of the pump in the well itself, is that -- I hadn't heard you talk about that at all. Would you elaborate just a little bit on depth of the pump compared to depth of the well? I think there's two different metrics here.

MR. NICHOLLS: Certainly.

And I think to the first part of your question, you're correct, that pumpers that are producing groundwater from the upper aquifer may not see as significant effects from pumping in the lower aquifer. There is some separation between those. And so that -- that clay layer in between does mute the effect of pumping in the lower aquifer in the shallower upper aquifer wells.

With regards to the pump depth setting, that will be specific, I would say, well by well. It's also important to consider where that well is -- is perforated. And so some of the older agricultural wells might have perforations or openings to the aquifer in both the shallow and deeper aquifer units in -- in -- regardless almost of where you set your pump, you'll produce water from the most productive portion of that -- of that zone.

But pump depth is important, of course, to the homeowner, because if they have to lower their pump, it costs money. And if they don't have enough well left to lower their pump significantly, obviously, that costs more money.

MEMBER KRYDER: Thank you very much. That's greatly appreciated. Again, a view of water in the wells that are going to be used for the Redhawk expansion, those are down in the lower aquifer; am I correct?

MR. NICHOLLS: That's correct.

MEMBER KRYDER: Okay. And thank you. Appreciate it.

MEMBER GOLD: Mr. Chairman?

CHMN STAFFORD: Yes, Member Gold.

MEMBER GOLD: This is for Mr. Nicholls. Is there 100 percent separation between the upper and lower aquifer or do the waters intermingle?

MR. NICHOLLS: They do -- they do, Member Gold. I would say there's almost never 100 percent separation, just because there are potential conduit pathways. For instance, as I described a moment ago, some of the older agricultural wells might be perforated in both the upper and lower aquifers, meaning that they can facilitate communication or flow between the aquifers. There might also be some natural features within the clay where there's areas of sand that allow some communication. But, in particular, that's why I would describe the relationship between the lower and the upper as a muted relationship. It's not necessarily 100 percent sealed off one from the other, but it is very restrictive of flow between the two.

BY MR. DERSTINE:

Q. And I guess, to bring to a conclusion your analysis on test one, the impact to off-site wells, you were siting to the DWR regulations that provide that draw-down to a neighboring well of more than 10 feet after five years is unreasonable. Right here in this case your model shows draw-down of 2.6 feet after five years. And so it's well within the DWR regulations, and that supports your conclusion that the impact on neighboring wells would -- would not be unreasonable?

A. (MR. NICHOLLS) That's correct.

Q. Okay. Do you want to take us now to your test number two?

A. (MR. NICHOLLS) Certainly.

And so we also used the groundwater model to simulate pumping at a rate of 800 acre feet per year over a period of 40 years. We selected the period of 40 years because that's a period that we felt reasonably encompassed the operational life of the proposed expansion infrastructure.

That -- that 800 years -- or, sorry, 800 acre feet of pumping over 40 years resulted in a change in water levels in the aquifer of approximately 0.05 of a foot per year, which means over 40 years that the aquifer water level changes by about 2 feet, that is directly attributable to the proposed expansion pumping.

By comparison, the change in aquifer water levels as a result of all pumping, this means agricultural, municipal, industrial, and other pumping in the area is about 2.4 feet per year.

Q. I see your conclusion slide. I think you're ready to give us your conclusions.

A. (MR. NICHOLLS) I think so. Unless there are questions?

Q. All right.

A. (MR. NICHOLLS) Certainly. The Arizona Revised Statutes required that the proposed expansion be evaluated in terms of its potential impact on the -- on the Active Management Area management plan, and also in terms of groundwater availability.

In terms of groundwater availability, the model results show that sufficient groundwater is available to support both the expansion and the ongoing, or I should say, the continued pumping associated with current groundwater uses by others, including off-site pumpers.

And that this proposed expansion won't result in unreasonable impacts to off-site wells. And, of course, all of this pumping occurs within the water right, the type I water right that APS holds, which means that they have sufficient withdrawal authority to pump this groundwater.

Q. Mr. Nicholls, does that conclude your testimony?

A. (MR. NICHOLLS) Almost.

Q. Okay. Oh, I see there's page number 2 of conclusions, take us there.

A. (MR. NICHOLLS) Yeah. So the proposed groundwater pumping does result in a small change in the aquifer water levels over a period of 40 years, and that quantity is 2 feet, as I described earlier. And, of course, the proposed expansion is consistent and compliant with both the fourth and the pending fifth management plans for the Phoenix AMA.

MR. DERSTINE: Any further questions from the Committee on groundwater?

CHMN STAFFORD: Members?

(No response.)

MR. DERSTINE: All right.

Thank you, Mr. Nicholls.

CHMN STAFFORD: This seems like a fitting place to end our day.

MR. DERSTINE: Sounds like a -- right straight up 5:00, according to my watch, so --

CHMN STAFFORD: All right. Well, with that, we'll recess for the day and return tomorrow morning at 9:00 a.m.

(The hearing recessed at 4:59 p.m.)

STATE OF ARIZONA)
COUNTY OF MARICOPA)

BE IT KNOWN that the foregoing proceedings were taken before me; that the foregoing pages are a full, true, and accurate record of the proceedings all done to the best of my skill and ability; that the proceedings were taken down by me in shorthand and thereafter reduced to print under my direction.

I CERTIFY that I am in no way related to any of the parties hereto nor am I in any way interested in the outcome hereof.

I CERTIFY that I have complied with the ethical obligations set forth in ACJA 7-206(F)(3) and ACJA 7-206 (J)(1)(g)(1) and (2). Dated at Phoenix, Arizona, this 26th day of August, 2024.

ROBIN L. B. OSTERODE, RPR
CA CSR No. 7750
AZ CR No. 50695

* * * * *

I CERTIFY that Glennie Reporting Services, LLC, has complied with the ethical obligations set forth in ACJA 7-206(J)(1)(g)(1) through (6).

GLENNIE REPORTING SERVICES, LLC
Registered Reporting Firm
Arizona RRF No. R1035